ORDER NO. 19-022

ENTERED Jan 22, 2019

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1911

In the Matter of IDAHO POWER COMPANY, Resource Value of Solar.	ORDER

DISPOSITION: VALUES ADOPTED

I. INTRODUCTION

In this order, we complete Phase II of the resource value of solar (RVOS) proceeding, and adopt the final methodologies that Idaho Power Company (Idaho Power) will use to produce its initial set of RVOS values. We direct Idaho Power to develop revised RVOS calculations consistent with this order, and file them in this docket by March 18, 2019. We also direct Idaho Power to file additional information regarding avoided transmission and distribution, generation capacity, and line loss values no later than July 18, 2019. We make similar determinations for Portland General Electric Company (PGE) and PacifiCorp, dba Pacific Power, in separate orders.

The long-running goal of this docket has been to establish a framework to express the quantifiable costs and benefits of bringing solar resources to the utility system. With this order, we advance that goal in a context of significant industry and technology change. Options for customer and community engagement in energy solutions continue to increase, technology advancement continues to support this change, and the policy landscape continues to evolve. In this context, our framework should increasingly guide customers and communities toward energy choices that make positive contributions to the reliable, high quality and affordable system that all customers deserve.

Accordingly, in this decision, we have favored increasingly granular expressions of resource value, along with improved techniques for valuing resource benefits that have not previously been quantified. Evolving our approach to expressing the value of solar will enable us to transparently credit the unique contributions of solar projects in different locations and with different characteristics, and also creates a foundation for valuing contributions from new technologies such as associated storage. We recognize that increasing complexity of valuation may require more work to implement and provide customer education, and that it will take time to move in this direction. We have sought to create an RVOS framework that is meaningful and workable today, while setting an expectation that the framework will continue to improve.

Our decision establishes a methodological framework from which utilities can produce an initial set of RVOS values. We do not address application to or implementation within any particular program, although we make occasional references to the Senate Bill (SB) 1547 community solar program.[1] We observe that this decision sets values for resource attributes common to many programs in which customer and community-based resources connect with the system. With such programs proliferating, we will be looking for ways to improve the consistency and efficiency of valuing equivalent contributions across programs, while recognizing that different programs may still warrant different implementation approaches.

II. BACKGROUND

This docket has had a lengthy history. We first considered developing a calculated RVOS as part of the Solar Volumetric Incentive Pilot Program.[2] In a July 2015 report to the legislature, we committed to open an investigation to determine a calculated RVOS. The investigation began with a Staff proposal that identified 26 value of solar elements for consideration.

Through Order No. 15-296, we established a two-phase process to adopt RVOS values for individual electric companies. The first phase would examine elements and methodologies. The second phase would examine values for each utility using those adopted methodologies. At the same time, we authorized Staff to engage a consultant to support an initial framework and RVOS proposal. Reflecting our legislative mandate, we indicated that we would "only consider elements that could directly impact the cost of service to utility customers. For example, we would consider the potential financial costs to utilities of future carbon regulation. On the other hand, for example, we will not consider job impacts of solar development."[3]

Subsequently, Staff retained a consultant, Energy and Environmental Economics, Inc. (E3), to assist in development of an RVOS framework. Phase I activities continued for more than a year, and we asked that parties narrow issues and address specific questions in Order No. 16-404. In Order No. 17-085, we directed parties and utilities to address a straw proposal outlined by Staff and E3.

Through Order No. 17-357, we modified and adopted the straw proposal for RVOS elements, closed Phase I of the RVOS proceeding, and ordered utilities to file individual

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[1] *See* ORS 757.386 (6) (a) and (b). In SB 1547, the legislature specifically requires that electric companies credit community solar participants "in a manner that reflects the resource value of solar energy" unless we have "good cause to adopt [a] different rate."

[2] *In the Matter of Public Utility Commission of Oregon, Investigation into the Appropriate Calculation of Resource Value for Solar Photovoltaic (PV) Systems*, Docket No. UM 1559.

[3] *In the Matter of Public Utility Commission of Oregon, Investigation to Determine the Resource Value of Solar*, Docket No. UM 1716, Order No. 15-296 at 2 (Sep 28, 2015).

levelized RVOS values for a generic, small-scale solar resource installed in 2017. In that comprehensive order, we largely adopted the methodology proposed by E3.

Our Order No. 17-357 included the following value/cost elements:

- Energy, Generation Capacity, Transmission and Distribution Capacity and Line Losses. We indicated that these elements would largely come from utilities' existing avoided cost prices, and existing cost studies. We noted that additional granularity could properly value the shape of solar production.

- Integration and Administration. For these costs to the utility, we ordered that the utilities use existing integration studies for the first, and provide a narrative explanation of administrative cost proposals for the latter.

- Market Price Response and Hedge Value. We ordered that these values be set according to the proxy values proposed by E3.

- Environmental Compliance. We reserved this value for consideration in the second phase of review.

- RPS Compliance and Grid Services. Both values were set at zero, but we invited proposals to consider methodologies. We stated that we would adopt a methodology for RPS compliance in Phase II, but not grid services.

In this second phase of the proceeding, utilities filed formal proposals for individual RVOS values. Parties filed two rounds of testimony in response, and on June 25, 2018, we conducted a Commission examination. Briefing concluded on August 9, 2018.

III. DISCUSSION

This decision resolves all methodological questions for each element, and provides instructions to Idaho Power for finalizing values where we have not accepted Idaho Power's proposal for an element. In testimony, several parties including the Oregon Solar Energy Industry Alliance (OSEIA) and Staff argued for greater granularity of values in order to more accurately assess the benefits of solar to the system. This order embraces and amplifies those requests. A unifying theme of this decision is a definitive movement away from assuming the performance of resources based on generic characteristics, and a move towards describing system needs and valuing specific resources' contributions to meeting those system needs.

For the short term, we do retain the requirement that utilities provide both a real levelized and nominal levelized price expression based on a generic resource. Providing a simplified value more promptly, with the first round of updated values required by this order, will give interested parties an early indication of the likely RVOS outcome for a generic solar resource.

The second round of updated values required by this order, however, will begin to evolve the RVOS to reveal the system value of individual resources rather than the levelized, estimated life-time value of a generic resource configuration (e.g. east-side fixed-tilt solar). Such value is time and location dependent in many cases. As we make this transition from a generic resource value to a system value for services provided by individual projects, we take an initial step by asking utilities to provide energy, generation capacity, line losses and T&D capacity values on a 12 x 24 basis, where the values are not shaped to the performance of generic solar shape but expressed according to system need.

Importantly, both rounds of updates should be made using the latest applicable Commission-approved values for all RVOS components, such as market prices or capacity sufficiency and deficiency dates.

The pricing for these elements should reflect hourly technology-neutral value to the system rather than levelized annual or life-time value via assumed solar performance. This pricing expression will better communicate system needs, and will encourage, where feasible, projects to include elements that would increase project revenue by better meeting those system needs. For example, if energy deliveries to the system are more valuable in the early evening on a particular day, shortly after sunset, a solar developer might consider or model the cost of an associated storage project to accompany the project. We find that pricing should provide these types of signals, so that development patterns begin to align more closely to the needs of the system. In turn, development patterns that align with system value enable sustainable, long-term growth in customer resource choice.

We emphasize that the 12 x 24 value requirement is at this stage limited to the calculation of RVOS values, and in this order we make no decisions or determinations regarding how this price expression will be used or implemented in programs for which RVOS is employed. Those implementation questions will be addressed exclusively in individual program dockets, and we will carefully review the complexity associated with the application of a 12 x 24 value expression. In this review, we will be sensitive to technical questions associated with the use of a 12 x 24 value expression, program participants' tolerance for complexity, and prudential issues such as the functional capability of individual utility systems.

We recognize that it will take time to refine these values, improve existing tools, and develop new tools to the point where the RVOS is truly reflective of hourly and eventually location-based system needs. We intend for our decision to set a direction and foster continuous improvement, so that while 12 x 24 hourly blocks may initially be rudimentary indicators of system need, they will improve over time to better reflect those needs. Similarly, where we request new values, such as locational values for transmission and distribution (T&D) capacity deferrals, we understand that the development and refinement of the values will take time and likely several iterations.

Accordingly, we expect to work with utilities and stakeholders to review ideas and approaches to compliance with this decision, through individual RVOS dockets and other investigations. Ultimately, the RVOS will be used for economic decision making. To the extent possible, the tools used to define individual elements such as the 12 x 24 generation capacity and T&D capacity deferral values and spread should be clear and transparent. Customers and developers will act according to these price signals, and should be able to understand their origins.

Finally, we note our desire to see more uniformity across applications for avoided costs. This contributed to our decision to limit changes to the methodologies for calculating energy and generation capacity values, for example. Avoided cost methodologies for these elements were already established through our implementation of the Public Utility Regulatory Policies Act (PURPA), and we have a preference for consistency in pricing core elements across programs and technologies. Until such time as we change the foundational methods for developing those core avoided costs, we are likely to mirror the methodology that we use for PURPA avoided costs in RVOS.

Below, we review each element in turn, describing our past determinations on methodology, reviewing Idaho Power's application of that methodology, discussing party proposals and reactions, and describing our resolution. Where appropriate, we issue additional direction to Idaho Power. The following table summarizes our decision on an element-by-element basis:

Element	**Determination**
Energy	Idaho Power's approach adopted, with the following changes: Idaho Power is ordered to use uncapped EIM data for price shaping. 12 x 24 expression of value required.
Generation Capacity	Idaho Power's standard PURPA approach adopted, but pricing must be shaped across 12 x 24 blocks to express temporal value of system generation capacity need, rather than levelized and spread equally over estimated total solar generation.
T&D Capacity Deferral	Staff's recommendation is adopted. Idaho Power should use its latest Marginal Cost of Service Study for calculating T&D Capacity deferral. Idaho Power should shape this value over 12 x 24 blocks to express temporal value of system T&D capacity need. Idaho Power is ordered to begin development of rudimentary locational pricing that will begin to identify areas with high, average, and low T&D capacity deferral value relative to the system average value.
Line Losses	Idaho Power's values and approach adopted. Idaho Power should express these values in 12 x 24 blocks rather than levelized via solar performance assumptions.

Integration	Idaho Power's value adopted.
Administration	Staff's recommendation adopted as a proxy; value to be developed consistent with individual program implementation costs.
Market Price Response	Idaho Power is ordered to use E3's price elasticity model, in the middle of the E3 provided range at -0.0015%. This approach should take into account the short or long positions of Idaho Power.
Hedge Value	Idaho Power's value adopted.
Environmental Compliance	Idaho Power's value adopted as a proxy; value to be developed according to individual program implementation needs.
RPS Compliance	Staff's recommendation adopted.
Grid Services	Idaho Power's value is adopted, until such time as additional investigation identifies grid service benefits.

We have established time frames for utilities and stakeholders to address our order and value expression requests. For most of our requested updates, we order Idaho Power to file revised values with supporting materials in this docket no later than two months from the date of this order. For the following items—T&D capacity deferral 12 x 24 blocks, T&D capacity deferral locational zones, line loss 12 x 24 blocks, and generation capacity 12 x 24 blocks—we order that Idaho Power file revised values with supporting material in this docket no later than six months from the date of this order.

IV. DISCUSSION

A. Avoided Energy

1. Methodology Review

In the first phase of this proceeding, we considered the straw proposal for avoided energy methodology developed by Staff and E3. For calculating energy value, the straw proposal described a method by which utilities would use current QF avoided cost pricing. QF pricing is published in monthly or annual on- and off-peak blocks. The straw proposal suggested that Staff convene workshops to examine the need for and costs of modeling to estimate energy value at a more granular time interval.

E3 argued that hourly pricing was superior to less granular pricing for several reasons. First, E3 anticipates that hourly pricing will produce higher RVOS values today, due to partial correlation between solar production and periods of higher pricing. E3 derived this conclusion from review of PacifiCorp's confidential hourly pricing models.

Second, E3 preferred the more granular values because they can be adjusted directionally reflecting the evolving impact of more solar moving to the system. Today, solar may provide energy at times where energy is more valuable than the mean. However, as more solar is added to the system, this trend may reverse. If it does, an RVOS with more granular pricing can be adjusted to reflect this reality. E3 noted that in California, solar penetrations have increased to such a point that hourly data actually decreases the value of the energy RVOS element by approximately 10 percent. E3 expects a similar change to occur in Oregon over time, as penetrations of utility-scale and behind-the-meter solar increase. E3 argued that the utilities are well equipped to create this hourly granularity, as utilities create hourly tools in the course of regular planning exercises.

E3 also suggested that hydro variability is an important factor in the development of energy values. E3 estimates that hydro variability does not have symmetrical effects on prices, and that the impact of a particularly wet year for lower prices is not nearly as significant as the impact of a particularly dry year for higher prices. E3 recommended that utilities take this asymmetry into account when developing energy pricing.

In Order No. 17-357, we indicated a strong desire for more granular energy values over time:

> We modify the straw proposal to require more granular energy values to advance the idea that RVOS values should have a price shape. We direct the utilities to use a 12 x 24 block for energy prices, and to include a detailed explanation of how they created the 12 x 24 block. Our expectation is that, for each 12 months in a year, utilities would develop a typical day shape of prices across 24 hours from the same pricing source used to develop their average monthly or annual on and off-peak standard QF energy values. We require this more granular approach because we agree with parties that a daily shape is important for solar compensation. We intend to move toward accuracy and granularity over time as penetration increases, and believe that a 12 x 24 block is a reasonable compromise that achieves a level of detail while addressing the utilities' concerns over confidentiality and administrative burden.[4]

Although we adopted E3's recommendations on granularity, we also gave utilities some freedom in developing these values as long as they produced an hourly price shape, and required that they explain in detail their methodologies. We did not resolve the hydro variability issue highlighted by E3.

[4] *In re PUC Investigation to Determine RVOS*, Docket No. UM 1716, Order No. 17-357 at 4 (Sep 15, 2017).

2. Idaho Power's Application of the Energy Value Methodology

Idaho Power used market prices utilized for its standard avoided cost prices, used for PURPA compliance and applied a price shape factor of one, resulting in a flat shape applied to the energy value.

To develop an hourly shape, Idaho Power used the hourly capacity output from its Oregon PV pilot and multiplied this by published avoided costs for solar energy. Idaho Power's calculation shapes the solar output, but not the pricing.

3. Party Positions

OSEIA argues that all utilities should use PacifiCorp's approach, with uncapped EIM data. OSEIA's expert stated that he saw "no reason to cap artificially the actual EIM prices paid by willing buyers and sellers in this broad regional market."[5]

Staff proposes changes to the utility methodologies to incorporate more potential variation in hydro production. The utilities generally oppose Staff's approach, arguing that it adds complication and that the differences in Staff's approach and the preferred individual utility approaches was not material. At the Commissioner examination, Staff stated that it no longer intended to pursue its recommendations on hydro conditions and energy values. We asked utilities if the difference between Staff's approach to hydro variability and their own created a substantive difference in energy prices. The answer was negative.

4. Resolution

We adopt PacifiCorp's approach for all utilities, and require use of uncapped EIM data to allocate the energy value (i.e. the financial value) across 12 x 24 blocks. We also require use of three years of EIM data, where such data is available. We determine that hourly granularity will provide the best reflection of the value of the solar energy resource to the system. Those hourly values should produce pricing throughout the year that is reflective of real, observed market conditions and adapts readily to the rapidly evolving generation resource mix. Currently, the EIM is the best tool yet identified to reflect market conditions. Specifically, there is robust regional participation in the EIM, which allows greater insight into broad trends in marginal hourly value. If an hourly need is consistent across the region and reflected in EIM values, a solar facility responding to the need is likely providing vital system support.

We agree with OSEIA that it is appropriate to use uncapped EIM data for two reasons. First, EIM pricing is already capped by the EIM itself. Second, uncapped values provide a more accurate reflection of actual market conditions. We require the use of three years of EIM data because this is more likely to present a picture of price fluctuation that reflects consistent trends than will only one year of data. Where three years of data is not

[5] OSEIA/100, Beach/5.

available, utilities are permitted to use less. We agree with Staff and the utilities that hydro variability need not be accounted for according to Staff's proposed approach.

B. Generation Capacity

1. Methodology Review

In Order No. 17-357, we largely adopted the straw proposal for the generation capacity value. In our resolution of the issue, we stated that "Adopting our current QF practice is most efficient for the first version of the RVOS, and appropriately values the capacity acquisition that is avoided by the utility due to solar PV."[6] The straw proposal approach directs the utilities to determine the marginal avoided costs of capacity consistent with PURPA avoided cost guidelines.

E3 had proposed a change to the straw proposal, which we did not adopt in Order No. 17-357. Specifically, E3 recommended that avoided O&M costs be assigned as a generation capacity value during the sufficiency period; because existing capacity resources would have to ramp up less to meet peak capacity needs due to the operation of solar resources.

Our order explained that during the sufficiency years, utilities use forward market prices to calculate avoided cost price, which embeds the value of incremental capacity in the total market-based avoided cost rate. For deficiency years, the utility multiplies the contribution to peak of a resource type by the capacity cost of the utility's avoided proxy resource.

Although we did not adopt E3's proposal for the inclusion of O&M costs during the sufficiency period, we did request that a workshop be convened to discuss this and other proposals, including:

- Allowing the full capacity value up to a reasonable number of years before the deficiency year (*e.g.*, three or four years) as recognition that it takes time to ramp up infrastructure to avoid a major resource.
- Any other ideas arising from related Commission dockets or those raised by the parties.

This workshop has not been held, though parties have discussed such concepts in testimony and briefing.

2. Idaho Power's Application of the Generation Capacity Methodology

Idaho Power derived avoided cost prices using its QF avoided cost approach, and utilized the deficiency date from the acknowledged 2017 IRP. Idaho Power shaped the generation capacity value according to assumed solar performance.

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

3. Party Positions

OSEIA argues that the shorter lead times and smaller capacity increments that distributed solar resources provide to the system mean that "the suggestion of Order No. 17-357 to advance by up to four years the 'resource balance year' when each of the IOUs will need capacity"[7] should be adopted. OSEIA contends that this proposal is rooted in the Federal Energy Regulatory Commission (FERC) PURPA regulations, "which explicitly state that avoided cost rates for purchases from QFs must take into account 'the smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities.'"[8]

OSEIA suggests that generators be compensated for marginal O&M costs in periods of resource sufficiency, and that the deficiency period be moved up in consideration of the lumpy nature of major resource additions. E3 also supported this understanding of capacity value in its early work on RVOS.

4. Resolution

Throughout our previous decisions on RVOS methodology, and as reflected in this order, we express a clear preference for more granular expression of values that limit or eliminate resource performance assumptions, and instead focus on system needs. Generation capacity values can be analyzed in this manner. Idaho Power's value assumes resource performance, then applies that performance to hour-by-hour generation capacity needs. We adopt Idaho Power's generation capacity values, derived from its currently approved approach to PURPA avoided cost development. However, we require that Idaho Power express those values in 12 x 24 blocks, which are not shaped by solar performance assumptions.

This expression should include a proposal to allocate the generation capacity value (*i.e.,* the financial value) across the 12 x 24 expression, explaining why value is concentrated at certain times, and the justifications associated with spread or ratio of the value across hours. Idaho Power should shape these values to reflect when avoided generation capacity is most useful to the system. We agree with OSEIA's preference for a more granular performance based value. Our decision puts the focus on system needs, allowing the generation provider to design and conceivably shape solar output to maximize utility payments, in a way that most benefits the system.

We decline to adopt OSEIA's proposal with regard to O&M. We remain interested in further exploration of this concept, and consider it a potential topic for future investigation, but do not advance it here for two reasons. First, we believe the proposal should be more thoroughly explored by parties and Staff, and do not believe there is sufficient support on the record to adopt it. Second, we have an interest in ensuring that avoided cost values are consistently reviewed and employed across applications. In our

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[7] OSEIA Opening Brief at 2 (Jul 26, 2018).
[8] OSEIA/100, Beach/6.

implementation of PURPA, we do not artificially advance the deficiency date based on the lag associated with the acquisition of large resources. Similarly, we do not provide value for O&M during the sufficiency period.

That noted, we determine that it is appropriate to begin to resolve universal capacity issues in a manner that is resource and program agnostic. Accordingly, we order that by April 23, 2019, Staff provide the Commission with a proposed scope for a general capacity investigation. This investigation will proceed in parallel with the resolution of outstanding issues in this and the other individual utility RVOS dockets. This investigation may inform how capacity value is calculated for the RVOS. It is our intention to harmonize the understanding of the value of capacity to individual utility systems through this investigation across all applications where capacity is relevant.

C. Transmission and Distribution Capacity

1. Methodology Review

Before we adopted a methodology for this element in Order No. 17-357, we considered the straw proposal. The straw proposal asked utilities to propose a system-wide average of avoided Transmission and Distribution (T&D) capacity attributable to incremental solar. The straw proposal specified that the avoided T&D capacity should be for growth-related investments. E3 disagreed slightly, stating that avoided or deferred T&D should be for all T&D upgrades, which will mostly be tied to load growth but not always. E3 derived its proxy values for transmission and distribution capacity deferral from Marginal Cost of Service Studies (MCOSS).[9] E3 observed that T&D costs can be calculated at the system average level or for more specific locations such as utility distribution planning areas or even distribution feeders.

Ultimately, we adopted the straw proposal approach, but recognized E3's emphasis on the deferral of all T&D upgrades. Subsequently we ordered that utilities should use a "system-wide average of the avoided or deferred costs of expanding, replacing, or upgrading T&D infrastructure to incremental solar penetration in Oregon Service areas."[10] We clarified that avoided costs need not be specifically limited to growth related-investment.

We also noted the past use of the MCOSS for this type of purpose: "We have long required utilities to estimate avoidable T&D costs by referencing their most recent studies used to set rates (Marginal Cost of Service Study) and the utilities may continue to use those studies for the first version of RVOS."[11] Historically, we have used the MCOSS to

[9] "In the absence of more specific values, I believe that the MCOSS provide a reasonable basis for these sample values." UM 1716, Staff/401, Olsen/22.
[10] Order No. 17-357 at 8-9.
[11] *Id.* at 9.

derive estimates for avoided transmission and distribution costs in other applications, such as the development of energy efficiency avoided cost values.[12]

2. Idaho Power's Application of the T&D Avoided Cost Methodology

Initially, Idaho Power calculated T&D Capacity using the deferral benefits it calculated for energy efficiency resources. Idaho Power later changed its approach, and used substation and transformer data to identify which locations would be capacity limited within 25 years, and then determined which capacity investments could be deferred by increased solar generation; then annualized that number.

3. Party Positions

Staff endorsed PGE's approach; which used its MCOSS to derive T&D deferral values. Staff recommends that all three utilities use PGE's method.

OSEIA argues that "[d]istributed solar that connects behind the meter or directly to the distribution system produce power that typically is consumed on that distribution system."[13] OSEIA states that behind-the-meter solar will serve 40 percent to 60 percent of load, thus reducing load on the T&D system. Exports on the grid are likely to be consumed by the customer's neighbors on the distribution level, OSEIA argues, and therefore will reduce transmission costs.

OSEIA accepts the use of the MCOSS for PGE, but recommends that Idaho Power use a regression analysis of load growth and distribution investment to calculate this value. This is a model developed by the National Economic Research Associates, and has been used by other utilities to determine long-run marginal distribution capacity costs that vary with load. OSEIA's proposal includes a 7.9 percent general plant adder, which addresses ongoing O&M expenses.

Ultimately, OSEIA contends that the T&D capacity costs avoided by solar should be determined on a locational basis, because load profiles on the T&D system and the need for capacity will differ based on location.

> The substation data shows that some distribution substations are closer to capacity than others, and solar DG (as well as other types of DERs) installed on those constrained parts of the distribution system will provide greater benefits than in other locations * * *. Thus, if DERs – including solar DG, storage, or energy efficiency programs – can be targeted to the parts of the system where they are most needed, i.e. where marginal distribution costs are the highest, they can produce significantly greater

[12] *See In The Matter of An Investigation Into The Calculation And Use of Conservation Cost-effectiveness Levels,* Docket No. UM 551, Order No. 94-590 at 5 (Apr 6, 1994).
[13] OSEIA/100, Beach/12.

benefits than what are estimated using a system-wide marginal distribution costs.[14]

4. Resolution

We adopt Staff's recommendation for this value. We find that the MCOSS methodology for calculating T&D capacity deferral, an approach that was endorsed by E3, is the most reasonable method for estimating T&D capacity value at this time. We agree with OSEIA that ultimately T&D capacity value is best expressed according to granular system needs, both with respect to time and location. Accordingly, we order that in expressing T&D capacity value, Idaho Power do so through 12 x 24 blocks that do not assume solar performance. Instead, this expression should include a proposal to allocate the T&D capacity value (i.e., the financial value) across the 12 x 24 expression, explaining why value is concentrated at certain times, and the justifications associated with spread or ratio of the value across hours. Idaho Power should shape these values to reflect when avoided T&D is most useful to the system, such as when T&D is most capacity constrained.

We also order Idaho Power to begin to work towards developing locational signals, as emphasized by OSEIA. Six months from the issuance of this order, Idaho Power should present us with a proposal that provides locational information on three classes of T&D capacity value: (1) areas where there is a heightened T&D Capacity value; (2) areas where there is an average value; and (3) areas where there is a lower value. We direct Idaho Power to work with Staff in developing this proposal. We understand that utilities may be at different places in their ability to provide these locational indicators, and may produce fundamentally different results. We consider this to be reasonable at an early stage in the development of locational value. Finally, we counsel Idaho Power to focus its efforts regarding the locational value to its Oregon service territory, as this value will be used in Oregon programs and will be most informative to stakeholders and developers in Oregon.

Our decision relies on the MCOSS, because it serves as a foundation to our ratemaking process and is designed for allocating and assigning costs across all customers. The MCOSS is a ratemaking tool that examines all elements of providing service, and assigns an average cost allocating each service element to each unit of energy delivered. The performer of the study looks at a broad spectrum of billing determinants and other units and can observe how adding one more unit changes costs, and this provides a value or relative impact per unit for each of these types of units.

Accordingly, the MCOSS represents a shared understanding of system costs associated with each unit of energy produced and delivered, and allows the isolation of individual components to identify the cost or value associated with different actions. These values are generalized, averaged values – meaning that they are representative of costs and risks

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[14] *Id.* at 20.

to the overall system, but not a specific action. Historically, it has been used to derive avoided costs for T&D capacity, and other avoided cost elements.

We emphasize that T&D capacity value is location-dependent; as a result, a uniform value applied equally across one service territory will inevitably overcompensate some projects and undercompensate others. A distributed solar project located in an optimal area—*i.e.*, one with constraints—will likely be undercompensated for T&D deferral under any methodology that offers a uniform value. Conversely, a uniform value would likely overcompensate a project that locates in an area facing a major load decline. Because we want to encourage resource development in locations that provide system benefits, we emphasize the need to continue to improve the locational granularity of this value.

We expect this methodology to improve over time. The first expression is likely to be crude, because electric companies have yet to develop the tools necessary to fully capture this value, particularly with regard to locational signals. Accordingly, we will welcome updates, improvements, and methodological suggestions as we continue to implement the expression of this value going forward. Ultimately, we believe that the T&D capacity value could be a very important price signal that indicates system need and is actively used to encourage project siting in line with system needs, leading to more efficient and beneficial development.

D. Line Losses

1. Methodology Review

In Order No. 17-357, we adopted a methodology that would require utilities to develop hourly averages of line losses by month for the daytime hours when load on the system is higher, losses are greater, and solar is generating. We required that these values reflect seasonal and daily variations in line loss impacts with higher temperatures and higher loads having higher losses. As with other elements, we asked for a high level of granularity, if feasible. We asked "the utilities to explain how they reflect daily and seasonal variation in their marginal line losses calculation."[15] In the course of the development of this methodology, E3 argued that marginal line losses will be greater than average losses because line losses increase non-linearly with system load, and requested that the utilities develop hourly data, as well as seasonal data.

2. Idaho Power's Application of the Line Loss Methodology

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

[15] Order No. 17-357 at 2.

3. Party Positions

OSEIA proposes higher values for the line loss element. OSEIA's expert asserts that "the use of average losses fails to capture the fact that the reductions in line losses on the margin, from small changes in load on the system, are significantly greater than average losses."[16] OSEIA's expert derived alternative values by increasing "the average loss factors used by the utilities by 50% to capture the higher marginal losses avoided by solar DG resources, based on a study from the Regulatory Assistance Project (RAP) on the relationship between average and marginal line losses avoided by distributed energy resources such as energy efficiency and solar DG."[17] Staff opposes OSEIA's proposed change to the methodology, and notes that utilities provided values that represent estimates of seasonal and within-day changes.

4. Resolution

Idaho Power complied with our direction from Order No. 17-357. We adopt Idaho Power's values for line losses, and, consistent with the decisions above, require that Idaho Power express these values in 12 x 24 blocks. We request that electric companies work to improve this methodology in future filings. We decline to adopt OSEIA's proposal because it may result in values that do not correspond well to demonstrated system needs, at peak load times.

E. Integration

1. Methodology Review, Application, and Party Positions

The integration element is described as the costs of a utility holding additional reserves in order to accommodate unforeseen fluctuations in system net loads due to the addition of renewable energy resources. No party has objected to Idaho Power's proposed integration cost estimates.

2. Resolution

We find that Idaho Power has developed its integration cost value consistent with our direction and order no changes.

F. Administration

1. Methodology Review

Our administration cost methodology adopted in Order No. 17-357 gives the utilities wide flexibility to propose administration cost values for the RVOS; determined as "direct, increased utility costs of administering PV program * * *."[18] E3 argued that the Administration component should only be intended to capture costs that are both

[16] OSEIA/100, Beach/25-26.
[17] *Id*.
[18] Order No. 17-357 at 10.

incremental to what the utility incurs for any other account, and incremental to any portion of the cost paid by the solar generator.

2. Idaho Power Application of the Methodology and Party Positions

Idaho Power used the actual costs incurred for the Oregon PV Pilot in 2016 as its basis for this element, the result was an administration cost that erased all positive value in the Idaho Power RVOS.[19] Staff and other parties object to this approach. Staff recommends Idaho Power use the incremental costs of administering net metering or similar programs.[20]

Idaho Power argues that using actual data from operating programs is the only appropriate way to estimate the value at this time.[21] In rejecting Staff's suggestion, Idaho Power emphasizes that "Staff does not explain why it believes that the actual costs Idaho Power incurred administering a pilot solar program in Oregon do not accurately reflect the likely costs of administering future solar programs."[22] OSEIA suggests the use of PacifiCorp's value for Idaho Power.[23]

3. Resolution

We adopt Staff's recommendation and order Idaho Power to develop its initial value consistent with net metering administrative costs, but this value will act as a proxy only. We order that Idaho Power update this value on a program by program basis. Accordingly, as Idaho Power acts to utilize the RVOS for implementation in a program, Idaho Power must develop a program specific administration cost, unique to the program for which the RVOS will be applied. The process and content of this value should be reviewed and developed in those individual program applications.

At this time, there is only one program for which the RVOS will be explicitly applied, and that is Community Solar. Accordingly, the value Idaho Power utilizes for RVOS application in the Community Solar program must reflect the anticipated costs of a Community Solar program, taking into account the attributes of the program in Oregon. This value will be inaccurate if based on a program with different administrative costs.

The Community Solar Program in Oregon will be unique nationally in its use of a third party administrator, which will take on many of the roles reserved for a coordinating utility in other jurisdictions. Under the currently proposed Oregon model, the utility will be responsible for these core activities:

- ensuring billing systems reflect output and charges associated with Community Solar participation for participating customers

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[19] Idaho Power/200, Haener/19-20.
[20] Staff/200, Andrus/10.
[21] Idaho Power Opening Brief at 11.
[22] Idaho Power Reply Brief at 6-7.
[23] OSEIA/100, Beach/27.

- remitting money collected from participants to the program administrator, or a third-party banking partner
- remitting data as requested to the third-party administrator, and
- contracting with, interconnecting, and tracking output of Community Solar projects.

One of these responsibilities must be addressed regardless of the program; i.e. the utility must contract, interconnect, and track the output of all resources. This means that the primary additive responsibility of the utility in the operation of a Community Solar program in Oregon will be billing related, and forwarding money and data. We do not consider any of the administrative cost proposals put forward by Idaho Power to be consistent with the actual expense Idaho Power is likely to incur in administration of the implantation of the Community Solar program. Staff's recommendation that Idaho Power base these charges off of net metering administrative cost values is a reasonable alternative for a proxy value. Idaho Power should be prepared to develop an administrative cost value based on actual anticipated administrative costs for each program in which the RVOS will be utilized, such as the Community Solar program.

G. Market Price Response

1. Methodology Review

For this element, we directed that E3's model create a proxy value for market price response be used by the utilities, and that utilities should not assume that this value is zero. We defined Market Price Response as "[t]he change in utility costs due to lower wholesale energy market prices caused by increased solar PV production."[24]

E3's methodology multiplies the change in wholesale prices by the size of the net short/long position of the utility, and divides this number by the solar generation that caused the change in wholesale prices. Deriving the magnitude of the potential price change is difficult, and E3 provided two proposals for estimating this value.

First, E3 proposed utilizing studies of western market impacts that estimate a price elasticity of -0.001 to -0.002 percent for each MWh of wind energy, measured for heavy load hours and light load hours.

Second, utilities would do sequential runs in a production simulation model, with a large enough increment of solar added to affect the calculated market price during each hour. The price differences would then be used to derive a market price elasticity per MWh of energy produced from customer-owned solar resources.

[24] Order No. 17-357, RVOS Proposal at 22.

In either case, the change in market price would be multiplied by the utility's net short or long position during each hour, creating a benefit if the utility is short and a cost if the utility is long.

We directed Staff to "coordinate or facilitate use of E3's model to create a proxy value for market price response that utilities will use in their initial RVOS filings."[25] We directly stated that utilities should not assume a value of zero unless "there is firm evidence that a value does not exist or that solar installations cannot contribute to it."[26] Finally, we noted that "[b]ecause we are hoping to have final RVOS values in less than one year, we believe it is most efficient and reasonable to use E3's model on increasing wind energy at Mid-C as a proxy for valuing market price response of incremental customer-owned solar PV."[27]

Staff observes that ultimately, the "impact on a utility depends on its position in wholesale markets. If it buys more [than] it sells (the utility is 'net long'), then a reduction in wholesale prices leads to a positive benefit toward the utility. If it sells more than it buys ('net short'), then this response will be negative."[28]

2. Idaho Power's Market Price Response Application and Party Positions

Idaho Power determined that it sold more energy to the market than it purchased, and hence used a negative market price elasticity. The Company uses 0.00 as the value of market price response in its RVOS filing. Staff disagrees with Idaho Power's approach, and states that "So long as the marginal cost of solar is below the market price of electricity…" market prices will be depressed.[29]

OSEIA recommends that all utilities should adopt PGE's approach to this value. PGE uses same monthly energy inputs as is used for wholesale market prices during the resource sufficiency period for its Schedule 201. Beyond 2030, PGE modeled values to 2050.

3. Resolution

To resolve the deficiencies associated with the development of this value, we order Idaho Power to adopt E3's proxy method, which we signaled we might require in Order No. 17-357, using the first of the two E3 options and setting the elasticity value in the middle of the E3-provided range at -0.0015 percent.

Originally, we ordered that Staff work with utilities to facilitate the use of E3's model as a proxy for each of the utilities. Each utility developed a unique approach to calculating

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[25] Order No. 17-357 at 11.
[26] *Id.*
[27] *Id.*
[28] Staff/100, Andrus/38.
[29] *Id.* at 40.

this value, with widely varying results for an element that should have some reasonable relationship to regional market conditions.

In our order establishing the methodology, we indicated a preference for E3's less granular proxy method. This approach will take into account the unique short/long positions of Idaho Power. We may revisit this approach in the future, as with others, where confronted with clear data that indicates an alternative value is appropriate.

H. Hedge Value

1. Methodology Review

For this element, we adopted the E3 suggestion for a 5 percent hedge value of avoided energy. E3's recommendation is derived from a peer-reviewed paper entitled *How Big Is the Risk Premium in an Electricity Forward Price? Evidence from the Pacific Northwest.*[30] We noted that "[w]e decline the suggestion for a zero value, because similar to Market Price Response, we are persuaded that there is value to this element."[31]

2. Idaho Power Application of the Hedge Value Methodology

Idaho Power used the 5 percent proxy value proposed by E3, though Idaho Power expressed concerns with the value. Idaho Power states that this value is inappropriate because the 5 percent number is not consistent with Idaho Power's individual risk management policies.

3. Party Positions

OSEIA recommends a significantly larger hedge value, developed by consultant Clean Power Research as part of the Maine Public Utilities Commission's Maine Distributed Solar Valuation Study released in 2015. This approach assumes that natural gas prices are the most significant driver of marginal energy costs, and calculates the additional costs to lock-in the fuel costs of a marginal gas-fired generator for a 25-year period, compared to purchasing natural gas on an as needed basis. OSEIA's witness then:

> applied the approach developed in the Maine Solar DG Valuation Study to the Oregon IOUs, using their gas commodity cost forecasts, U.S. Treasuries (at current yields) as the risk-free investments, the IOU's weighted average cost of capital, and a marginal heat rate of 7,500 Btu per kWh. The result is hedge values that range from $18 to $23 per MWH as the 25-year real levelized benefit of hedging fuel price uncertainty.[32]

OSEIA's approach is opposed by Idaho Power, the other utilities, and Staff. According to E3, the value described by OSEIA in its proposed hedge may be real but does not

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[30] Andre DeBenedictis, David Miller, Jack Moore, Arne Olsen, & C.K. Woo, *How Big is the Risk Premium in an Electricity Forward Price?*, 24 the Electricity Journal 72, (April 2011).
[31] Order No. 17-357 at 12.
[32] OSEIA/100, Beach/34.

accrue to the utility system, and instead accrues to the owner of any distributed solar generation:

> The remaining load does not experience a reduction in volatility as a result of the solar installation. Behind-the-meter solar does not function like direct access, in which the load is separated from the remaining bundled customers and served with a third-party resource, i.e., a resource that is outside the utility's portfolio. Since the utility does not own or contract directly with the solar PV resource, the utility therefore will need to continue to hedge any market transactions for the remaining load in the same proportion as if the solar installation had not occurred. As a result, the hedge value accrues to the system owner, and the remaining utility ratepayers do not experience a reduction in bill volatility.[33]

For this reason Staff rejects OSEIA's proposal for distributed energy resources, but concedes it might have some applicability for resources that are in front of the meter: "However, Staff will explore whether it is appropriate to include both the hedge value and avoided hedge value in the RVOS calculation when the solar generation at issue is not behind-the-meter."[34]

4. Resolution

We make no changes to the methodology, and approve Idaho Power's value based on the 5 percent of avoided energy calculation. We consider the hedge value to be logical and real, though extremely difficult to quantify. We agree with Staff that the value should be explored in the future, and that it may be possible to develop a better assessment.

We reject OSEIA's proposal because it provides for an oversized hedge value that may be unreasonable. Additionally, OSEIA's hedge values are so large ($18 to $23 per MWh) that they rival or could even exceed the values of the actual energy being produced by a project. Though we agree with OSEIA that the hedge value is a real attribute, we are not convinced that it rivals the value of energy.

I. Environmental Compliance

1. Methodology Review

In our order setting the RVOS methodology, we requested an environmental compliance value from the utilities as a placeholder only, based on carbon regulation assumptions as outlined through individual IRP filings. The environmental compliance value is intended to equal the avoided cost of complying with existing and anticipated environmental standards.

[33] UM 1716 Staff/401, Olsen/24 (Staff Response to TASC DR No. 20).
[34] Staff Reply Brief at 13 (Aug 9, 2018).

2. Idaho Power Application of the Methodology and Party Positions

Idaho Power used a zero placeholder cost for avoided environmental compliance. Staff recommends that Idaho Power review potential carbon costs. Idaho Power objected to Staff's request to analyze potential carbon costs, because such impacts are speculative. Staff finds Idaho Power's approach unreasonable given the "emerging events regarding carbon regulations in Oregon."[35] OSEIA proposed a uniform calculation associated with the compliance cost for a natural gas fired resource.

3. Resolution

We adopt Idaho Power's value as a proxy, but determine that this value should be developed on a program-by-program basis, similar to the administrative value discussed above. Where an individual program implementation effort includes an exchange of environmental attributes, it may be appropriate to value that attribute as part of a long-term exchange. Accordingly, we approve Idaho Power's proposed value as a proxy, but determine that this value can only be appropriately determined through individual program implementation dockets. For example, as part of our Community Solar program, the implementation effort will determine what environmental attribute will be exchanged as part of individual participation. At the time the environmental attribute exchange is established, it should be priced as part of program implementation efforts and that price incorporated into the RVOS for that program application.

J. RPS Compliance

1. Methodology Review

We directed the utilities to assign a zero value as a placeholder for the value associated with RPS compliance. We noted that the cost of RPS compliance review overlapped with examinations in several other dockets and that a value would be assigned at a later time.

2. Idaho Power Application of the Methodology and Party Positions

Idaho Power argues this value should be zero because Idaho Power can meet its RPS requirements starting in 2025 without any additional investment. Staff recommended valuing the RPS compliance element according to the $/MWh from utilities' reports.

3. Resolution

We adopt Staff's recommendation for this element, which has the advantage of utilizing an existing process, and not reinventing a value in a single proceeding in one application that contrasts with how it is utilized in another. Adopting Staff's proposal will also help make reporting of RPS compliance costs consistent, and eliminate the need for two different approaches to RPS cost evaluation methodology. Importantly, we recognize that, like the administration and environmental compliance values, this value must be

[35] Staff Opening Brief at 22.

applied on a program-by-program basis, and any value expressed absent a specific implementation context can be a proxy only, because of the dynamics of individual programs. However, we note that Idaho Power does not produce RPS compliance reports at this time, and will not do so until the Company begins active compliance with the RPS standard. Accordingly, until such time Idaho Power should use the anticipated costs of future RPS compliance, as discussed in its most recently acknowledged IRP filings, to derive this value.

We note that this value will take two forms, depending on program implementation questions. The first will be a MWh detriment to a utility compliance obligation. Where a program essentially results in a utility load reduction, and a diminished need to take action to comply with the RPS standard, then the value to the utility of that reduced compliance requirement should be calculated. Alternatively, where a program includes an exchange of attributes that allow for RPS compliance, such as where Renewable Energy Credits (RECs) are provided to a utility as part of program implementation, then in that case the value of the REC, consistent with the value to the utility as expressed in the RPS compliance report, should be used to create the RVOS element value.

K. Grid Services

We determined that grid services is an element that would be set at zero initially, but that could be valued after the close of the second RVOS phase. The Oregon Department of Energy (ODOE) has argued that this element could be utilized to take into account technological advances in solar such as smart inverters or storage that provide greater system value.

Idaho Power set this initial value as zero, and no parties have objected. We adopt Idaho Power's value for this approach, and request that electric companies, Staff, and parties continue to review this element and consider changes as the value of new grid service technologies become clearer. We find that our to-be-initiated distribution system planning process may provide clearer information about additional grid services that a variety of technologies implicated in solar developments may provide, and request that this process review these potential services.

L. Utility Scale Proxy

We determine that the submission of a utility scale RVOS as a reference will be valuable for illustrating the avoided costs to a utility in acquiring solar through distributed projects, instead of utility scale developments. We adopt Staff's recommended clarifications regarding the utility scale RVOS reference, and require that:

- The most recently acknowledged IRP or IRP update be the source for cost estimates of the proxy.
- The earliest year of capacity deficiency in the IRP be used as the start year for capacity value.

- The proxy be defined as 50 MW or larger and interconnected at the transmission level of the system.

Table summarizing required actions:

Element	**Action Required**	**Completion Date**
Energy	Update consistent with order, express in 12 x 24 blocks. Allocate value across the blocks using 3 years of uncapped EIM prices.	3/18/2019 for levelized value and 12 x 24 blocks
Generation Capacity	Express in 12 x 24 blocks. Allocate value across blocks and provide analysis supporting value spread or ratio across hours.	3/18/2019 for levelized value and 7/18/2019
T&D Capacity Deferral	Update consistent with order, express in 12 x 24 blocks. Allocate value across blocks and provide analysis supporting value spread or ratio across hours. Develop rudimentary locational value in conjunction with Staff.	3/18/2019 for levelized value, 7/18/2019 for 12 x 24 blocks expression and update, 7/18/2019 for locational value
Line Losses	Express in 12 x 24 blocks.	7/18/2019 for 12 x 24 blocks
Integration	N/A	N/A
Administration	N/A	3/18/2019 for proxy value

Market Price Response	Update consistent with order.	3/18/2019
Hedge Value	N/A	N/A
Environmental Compliance	N/A	N/A
RPS Compliance	Update proxy value as consistent with order.	3/18/2019
Grid Services	N/A	N/A

V. Order

IT IS ORDERED that:

1. Idaho Power Company file in this docket updated RVOS values consistent with this order no later than March 18, 2019 and July 18, 2019 respectively.

2. Idaho Power Company will work with Staff of the Public Utility Commission to develop a proposal for the locational valuation to T&D Capacity deferral value and present initial values and locations to the Commission no later than July 18, 2019.

3. Staff open and provide a proposed scope for a general capacity investigation no later than April 23, 2019.

Made, entered, and effective Jan 22 2019.

Megan W. Decker
Chair

Stephen M. Bloom
Commissioner

Letha Tawney
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.