CASE: UM 1910, 1911, 1912

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF BRIEF

July 26, 2018

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 1910, UM 1911, UM 1912

In the Matter of: PORTLAND GENERAL ELECTRIC COMPANY Investigation to Determine the Resource Value of Solar.	STAFF BRIEF

I. Introduction and background.

Docket Nos. UM 1910-12 comprise the second phase of the Commission's Investigation to Determine the Resource Value of Solar (RVOS). In Order No. 17-357 concluding Phase I, the Commission adopted, with some modifications, a valuation methodology designed by Staff consultant Energy + Environmental Economics (E3) for calculating a 25-year marginal, levelized value for generic, small-scale solar resources (hereinafter referred to as "RVOS Methodology" or "Methodology").[1] The Commission also identified and defined the elements of solar energy valued in the Methodology, which are energy, generation capacity, transmission and distribution capacity, avoided line losses, administration, integration, market price response, hedge value, environmental compliance, Resource Portfolio Standard compliance, and grid services.[2]

The Commission ordered Portland General Electric Company (PGE), Idaho Power Company (Idaho Power), and PacifiCorp to make individual compliance filings in new utility-specific dockets (Docket Nos. UM 1910-12) using the Methodology and inputs described in Order No. 17-357. The Commission ordered the utilities to explain how they went about determining the appropriate input for each element and implementing the Methodology and to

[1] *In the Matter of Public Utility Commission of Oregon Investigation to Determine the Resource Value of* Solar (UM 1716 Phase II), Order No. 17-357.
[2] *Id.*

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provide work papers to build a robust record that would facilitate the Commission's final determination of an RVOS Methodology. The Commission further specified that Staff and intervenors would have the opportunity to respond to the compliance filings and that all parties should address certain general issues such as the levelization period and how to determine RVOS for a utility scale solar resource. Notably, the Commission reserved the option of modifying the Methodology in Phase II.

As discussed by the Commission in its order concluding Phase I of this investigation, the Commission intended to use the utilities' Phase II compliance filings to evaluate the Methodology and presumably, modify the Methodology or how to determine inputs if information submitted in Phase II showed modification is appropriate. PacifiCorp, PGE, and Idaho Power all submitted compliance filings in late 2017. Staff, the Oregon Department of Energy (ODOE), the Oregon Citizens' Utility Board (CUB), Renewable Northwest (Renewable NW), and the Oregon Solar Energy Industries Association (OSEIA) filed testimony on March 6, 2018, in Docket Nos. UM 1910-12. Of these parties, only Staff filed cross-response testimony on April 20, 2018. PGE, PacifiCorp, and Idaho Power Company all filed reply testimony in their respective dockets on the same day Staff filed its cross-response testimony. The Commission examined witnesses on June 25, 2018.

The disputes in these dockets largely concern how to determine the values of each of the elements included in RVOS. The mathematical workings of the RVOS Methodology are not at issue. However, to provide context to the disputes in these dockets, Staff attaches to this brief an excerpt of UM 1716 Phase I testimony by Staff expert witness Arne Olson describing how the Methodology works.[3]

[3] Attachment (Docket No. 1716 Phase II Staff/200, Olson/29-34).

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In the sections below, Staff lists the elements valued in RVOS, the definition determined by the Commission and Commission directions on how to determine each element's value. Staff lists the values filed by the utilities for each element and addresses whether the three utilities have complied with the requirements of Commission Order No. 17-357. Staff also identifies and explains recommended modifications to the Phase I Methodology that will help to ensure some consistency and predictability in the determination of RVOS for all three utilities.

II. Elements.

A. Energy.

Definition: Marginal avoided cost of producing or procuring energy, including fuel, O&M, pipeline costs and all other variable costs.

Input: Utilities shall produce a 12 x 24 block for energy prices and include a detailed explanation of how they created the block. Utilities shall demonstrate through statistical analysis that their energy values are scaled to represent the average price under a range of hydro conditions.

1. Methodology.

The value for energy has three components: (1) the forward price curve, (2) the 12 x 24 shape, and (3) hydro variability. Staff recommends the Commission slightly modify the methodology set forth in Order No. 17-357 to provide more specificity regarding the source and vintage of the forward price curves used by the utilities. Staff also recommends that the Commission provide more specificity on how the utilities should determine the 12 x 24 shape.

In Order No. 17-357, the Commission noted that it expected utilities would use the same source for forward price curve as is used to determine standard avoided cost prices.[4] Staff recommends that the Commission specify this is a requirement (not an expectation). Second, Staff recommends that the Commission specify that utilities should use the most recently available forward price curves for the RVOS calculation.

[4] Order No. 17-357, p. 3.

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PacifiCorp asserts Staff's recommendation regarding the vintage of forward price curves is inconsistent with the Commission's direction to use the standard avoided cost price methodology.[5] This criticism is not compelling. Staff acknowledges that under the Phase I Methodology, a few of the inputs into RVOS are taken directly from the utilities' IRPs and mirror the inputs into avoided cost prices. Forward market prices differ from these other inputs in that it is easier to vet new forward market curves than it is to vet new capital costs or contribution to peak of a proxy solar resource.

2. Utility values.

PacifiCorp Nominalized Level	PacifiCorp Real Levelized	PGE Nominal Levelized	Idaho Power Levelized
$30.58	$24.17	$24.98	$29.74 $25.30 Revised[6]

3. Utility compliance.

a. Forward price curve.

PGE, PacifiCorp, and Idaho Power all sourced their forward price curves for their RVOS filings as expected by the Commission, using the same sources as used for standard avoided cost prices. It is not clear that all utilities used the most recently available forward price curve, but this was not a requirement under Order No. 17-357. Staff recommends that the Commission require that utilities use the most-recent vintage of forward price curve in their next RVOS filings.

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[5] PAC/300, MacNeil/12-13.

[6] Many of the values in Idaho Power's initial filing were based on information in Idaho Power's 2015 IRP. Idaho Power revised these values after the Commission acknowledged its 2017 IRP.

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b. 12 x 24 shape.

Each of the three utilities used a different method to shape the energy prices. After calculating forward monthly on-and off-peak prices based on three market hubs (Mid-Columbia, Palo Verde, and California-Oregon Border), PacifiCorp shaped those prices to settlement prices from three load aggregation points (LAPs) from the energy imbalance market (EIM) for the 12-month period ended September 2017.

PGE created daily shape factor profiles for each month using hourly prices for 2024 produced by AURORA. PGE then applied the shape factors to the weighted average annual price (based on monthly prices discussed above) for each year to create daily prices profiles for each month of each year (or 12 x 24 blocks).

In its initial filing, Idaho Power applied a price shape factor of one, resulting in a flat shape applied to the annual energy value. Staff testified that this flat shape did not comply with the Commission's instructions in Order No. 17-357. In its second round of testimony, Idaho Power changed its shaping method to use actual hourly Mid-Columbia ("Mid-C") market prices for 2017 to develop an index. Staff has concerns with revised method because Idaho Power's shaping factors do not average one across the year as they should.[7]

Staff recommends the Commission direct Idaho Power to either correct their shaping of 2017 hourly prices or use a different method to obtain a 12 x 24 shape for market prices. In absence of any other vetted alternative, Staff recommends that Idaho Power use an economic dispatch model to create the shape as PGE did.

Staff also recommends that the Commission direct PacifiCorp to employ an economic dispatch model in the creation of a 12 x 24 shape. Staff testified regarding its concerns with

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[7] The procedural schedule did not give Staff an opportunity to provide testimony in response to Idaho Power's modified shaping method.

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PacifiCorp's EIM method in opening testimony. EIM settlement prices may inform the marginal value for a subset of PacifiCorp's resources, but the shape of those prices does not reflect the value to the system as a whole.[8] Accordingly, PacifiCorp's use of EIM transactions as the sole source of information for the 12 x 24 shape is inappropriate.

Staff believes PacifiCorp's dispatch model can be configured to provide information that may be used to create a 12 x 24 forecast of hourly values that is better suited to measuring the value of solar to PacifiCorp's system than a shape based on historical transactions of multiple utilities in the EIM. Staff recognizes that PacifiCorp has not yet used is AURORA model for this purpose. However, PacifiCorp appears to acknowledge that it is possible.[9] And, while Staff does not believe PacifiCorp should rely so heavily on EIM transactions as it did in its initial filing, Staff does not oppose PacifiCorp relying on information regarding these transactions as well as information obtained from an economic dispatch model to determine the 12 x 24 shape.

Finally, for the reasons stated above, Staff also recommends that the Commission reject OSEIA's proposal to use historic information regarding EIM transactions to shape market prices.[10]

c. Hydro variability.

Order No. 17-357 directed the utilities to include a narrative explanation as well as statistical analysis demonstrating how their energy values are scaled to represent the average price under a range of hydro conditions. Staff had criticisms of each utility's method of capturing the complex relationship between hydro conditions and market prices. Upon review of the utilities' testimony filed on April 20, 2018, Staff believes each utility has proposed an adequate method of

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[8] UM 1910 Staff/200, Andrus/4.

[9] PacifiCorp testified "[w]hile the Aurora model results reflect a fundamental market view, PacifiCorp has never configured the model to report hourly results and it is not clear whether doing so would provide reasonable results." Staff interprets this testimony to mean PacifiCorp could configure he model to report hourly results.

[10] Staff/300, Andrus/5.

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incorporating the impact of hydro on market prices and has no recommended changes to the utilities' methods.

B. Generation capacity.

Definition: The marginal cost of building and maintaining the lowest net cost generation capacity resource.

Input: Utilities shall determine the capacity value consistent with the Commission's standard nonrenewable QF avoided cost guidelines, with one adjustment. Utilities should remove forecasted solar resources from resource stack and adjust deficiency period start date if appropriate. When the utility is resource sufficient, the value is based on the market energy price. When the utility is resource deficient, the value is based on the contribution to peak of solar PV, multiplied by the cost of a utility's avoided proxy resource.

1. Method.

The Commission has directed utilities to use their standard avoided cost methodology to determine the input for generation capacity for the RVOS calculation, modified to ensure that forecasted solar resources are not part of the utility's forecasted resource stack for purposes of determining when the utility will acquire new capacity.[11] The avoided cost methodology is not well suited for capturing the value of the incremental capacity additions provided by solar resources. The Commission recognized this shortcoming in Order No. 17-357 and directed Staff to conduct a workshop on this issue, although not necessarily for the purpose of improving the method for these initial RVOS compliance filings. The Commission also "invited parties to explore options for valuing capacity additions incrementally during resource sufficiency."[12]

OSEIA recommends that the Commission recognize the incremental capacity additions and shorter lead times of solar resources by advancing the resource deficiency date by three years for

[11] Order No. 17-357, p. 8.
[12] Order No. 17-357, p. 7.

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PGE and by four years for PacifiCorp and Idaho Power Company.[13] OSEIA also recommends that the utilities use the short run marginal costs for operations and maintenance (O&M) at existing marginal fossil plants as a proxy for the value of capacity during the sufficiency period.[14]

While Staff recognizes the shortcomings of the standard avoided cost methodology for estimating the generation capacity value, Staff does not support the alternate methodology proposed by OSEIA. OSEIA has not presented sufficient evidence to show that advancing the start of the deficiency period by the three years for PGE and four years for PacifiCorp and Idaho Power provides a more accurate capacity value.

Staff recommends that the Commission allow Staff to continue the investigation of possible improvements to the method to capture the incremental value of incremental capacity additions as ordered in Order No. 17-357, but make no change to the method to account for incremental capacity additions at this time. Staff plans to convene a workshop on this issue as directed by the Commission and believes further discussion with the utilities and stakeholders may lead to a more precise method for capturing the incremental capacity value of solar resources.

Staff also does not support OSEIA's proposal to base the sufficiency period capacity value on short run marginal O&M costs of its marginal fossil plants. During a utility's sufficiency periods, the standard avoided cost price is based on forward market prices, which include a value for capacity. The Commission has previously rejected the use of marginal O&M

[13] OSEIA/100, Beach/6.

[14] OSEIA/100, Beach/6. CUB's direct testimony criticized the Commission's method of valuing capacity during the utility's sufficiency period. CUB/100, Gerhke/ 4-5 . CUB's witness retracted this criticism at the hearing on June 25, 2018. (6/25/2018 TR 51-52).

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costs for avoided cost prices during a utility's sufficiency period on the basis the marginal costs would not compensate a qualifying facility for capacity.[15]

Staff does recommend one additional requirement to the method for determining the generation capacity input, however. To determine the capacity value during a resource deficient period, a utility multiplies the contribution to peak (CTP) of a solar resource by the capacity cost of the utility's proxy resource in its IRP.[16] Staff recommends that the Commission require that until authorized to do otherwise, each utility must use the CTP of an Oregon solar resource taken from their most recently acknowledged IRP.[17]

PacifiCorp observes that it can obtain individualized capacity values for different solar resources based on the 12 x 24 Loss of Load Probability (LOLP) from its IRP capacity contribution study. Specifically, the capacity value of a proposed resource would be weighted based on the LOLP in each hour.[18]

Staff agrees that there are applications of the RVOS Methodology that would require or be served by the method proposed by PacifiCorp, as this additional specificity should result in a more accurate project- or location-specific RVOS. However, the LOLP analysis represents an increased level of complexity in calculating RVOS, leading Staff to believe that a utility employing this method should engage with stakeholders before using it to determine capacity values. Although the methodology to determine RVOS may be adapted to provide the granularity proposed by PacifiCorp for certain applications, i.e. the community solar program, Staff believes it is premature to do so for the RVOS Methodology that results from this investigation.

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[15] Order No. 05-584.
[16] Order No. 17-357, p. 7.
[17] Staff/100, Andrus/23.
[18] PAC/100, MacNeil/21.

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2. Utility values.

PacifiCorp Nominal Levelized	PacifiCorp Real Levelized	PGE Real Levelized	Idaho Power Real Levelized
$12.20	$8.65	$7.30	$15.30 $13.50 Revised

3. Utility compliance.

As discussed above, Staff recommends the Commission specify that the generation capacity value during the utility's deficiency period should be calculated using the CTP of an Oregon solar resource taken from the utility's most recently acknowledged IRP. The method employed by PacifiCorp in its initial RVOS filings would not comply with this requirement for the reasons discussed above.

C. Transmission and distribution capacity.

Definition: Avoided or deferred costs of expanding, replacing, or upgrading transmission and distribution (T&D) infrastructure.

Input: Utilities shall develop a system-wide average of the avoided or deferred costs of expanding, replacing, or upgrading T&D infrastructure attributable to incremental solar penetration in Oregon service areas.

1. Method.

As with generation capacity, Staff recommends the Commission limit the methods a utility can use to determine the value for T&D capacity pending further investigation. Staff recognizes the importance of obtaining additional granularity in the determination of the T&D capacity value. However, the data necessary to obtain a more location specific T&D capacity value is not yet accessible.

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In Order No. 17-357, the Commission noted that utilities could use their most recent Marginal Cost of Service Study (MCOS) to develop the input for T&D Capacity, but were not required to do so.[19] Of the three utilities, only PGE used a MCOS to determine the value for T&D capacity. Idaho Power and PacifiCorp used alternative methods based on the costs of near-term planned transmission and distribution resources that they identify as subject to deferral. Staff recommends that the Commission not allow PacifiCorp and Idaho Power to use these alternative methods.

To determine the value for avoided distribution capacity, PGE used a MCOS prepared for its 2017 general rate case. To determine the avoided transmission capacity value, PGE estimated the amount of transmission service that could be avoided due to solar generation and determined its value using the cost of Bonneville Power Administration's (BPA) 2018 tariffed Firm Point-to-Point Transmission service with Scheduling, System Control, and Dispatch Service.[20]

Idaho Power calculated the total savings from the limited subset of all the T&D projects within its 2016 budget that it identified as deferrable. After it determined which projects that it believe to be deferrable as a result of EE, it combined the benefits and divided by the total annual EE reduction forecast over the service area.[21]

PacifiCorp used a similar methodology to that used by Idaho Power. PacifiCorp updated the T&D deferral calculation that it used for the analysis of demand-side management resources in its 2017 IRP. PacifiCorp obtained the average value of deferred T&D investment based on three specific forecasted capacity additions (T&D projects) that PacifiCorp believes are subject to deferral by solar penetration in its Oregon territory.[22]

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[19] Order No. 17-357 p. 9.
[20] UM 1912 PGE/400, Murtaugh/8.
[21] UM 1911 Idaho Power/100, Haener/9-10.
[22] UM 1910 PAC/200, Putnam/4.

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While Staff appreciates PacifiCorp's and Idaho Power's efforts to obtain more granularity, Staff does not believe the methods provide the "system-wide average" specified by the Commission. As noted by Arne Olson of E3, Oregon utilities currently do not produce values that specifically measure avoidable T&D costs. Mr. Olson recommended that in the absence of more specific values, MCOS provide a reasonable basis for calculating avoided T&D capacity value.[23]

In Order No. 17-357, the Commission specified that utilities should explain in their initial filings what information and methodologies they currently have for location specific distribution planning and how these could be used or adapted to advance the granularity of this element for the next iteration of RVOS.[24] The Commission did not instruct utilities to attempt to incorporate that granularity into the T&D capacity value for this iteration of RVOS. The methods devised by PacifiCorp and Idaho Power confirm that ad hoc methods are not an improvement on the MCOS-method identified by the Commission.

Staff recommends that the Commission specify that to determine the value associated with distribution capacity, utility should base the capacity value on a recent or relatively recent MCOS, or if a MCOS is not available, a utility should use the National Economic Research Associates (NERA) regression method proposed by OSEIA to determine the T&D generation input.[25]

To determine a system-wide average transmission capacity, utilities should use a method similar to that used by PGE. The utilities should not determine on a location-by-location basis which transmission investments solar generation will allow the utility to avoid. Instead, the utilities should determine a more general estimate based on amount of firm transmission service

[23] UM 1716 Staff/401, Olson/22 (Staff Response to TASC DR No. 19).
[24] UM 1716 Staff/401, Olson/22 (Staff Response to TASC DR No. 19).
[25] OSEIA/100, Beach/23.

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distributed solar generation would allow the utility to avoid and the cost of firm transmission service.

2. Utility values.

PacifiCorp Nominal Levelized	PacifiCorp Real Levelized	PGE Real Levelized	Idaho Power Real Levelized
$0.08	$0.05	$8.08	$0.87 $0.54 Revised

3. Utility compliance.

PGE produced an adequate system-wide average of avoided T&D costs attributable to incremental solar penetration in its Oregon service area. Idaho Power and PacifiCorp did not. Staff recommends that the Commission specify the two permissible methods for determining the avoided distribution value and the permissible method for determining the avoided transmission value and direct PacifiCorp and Idaho Power to file values based on these methodologies.

D. Line losses.

Definition: Avoided marginal electricity losses.

Input: Utilities shall develop hourly averages of avoided marginal line losses attributable to increased penetration of solar PV systems in Oregon service areas. The incremental line loss estimates shall reflect the hours solar PV systems are generating electricity.

1. Method.

OSEIA recommends that the method for determining the value for line losses be changed so that it is based on an estimate of marginal line losses rather than average line losses.[26] OSEIA notes "the use of average losses fails to capture the fact that the reductions in line losses on the

[26] OSEIA/100, Beach/25.

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margin, from small changes in load on the system, are significantly greater than average losses."[27]

Staff believes that OSEIA's criticism is not directly on point. Notably, the Commission ordered the utilities to determine hourly averages, by month, for the daytime hours when load on the system is higher, losses are greater, and solar is generating. The Commission expected the values to recognize and reflect that there are seasonal and daily variations in line loss impacts with higher temperatures and higher loads having higher losses."[28]

2.Utility values.

PacifiCorp Nominal Levelized	PacifiCorp Real Levelized	PGE Real Levelized	Idaho Power Real Levelized
$1.96	$1.54	$1.48	$2.54 $2.05 Revised

3. Utility compliance.

Each utility used a slightly different approach to derive the losses values. However, each utility did provide values that represent estimates of seasonal and within-day changes. Staff believes that PacifiCorp, PGE and Idaho Power did comply in supplying the Phase II line losses. PacifiCorp began with the transmission, primary, and secondary losses currently reflected in retail rates, which reflect the company's most recent line loss study. For the RVOS line loss element, PacifiCorp conducted power flow studies that identified the primary and secondary line losses at 100 percent, 90 percent, and 75 percent of both winter and summer peak loads to supplement the previous study. These losses were then fitted to a 12-month and 24-hour profile to create the marginal losses for resources connected at either the primary or secondary voltage

[27] OSEIA/Beach/25.

[28] Order No. 17-357, p. 10.

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level. PacifiCorp testified that obtaining location specific line losses would have little impact and that it is not worth the significant amount of time it would take.

PGE calculated seasonal and high- and light-load line loss data. PGE captured losses for each distribution power transformer in substations, as well as each of their corresponding distribution feeders. For the distribution feeders, losses were calculated for all primary circuits. Utilization transformers, secondary, or service wires were not included in this study. PGE does not have hourly data and would need to undertake a study of the T&D system and assigning net system load estimates by hour throughout the year. PGE testifies that a more expedient option would be to calculate a handful of representative samples based on net system load estimates. PGE testifies that this method is similar to the studies that PGE has produced for the initial proposal of the line loss element, but with additional seasonal/daytime variation.

Idaho Power uses loss data from 2012 to develop average losses for on-peak, mid-peak, and off-peak hours in summer and winter. All the values were between 8.5 percent and 8.7 percent.

E. Administration.

Definition: Increased utility costs of administering solar PV programs.

Input: Utilities shall develop hourly averages of avoided marginal line losses attributable to increased penetration of solar PV systems in Oregon service areas. The incremental line loss estimates shall reflect the hours solar PV systems are generating electricity.

1. Method.

Order No. 17-357 did not specify a method but referred to E3's explanation that administration costs should be incremental to costs that the utility incurs for any other

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customer account and incremental to any costs paid by an interconnecting solar generator.

2. Utility values.

PacifiCorp Nominal Levelized	PacifiCorp Real Levelized	PGE Real Levelized	Idaho Power Real Levelized
($2.59)	($1.80)	($5.58)	($47.77) ($18.20) Revised

3. Utility compliance.

PacifiCorp and PGE created an adequate method of determining an hourly value for administrative costs associated with solar. Idaho Power did not. Idaho Power based its value on the costs to administer a complex and small pilot program. However, these costs are likely not representative of costs associated with future solar development. Also, they are likely not representative of costs Idaho Power incurs for other solar programs such as net metering.

F. Integration.

Definition: The costs of a utility holding additional reserves in order to accommodate unforeseen fluctuations in system net loads due to addition of renewable energy resources.

Input: Utilities shall develop estimates of integration costs based on acknowledged integration studies.

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1. Method.

Costs to integrate solar resources are likely different than costs to integrate other intermittent resources. However, some integration studies are focused on the costs of integrating both solar and wind resources. Accordingly, Staff recommends that the Commission specify that any integration study used to estimate integration costs for RVOS must have sufficient information to allow a utility to at least extrapolate the cost of integrating only solar resources.

2. Utility values.

PacifiCorp Nominal Levelized	PacifiCorp Real Levelized	PGE Real Levelized	Idaho Power Real Levelized
($0.82)	($0.63)	($0.83)	($0.56)

3. Utility compliance.

All three utilities provided values for integration based on integration studies. However, in its direct testimony, Staff noted that it could not discern whether or how PGE differentiated between costs to integrate different types of variable resources, which include non-solar generation.[29] In response to Staff's concern regarding the need to determine a value that is based on costs to integrate only solar resources, PGE noted that it is currently developing an integration cost study that will address both incremental solar and incremental resources separately.[30]

G. Market Price Response.

Definition: The change in utility costs due to lower wholesale energy market prices caused by increased solar PV production.

1. Method.

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[29] UM 1912 Staff/200, Andrus/10.

[30] UM 1912 PGE/600, Goodspeed-Jordan/7.

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The exact formula provided by E3 multiplies the change in wholesale prices by the size of the net short/long position, and divides this number by the amount of solar generation that caused that change in wholesale prices. The two latter inputs (the size and direction of the utility's market position and size of solar resources) are easily accessible, however the magnitude of potential price change is difficult to estimate. E3 suggested deriving the magnitude of potential price change in one of two ways: (1) use a range for the market price elasticity from -.001 percent to -.002 percent or (2) conduct sequential runs of a production simulation model with and without the solar resource in order to measure the price response. The first option is simple, but does not provide the granularity of price responses during different periods, which is crucial when considering production-limited solar PV resources.

Staff does not recommend any modification to the method suggested by E3. However, as explained below, Staff recommends that the Commission require that the adjustment not be performed as an outboard adjustment as PacifiCorp has done.

2. Utility values.

PacifiCorp Nominal Levelized	PacifiCorp Real Levelized	PGE Real Levelized	Idaho Power Real Levelized
$0.15	Not provided	$1.81	$0.00

3. Utility compliance.

Staff believes the PacifiCorp's and Idaho Power's calculation of the market price response value are inconsistent with the E3 proposed methodology.

Idaho Power determined that it sold more energy to the market than it purchased, and used negative market price elasticity of -0.001 per kWh to calculate the market price response.

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Staff disagrees with Idaho Power's analysis. As long as the marginal cost of solar is below the market price of electricity, the marginal impact of every kilowatt addition will depress market prices. Accordingly, a zero value is appropriate only if there is no anticipated solar development.

PacifiCorp determined the market price response as an outboard adjustment, which is not contemplated in the methodology proposed by E3. Staff recommends that the Commission require to follow the Methodology as adopted by the Commission.

H. Hedge value.

Avoided cost of utility hedging activities, i.e., transactions intended solely to provide a more stable retail rate over time.

Input: Utilities are to assign a proxy value of five percent of energy.

1. Method.

By generating without fuel, solar provides some price certainty to the utilities. As this reduction in exposure is a cost for which utilities are willing to pay, solar generation provides a quantifiable benefit to this avoided cost. E3 did not provide a method to determine this hedge value utility by utility. E3 recommended the Commission require utilities to use a proxy equal to five percent of the energy value on the basis that five percent is consistent with a study performed in the Northwest.[31]

Each of the three utilities noted some concern with the five percent proxy, notably that the five percent did not necessarily represent the hedge value of solar in light of their particular resource acquisition and hedging strategies. Staff agrees with the utilities that a more utility-

[31] Staff/100, Andrus/45-46.

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specific value would be preferable to a proxy, but at this time, no there is no reasonable alternative methodology that could produce this more specific value.

Only OSEIA suggested an alternative method for determining the hedge value for RVOS. OSEIA observes that distributed solar reduces ratepayers' exposure to volatile fossil fuel prices and other market price spikes. OSEIA asserts that therefore, the hedge value of a solar resource should be equal to the costs that the utility would have to incur to fix the costs for its avoided natural gas burn for the life of the renewable resource.[32] OSEIA testifies that using a method developed by Clean Power Research method results in values for the hedge element that range from $18.00 to $23.00 per MWh.

The three utilities disagree with OSEIA's proposal to determine the hedge value of a solar resource. PacifiCorp testifies that OSEIA's proposal bears no resemblance to PacifiCorp's actual resource planning and notes the cost of a 25-year hedge suggested by has an enormous risk premium.[33] PGE similarly notes that not many traders take a 25-year position on a standard commodity hedge.[34]

Staff agrees with the concerns noted by the utilities. Utilities are not willing to pay between $18.00 and $23.00 per MWh to hedge against market volatility. Staff recommends that the Commission reject OSEIA's proposed modification to the Methodology.

2. Utility values.

PacifiCorp Nominal Levelized	PacifiCorp Real Levelized	PGE Real Levelized	Idaho Power Real Levelized
$1.54	$1.21	$1.25	$1.49 $1.26 Revised

[32] OSEIA/100, Beach/iv.
[33] UM 1910 PAC/300, MacNeil/37-38.
[34] UM 1912 PGE/600, Goodspeed-Jordan/11.

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3. Utility compliance.

All three utilities complied with the methodology in Order No. 17-357.

I. Environmental compliance.

Definition: Avoided cost of complying with existing and anticipated environmental standard.

Input: For informational purposes, utilities shall estimate the avoided cost based on a reduction in carbon emissions from the marginal generating unit. To value future anticipated standards utilities should use the carbon regulation from their IRP.

1. Method (informational).

PGE utilized the mid-national carbon price forecast from Docket No. LC 66 – PGE's 2017 IRP. This forecast was published by Synapse Energy Economics in its "Spring 2016 National Carbon Dioxide Price Forecast." Idaho Power included a zero value for environmental compliance based on the fact it modeled zero compliance costs in its 2015 IRP.

PacifiCorp differentiated between cost compliance during periods of resource sufficiency and deficiency. PacifiCorp included no compliance cost associated with market purchases during the sufficiency period. For the deficiency period, PacifiCorp based the value on PacifiCorp's cost to comply with the Clean Power Plan (CPP) year during the 25-year period, PacifiCorp explains that CPP compliance costs average around $6 per ton from 2024 to 2028 and that starting in 2029, emissions drop below cap threshold so compliance payments cease. PacifiCorp notes that deficiency period starts in 2028, so only includes compliance costs that would be incurred in 2028, despite the fact that PacifiCorp's market purchases hold a risk of compliance costs in other years.

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2. Utility values (informational).

PacifiCorp Nominal Levelized	PacifiCorp Real Levelized	PGE Real Levelized	Idaho Power Real Levelized
$0.11	$0.08	$11.41	$0.0

3. Utility compliance.

Staff believes that PGE's approach complies with the Methodology as it is derived from the IRP and it supplies a reasonable estimate of future compliance costs. Idaho Power complied in terms of applying the zero carbon price from its 2015 IRP; however, this is not sufficient given the Commission's intent to explore this RVOS element for informational purposes, and emerging events regarding carbon regulations in Oregon. PacifiCorp's approach of quantifying environmental compliance costs only in a single year is insufficient, and should be replaced by carbon compliance costs used in the 2017 IRP.

Given that this element is included for informational purposes, it does not impact the total RVOS values at this time.

J. RPS compliance:

Definition: To be determined.

Input: The utilities shall use a value of zero in their initial Phase II filings.

1. Method.

The Commission did not define this element. Staff notes that at minimum, the value of Renewable Portfolio Standard (RPS) Compliance value could be as suggested by E3, which is the avoided cost of compliance based on the reduction in load and the levelized cost of the

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marginal renewable resource installed in the year when utilities need to comply with RPS requirements.[35]

H. Grid services.

Definition: The potential benefits of solar PV in advanced, uncommon applications and from utilities' increasing ability to capture the benefits of mass-market smart inverters.

Input: The utilities shall use a value of zero for this element.

1. Method.

In Order No. 17-357, the Commission invited Renewable NW and other parties to discuss how smart inverters could be valued in a future version of the RVOS Methodology.[36] The Commission noted, however, that it did not intend to assign a value to the grid services elements prior to the end of Phase II.

III. Other issues.

A. Real vs. nominal value.

The RVOS Methodology created by E3 contemplates that utilities will produce values in real levelized dollars. PacifiCorp's initial filing showed values in nominal levelized dollars. Staff believes that presenting the values in both real and nominal levelized dollars would provide additional clarity. Accordingly, Staff recommends that the Commission require utilities to include RVOS values in both nominal levelized and real levelized dollars in future RVOS filings. The nominal levelized values should be based on the inflation assumptions used by the utilities in their IRPs.

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[35] Order No. 17-357, p. 13.
[36] Order No. 17-357, p. 16.

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B. Frequency of updates to RVOS values

Given the reliance on data from the utilities' acknowledged IRPs and standard avoided costs, Staff contemplates that utilities should update the RVOS calculation consistently with the updates to standard avoided cost prices post IRP acknowledgment. Subsequent to the initial RVOS filings in late 2017, the Commission acknowledged each utility's IRP, so RVOS filings based on the Commission order in these dockets will use updated inputs from those IRPs.

IV. Staff recommendations.

The following is a list of Staff's recommendations to the Phase I Methodology. Staff anticipates future modifications to the Methodology based on Staff and stakeholders' continued investigation that will supersede some of these recommendations. In the meantime, however, Staff's modifications will help to provide transparency and predictability to the determination of RVOS.

A. Recommendations for Phase I Methodology.

Element	Recommendation
Energy	Utilities must use same source for forward price curve as used for standard avoided cost prices
Energy	Utilities must use most recently available forward price curve.
Energy	For 12 x 24 shape, utilities must rely at least in part on information from an economic dispatch model.
Generation Capacity	The CTP used to determine the value for generation capacity should be the CTP of an Oregon solar resource taken from the utility's most recently acknowledged IRP.
T&D Capacity	The distribution capacity value should be based on a recent or relatively recent MCOS, or if a MCOS is not available, the National Economic Research Associates (NERA) regression method.
T&D Capacity	The transmission capacity value should be based on an estimate of the firm transmission service that could be avoided due to distributed solar generation and the cost of that firm transmission service.
Integration	The integration study used to produce the integration cost value shall have sufficient information to allow utilities and stakeholders to at least extrapolate the cost to integrate solar resources.

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Market price response	The market price response value must not be incorporated into RVOS as an outboard adjustment.

B. Recommendations regarding utility compliance.

Many of Staff's concerns regarding utility compliance with the Phase I Methodology serve as the rationale underlying Staff's proposed modifications. Accordingly, if the Commission modifies the Methodology, the issues with utility compliance should be resolved.

Even if Staff's proposed changes to the Methodology are adopted, some of the compliance issues identified in Staff testimony will remain. With respect to compliance with the Phase I Methodology, Staff recommends that the Commission direct PacifiCorp to modify how it determines the environmental compliance element. Staff also recommends that the Commission direct Idaho Power to modify its calculation of the values for (1) administration costs, (2) market price response to account for solar development in other service territories as well as its own; (3) environmental compliance.

DATED this 26th day of July 2018.

Respectfully submitted,

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ATTACHMENT

to the state and/or federal tax codes that change the net cost of wind or solar to a utility off-taker.

Q. How is utility data used to calculate these hourly avoided costs?

A. The methodology described here, and the accompanying RVOS Model, directly translate hourly data on individual avoided cost elements into an hourly avoided cost profile for each year of the economic lifetime of the PV system. This methodology can be thought of as an accounting framework that is entirely reliant on data provided by the utilities. This is important to ensure that the RVOS calculated here is consistent with values used by the utility in other regulatory proceedings. For the purpose of this testimony, I have used placeholder data to calculate a sample range of RVOS estimates.

Q. Why is hourly data used as the basis for the RVOS?

A. It is the most granular level of data that is readily available from utilities and practicable for use in a spreadsheet model. Hourly values are able to capture the changing value of solar across the day and the calendar year as energy and capacity becomes more or less expensive depending on load levels and other factors. In cases where utilities do not have hourly values, a single value can be duplicated over many hours. For instance, for the sample utility I have used energy values for heavy-load hours (HLH) and light-load hours (LLH),[11] rather than unique values for every hour. Hourly values can be aggregated after-the-fact into longer timeframes such as seasonal or time-of-day periods.

[11] HLH consists of 6 AM – 10 PM, Monday through Saturday, excluding North American Electric Reliability Council holidays; LLH consists of all other hours.

Q. Can you please explain the methodology to calculate the hourly avoided cost value of each of these elements?

A. Yes. Table 3 explains the calculation methodology for each element that I list above. In all cases, the RVOS Model that I have provided contains working examples of these calculations and is a useful supplement for understanding the methodology.

Table 3: Element Avoided Cost Calculation Methodology

Line	Element	Calculation Methodology
1	Energy	Hourly marginal cost of energy including fuel (and associated fuel transportation costs), variable operations and maintenance, labor, and all other variable costs. $\forall h \in [1, \ldots, 8760]$ Energy_h
2	Generation Capacity	Annual carrying cost of new generation capacity ($/MW-yr) allocated to hours of the year using hourly normalized capacity value allocators. The allocators represent an hourly system need profile (based on loss of load probability (LOLP) or another method), multiplied by the modeled hourly solar generation, and scaled so that the allocators sum to one across the hours of the year. Annual carrying cost of new generation capacity ($/MW-yr) is defined as net cost of new entry (net CONE). Net CONE is calculated as the levelized carrying cost of a capacity resource – the levelized fixed cost of the resource (likely a new simple cycle combustion turbine (SCCT)) minus expected revenues that resource could earn through market dispatch. In the near-term years when the utility is not in a period of resource deficiency, a value of zero is used since there are no deferrable capacity investments. Solar's contribution to peak is a technical concept that captures solar's ability to serve peak loads. Through OPUC Docket UM 1719, the utilities have worked to develop a methodology for calculating this value. Many utilities across the country use a metric called effective load carrying capability (ELCC) to calculate the contribution to peak. The hourly capacity allocators (net

		CONE, allocated using LOLP) are scaled to ensure that the final generation capacity value of solar results are consistent with the utility-estimated solar contribution to peak. $\forall h \in [1, \ldots, 8760]$ $\text{GenerationCapacity}_h = \text{CapVal} * \text{LOLP}_h * \frac{\text{CTP}}{\text{SolarLOLPCoincidence}}$ where: CapVal = annual carrying cost of CT (\$/MW-yr) – expected energy market revenues (\$/MW-yr) in years of resource deficiency and fixed operations & maintenance (\$/MW-yr) in years of resource sufficiency LOLP_h = hourly loss of load probability allocators $\sum_{h=1}^{8760} \text{LOLP}_h = 1$ CTP = 'Contribution to Peak' (%) calculated through separate analysis $\text{SolarLOLPCoincidence} = \frac{\sum_{h=1}^{8760} \text{LOLP}_h * \text{SolarGeneration}_h}{\sum_{h=1}^{8760} \text{SolarGeneration}_h}$
3	Line Losses	Hourly marginal T&D loss factors multiplied to corresponding avoided cost of energy. For generation capacity and transmission & distribution capacity, these values are grossed up based on peak marginal T&D loss factors. $\forall h \in [1, \ldots, 8760]$ $\text{LineLosses}_h = \text{Energy}_h * \text{LossFactor}_h$
4	Transmission & Distribution Capacity	Marginal cost of transmission and distribution (\$/MW-yr) allocated to hours of the year using transmission and distribution specific hourly profiles (perhaps based on LOLP). $\forall h \in [1, \ldots, 8760]$ $\text{T\&DCapacity}_h = \text{T\&Dcost} * \text{T\&DLOLP}_h$ where: T&Dcost = marginal cost of T&D (\$/MW-yr) $\text{T\&DLOLP}_h$ = T&D hourly loss of load probability allocators

		$$\sum_{h=1}^{8760} \mathrm{T\&DLOLP}_h = 1$$
5	RPS Compliance	The net incremental cost of a renewable resource multiplied by the RPS requirement. The net incremental cost of a renewable resource is calculated as the levelized cost of the marginal renewable resource minus its energy value, generation capacity value, and avoided emission value plus the integration and transmission costs of that resource. The RPS requirement (%) is incorporated since this represents the quantity of RPS purchases that are avoided for every unit of solar generation. $$\begin{aligned}\mathrm{RPS\ Compliance}_h = (\ &\mathrm{RPS\ Price}\\ &-\mathrm{RPS\ Energy\ Value}\\ &-\mathrm{RPS\ Capacity\ Value}\\ &-\mathrm{RPS\ Emission\ Value}\\ &+\mathrm{RPS\ Integration\ Cost}) * \mathrm{RPS\ \%}\end{aligned}$$ where: RPS price = levelized power purchase agreement (PPA) cost of marginal RPS resource ($/MWh) $$\mathrm{RPS\ Energy\ Value} = \frac{\sum_{h=1}^{8760} \mathrm{Energy}_h * \mathrm{RPSGeneration}_h}{\sum_{h=1}^{8760} \mathrm{RPSGeneration}_h}$$ $$\mathrm{RPS\ Capacity\ Value} = \frac{\mathrm{CapVal} * \mathrm{RPS\ CTP}}{\sum_{h=1}^{8760} \mathrm{RPSGeneration}_h}$$ $$\mathrm{RPS\ Emission\ Value} = \frac{\mathrm{EmissionCost} * \mathrm{EmissionRate}_h * \mathrm{RPSGeneration}_h}{\sum_{h=1}^{8760} \mathrm{RPSGeneration}_h}$$ RPS Integration Cost ($/MWh) is calculated exogenously RPS % is the RPS requirement defined as a % of retail sales
6	Integration and Ancillary Services	$/MWh value provided by utilities that represents the net incremental cost of providing additional operating reserves, balancing services, and system operations required to integrate the solar resource.

7	Administration	$/MWh value provided by utility that represents the cost of interconnecting solar generators and any ongoing administrative costs such as billing. This value is uniform across all hours of the year.
8	Market Price Response	Estimated impact on Mid-Columbia price under a specified solar penetration ($/MWh) multiplied by utility net market purchases or sales (MWh). This total $ amount is then allocated to all solar generation (MWh) to yield a final $/MWh avoided cost value which is allocated equally to all hours. $\text{Market Price Response} = \frac{\Delta\ \text{Market Price} * \text{Utility Net Short (Long)}}{\text{SolarGeneration}}$ where: Δ Market Price = change in Mid-Columbia market price ($/MWh) due to solar Utility Net Short (Long) = the annual net sales or purchases (MWh) that each utility transacts at Mid-Columbia Solar Generation = total quantity of annual solar generation (MWh), note this quantity must be consistent with the quantity assumed to create the Δ Market Price
9	Hedge Value	Fixed % multiplied by the avoided cost of energy that represents the cost of utility hedging that is not already included in the energy value estimate described above. $\text{Hedge}_h = \text{Energy}_h * \%$
10	Environmental Compliance	Hourly marginal emission factor of carbon dioxide multiplied by the monetary cost of carbon dioxide. $\text{Environmental Compliance}_h = \text{EmissionFactor}_h * \text{EmissionCost}$ where: EmissionFactor_h = hourly marginal emission factor (tonne CO2 per kWh) EmissionCost = compliance cost of CO2 emissions ($ per tonne)

Q. How do you translate these hourly avoided costs into an RVOS?

A. The 8760 hourly avoided cost profile is multiplied by the 8760 hourly solar generation profile, and then divided by the total annual solar generation to yield an annual average RVOS.

$$\mathrm{ResourceValueOfSolar} = \frac{\sum_{h=1}^{8760}(\mathrm{Value}_h * \mathrm{SolarGeneration}_h)}{\sum_{h=1}^{8760}\mathrm{SolarGeneration}_h}$$

Q. For how many locations and types of solar can the model calculate an RVOS?

A. As currently configured, the model calculates the value of one type of solar at a single location. However, the model can be used to value the generation of any type of solar resource at any location, provided the correct data is input into the model. Different locational solar values can be calculated through successive model runs, substituting location-specific inputs such as distribution avoided costs. Additionally, the RVOS for different types of PV systems such as residential or commercial can be calculated through successive model runs with different solar generation profiles.

Q. For how many locations and types of solar should a separate RVOS be calculated?

A. The answer depends on the purpose for which the RVOS is calculated. In theory, a separate RVOS could be calculated for every distribution system feeder or substation in the state. However, this would require hundreds or even thousands of model runs to establish these highly-granular, location-specific values. Alternatively, a single RVOS could be calculated for each