Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204
PortlandGeneral.com

June 30, 2016

Email / FedEx
puc.filingcenter@state.or.us

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RE: UM 1716 Investigation to Determine Resource Value of Solar

Attention Filing Center:

Enclosed for filing in the above referenced matter please find the following:

Response Testimony of:
- **Stefan Brown, Darren Murtaugh (PGE / 100)**

If you have any questions, please contact Jacob Goodspeed at (503) 464-7806.

Sincerely,

Stefan Brown
Manager, Regulatory Affairs

SB/sp

cc: Um 1716 Service List

UM 1716 / PGE / 100
Brown – Murtaugh

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UM 1716

Testimony

PORTLAND GENERAL ELECTRIC COMPANY

Response Testimony of

Stefan Brown
Darren Murtaugh

June 30, 2016

I. Introduction and Summary

Q. Please state your names and positions with Portland General Electric ("PGE").

A. My name is Stefan Brown. I am a Manager of Regulatory Affairs at Portland General Electric Company (PGE). My qualifications appear in Section V of this testimony.

My name is Darren Murtaugh. I am the Manager of Transmission and Distribution Planning and Project Management. My qualifications appear in Section V of this testimony.

Q. What is the Purpose of your testimony?

A. Our testimony is in response to the testimony of Commission Staff (Ms. Dolezel) and E3 Consulting (Mr. Olson) in UM 1716 – Investigation to Determine the Resource Value of Solar in this Phase 1 investigation to examine elements and methodologies of the resource value of solar. Our testimony will articulate the Company's position on the ten elements proposed by Witness Olson for inclusion in a Value of Solar methodology, as well as offer some clarification regarding the current availability of information.

Q. Please provide background and context for your testimony.

A. This docket was opened in early 2015 following a Commission report to the legislature pursuant to HB 2893 (2013 legislative session). The July 2014 report was on the effectiveness of solar programs in Oregon. Staff and stakeholders spent the better part of 2015 filing comments opining on the elements that should be included in the resource value of solar. In September 2015, Staff recommended that the Commission select which of the 26 elements should be examined in determining the resource value of solar. In addition, Staff recommended the hiring of a consultant to assess and develop methods to quantify the selected elements.

Q. Did the Commission identify the elements to include in the resource value of solar?

A. No. While the Commission declined to identify the elements to be included in its Order (15-296), it did state that the Commission would only consider elements that could impact the cost of service to utility customers. As examples, the Commission stated it would consider the cost of carbon regulation to utilities and it would not consider job impacts of solar development.

Q. Has the Commission specified how the resource value of solar will be used?

A. No. The only specific application for the resource value of solar that has been identified is for community solar and that was specified in the 2016 legislation, SB 1547.

Q. What is meant by the resource value of solar?

A. In its report to the legislature, the Commission stated the resource value of solar refers to the value of the benefits solar generation brings to the utility system and electricity customers in general. It does not include potential social benefits.

Q. Why is the determination of a resource value of solar important?

A. It is important to develop an appropriate method for valuing solar resources, particularly distributed solar resources, to ensure appropriate compensation to the generator for the solar energy contribution to our customers. This should be based on value to PGE's distribution system and resource planning.

Q. How is your testimony organized?

A. Our testimony will articulate the Company's position on the ten elements proposed by Witness Olson for inclusion in a value of solar model, as well as offer some clarification regarding the current availability of information.

Q. Did Commission Staff and Witness Olson follow the Commission direction in identifying elements to be included in the resource value of solar?

A. Yes. Mr. Olson identified ten elements that directly impact the cost of service to utility customers and excluded the elements that do not directly impact utility customers.

Q. Please list the ten elements that Mr. Olson proposes be included in the Resource Value of Solar (RVOS) methodology.

A. As detailed in the chart in Staff/200 Olson/26 at 7, the elements included in the RVOS methodology are as follows (a "+" indicates a benefit as a result of solar, a "-" denotes a cost of solar):

$$
\begin{aligned}
&\forall h \in [1, \ldots, 8760] \\
&Value_h = Energy_h \\
&\qquad + Generation\ Capacity_h \\
&\qquad + Line\ Losses_h \\
&\qquad + T\&D\ Capacity_h \\
&\qquad + RPS\ Compliance_h \\
&\qquad + Market\ Price\ Response_h \\
&\qquad + Hedge_h \\
&\qquad - Integration_h \\
&\qquad + Environmental\ Compliance_h \\
&\qquad - Administration_h
\end{aligned}
$$

Q. Does PGE agree with the ten elements selected by Mr. Olson to be included in the RVOS methodology?

A. Yes, we find the elements proposed by Mr. Olson to be reasonable. Further, we feel that the 10 elements can accurately reflect the costs and benefits that would directly impact the cost of service to utility customers (as defined in Order 15-296 at 2).

However, while we find the elements included in the RVOS methodology by Witness Olson to be reasonable from a high-level perspective, we do have concerns regarding the availability of inputs necessary to calculate the value of the elements. Mr. Olson's methodology leans heavily on the use of time and location specific data to calculate the RVOS. PGE does not have inputs for certain elements at that level of granularity. We discuss these concerns in more detail in Sections II, III, and IV of this testimony. Moreover, it is not clear how the methodology proposed by Mr. Olson will be implemented. In other words, while we agree in principle with the approach recommended by Mr. Olson, the devil is in the details and there are many details that we do not currently have.

Q. Given PGE's high level support for the elements identified, do you have any concerns regarding specific values to calculate the elements?

A. Yes. A key concern regards the availability of detailed values to calculate the elements. Mr. Olson's methodology leans heavily on the use of time and location specific data to calculate the RVOS; we do not have inputs for certain elements at that level of granularity. We discuss these concerns in more detail in Sections II, III, and IV of this testimony.

Q. Please summarize your clarifications as they pertain to the ten elements recommended by Mr. Olson for inclusion in the Value of Solar methodology.

A. The following chart provides a summary of our clarifications.

RVOS Element	Staff Definition	PGE Clarification (if applicable)
Energy	Marginal avoided cost of purchasing or selling electricity into the wholesale market, OR, hourly marginal cost of energy from conventional wholesale generating resources including the cost of fuel (and associated fuel transportation costs), variable operations and maintenance, labor, and all other variable costs.	PGE does not calculate avoided marginal cost of energy at an hourly level. We propose to use Schedule 201 avoided costs to obtain this value. (We address this element in section II of this testimony).
Generation Capacity	Marginal avoided cost of building and maintaining the lowest net cost generation capacity resource.	PGE proposes to use Schedule 201 avoided costs to obtain this value (we address this element in section II of this testimony).
Line Losses	Avoided marginal electricity losses from the point of generation to the point of delivery.	

Transmission and Distribution (T&D) Capacity	Avoided or deferred costs of expanding, replacing, or upgrading transmission and distribution infrastructure such as substations, lines, and transformers.	We are not currently able to provide potential avoided T&D calculations. Also, we want to maintain a bright-line demarcation between infrastructure upgrades due to load growth and upgrades due to reliability and replacing aging infrastructure (we address this element in section III of testimony).
Renewable Portfolio Standard Compliance	Avoided incremental cost of purchasing renewable energy to satisfy the Oregon RPS requirement. The incremental cost is defined as the levelized cost of a renewable resource less the value of that resource provides from energy, capacity, and environmental compliance plus the cost of that resource due to renewable integration.	This element would apply only if the RPS compliance is truly avoided and PGE gets the RECs from the solar production.
Market Price Response	The change in utility costs due to lower wholesale energy market prices caused by increased solar PV production, affecting the price at which the utility transacts in the wholesale market when managing its portfolio of resources on behalf of its retail customers. Lower market prices result in lower costs for utility market purchases, but reduced margins for utility market sales. The net effect on the utility could be either positive or negative, depending on the relative magnitude and timing of market purchases and sales. Lower market prices are not a societal benefit, because they represent a transfer of wealth from one member of society (electricity producers) to another member (electricity consumers).	We agree with this element from a high-level perspective. However, PGE does not currently calculate this data and a usable proxy has not been suggested. We are open to working with Staff and stakeholders to determine the form of this calculation and the appropriate values associated with it.
Hedging	Avoided cost of utility fuel cost hedging activities (i.e. transactions intended solely to provide a more stable retail rate over time).	PGE does not currently calculate this value. Further, we note that this could be a cost to solar if PGE plans for a reduced long-term hedge and the solar resource is not available or solar penetration does not materialize to the level PGE expects. We address this element further in Section IV.
Integration	Increased costs associated with integrating solar PV into the electrical system. These costs include additional spinning reserve and ancillary service requirements	

	necessary to facilitate the variability and intermittency of solar PV production, as well as any change in ancillary service procurement due to reduction in metered load.	
Environmental Compliance	Avoided cost of complying with existing and anticipated carbon standards due to a reduction in carbon emissions from the marginal generating unit. The cost of compliance with criteria pollution regulations is assumed to be captured in the avoided cost of generation capacity.	
Administration	Increased costs to administer distributed solar PV programs such as net energy metering (NEM). This includes the cost of additional utility staff, incremental billing software, incremental costs of interconnection and any other utility-specific costs. Incremental costs of interconnection are defined as the total cost of interconnection less the portion of the cost paid by the interconnecting solar generator.	

Q. Does PGE propose any additional elements for inclusion in a value of solar calculation that were not included in E3's opening testimony?

A. No. The Company does not propose any additional elements at this time; the elements proposed by E3 are appropriate in calculating the value of solar elements that impact utility customers.

Q. Does PGE propose any elements be removed from Mr. Olson's methodology?

A. No, however, as noted above, we do not view the use of the RVOS methodology as a binary "all or nothing" approach, but rather a system to ensure the accurate calculation of benefits and costs *when they exist.* For example, there may be a situation where, due to the unique nature of the project, there is no realized benefit for Transmission and Distribution Capacity.

In this situation we would advocate including all applicable elements while disregarding (or setting to zero) those that do not apply.

II. Energy and Capacity

Q. Does PGE agree with the methodology for valuing generation capacity that E3 set forth in their testimony?

A. Yes, PGE generally agrees with the methodology of valuing avoided capacity during a deficiency period as Mr. Olson described: through the carrying cost ($/MW-yr) – the levelized fixed cost of the resource (likely a simple cycle combustion turbine (SCCT)) minus expected revenues that could be earned through market dispatch[1]. However, we propose that Schedule 201 Avoided Costs to be the most appropriate source for these calculations. Avoided cost is already an established process (which is tied to the IRP) with a predictable update schedule. The values derived from Schedule 201 would then be inputs into the RVOS to support PGE's calculations of avoided capacity and avoided energy.

Q. On page 30 of his testimony, Mr. Olson mentions that utilities in Oregon have worked to develop a methodology to capture solar's contribution to peak through Docket UM 1719. Does PGE advocate for adopting this approach?

A. Not necessarily. PGE advocates tying the RVOS calculation of the energy and capacity inputs to the methodology approved in conjunction with the Company's most recently acknowledged IRP (or through another Commission-acknowledged process such as the IRP Update or similar mid-cycle filing). As noted by Mr. Olson, utilities have been working to develop an updated methodology for avoided renewable capacity investments. However, this is not the methodology that was used in the PGE's 2013 IRP. To maintain transparency, consistency, and fairness, we recommend tying the calculation of avoided capacity to what was used in the IRP (or other Commission-acknowledged) process, not one specific

[1] Staff/200 Olson/30 Table 3

methodology. We note that the methodology described by Mr. Olson is being used in PGE's 2016 IRP and will likely be included in Schedule 201 after acknowledgement.

Q. How would linking the calculation of avoided capacity to a Commission-acknowledged filing (such as the IRP, IRP update, or Renewable Portfolio Implementation Plan (RPIP)) benefit stakeholders in this process?

A. The benefit of using the avoided capacity methodology associated with the most recently acknowledged IRP (or IRP update or RPIP), is that it allows stakeholders to be nimble with the RVOS calculations (just as they are with the IRP, IRP Update, or RPIP) while maintaining the rigor that the IRP process provides. Further, as the technology of solar production evolves and solar penetration in the market increases, the calculation of this element would be able to be modified (if needed) in a transparent and consistent manner through the IRP process.

III. Transmission and Distribution

Q. Does PGE agree with Mr. Olson that avoided transmission and distribution investment as a result of load growth is a benefit of solar?

A. Yes. The Company agrees that avoiding infrastructure investments or deferring infrastructure investments that would normally be necessitated by load growth related constraints on PGE's system is of value to utility customers.

Q. Is PGE currently prepared to forecast the value of avoided T&D that would be provided by distributed energy resources (DER)?

A. No. As noted in Mr. Olson's testimony, the value associated with avoided transmission and distribution investment associated with load growth would be highly location-specific and could vary greatly depending on the location of the solar project on PGE's distribution system (if the solar project is on PGE's distribution system at all). Further, PGE wishes to ensure that we do not conflate infrastructure upgrades due to capacity need with upgrades that are due to reliability or replacing aging infrastructure. Only deferred capacity investment resulting from solar should be included in this element, as system reliability investments related to aging infrastructure would be made regardless of solar contribution. In order to qualify as a capacity-related deferral, the solar resource should be able to reliably deliver output through the duration of a peak event.

Q. In advance of E3's testimony and accompanying Exhibit 201 (RVOS model), utilities were asked to submit values to help inform the development of the model. Was PGE able to provide T&D avoided cost estimates?

A. No. During the development of E3's model, PGE was unable to provide avoided cost estimates for transmission and distribution. Instead, the Company used Loss of Load

Probability (LOLP) as a proxy value. However, LOLP is not the correct data to accurately value this benefit. Although not currently available, hourly usage data by feeder is the correct data to measure peak usage and accurately estimate avoided T&D benefit.

Q. In the absence of readily available avoided transmission and distribution data, what does the Company propose?

A. Due to the locational variability of the infrastructure deferral benefit, PGE recommends using the net present value (NPV) of the revenue requirement of the deferred capacity investment over the period of the deferral. This would be only for solar systems that are capable of reliably delivering output during a system peak event, as mentioned above, and are large enough, in aggregate, to defer the needed capacity.

IV. Methodology and Uses

Q. Beginning on page 35 (line 15), Mr. Olson asserts that the RVOS methodology is appropriate for distributed solar, but is not an appropriate calculation for utility-scale solar. Does PGE agree with this assessment?

A. No. As referenced earlier, recently passed legislation amending the Renewable Portfolio Standard, Senate Bill 1547 (Section 22.1.6.A regarding community solar), contains a community solar provision that directs the use of RVOS to value the solar production. It states that the amount of electricity generated by a community solar project shall be valued in a manner that reflects the resource value of solar energy. While E3's testimony is correct that many utility-scale solar projects will use both the transmission and distribution systems (thereby missing out on the line loss as well as T&D avoided investment benefits), we respond that in this rapidly evolving area, that may not always be the case. Thus, we advocate for the ability to use the RVOS established in this docket to analyze utility-scale projects on a case by case basis – retaining the RVOS elements that are applicable to a specific utility project, and dropping elements that do not apply.

Q. SB 1547 also gives the Commission the authority to assess a different rate to solar if the Commission "has good cause." Wouldn't the fact that utility-scale solar generally uses both the transmission and distribution system be a "good cause" to not apply the RVOS?

A. Perhaps. As mentioned, the calculation of the RVOS may need to be adjusted to account for the specifics of each project. As stated above, PGE advocates that in the case of utility-owned projects, application of each element of the RVOS should be taken into account based on the specific characteristics of the solar project. A utility project could be analyzed at the feeder level to assess the value of elements such as line loss avoidance and the ability to avoid transmission and distribution capacity upgrades. In a situation where some elements of the RVOS methodology do not apply, but other elements do, the utility should be able to work with the Commission and other stakeholders to determine how to value the resource. PGE does not view this methodology as binary, but rather a set of guidelines on how to calculate benefits and costs if they exist.

Q. In advance of E3's testimony and accompanying Exhibit 201 (RVOS model), utilities were asked to submit values to help inform the development of the model. Was PGE able to provide a methodology for estimating the benefit of solar resources reducing the Company's need to hedge fuel purchases?

A. No. While we do not necessarily disagree with E3 and Staff in their assertion that solar resources should be able to reduce a utility's need to hedge to reduce fuel risk, the hourly avoided hedging benefit of solar is not something that PGE currently calculates. Further, if the utility modifies hedging strategies to factor in the assumed benefit of available solar resources, and those resources do not produce when needed or do not gain the market penetration that the utility plans for when adjusting the hedge, the reduced hedge *could* be a cost to customers.

Q. Does PGE currently have a methodology in place to accurately measure the impact of solar on the hedging strategies of the Company?

A. No. But the Company is open to working with Staff and stakeholders to develop a methodology or proxy value for this element.

V. Qualifications

Q. Mr. Brown, please state your educational background and experience

A. I have more than twenty years of experience in the energy industry. I have been a Manager in Rates in Regulatory Affairs with PGE since 2016. Previously, I was a Resource Strategy Project Manager with PGE from 2012 to 2016. I started working for PGE in 2007 as a BPA Policy Analyst. Prior to working for PGE I held a Senior Economist position with the Oregon Public Utility Commission. I have also held other Economist positions prior to working at PGE.

I received Bachelor of Science degrees in Agricultural and Resource Economics and Animal Science from Oregon State University in June 1983. I received a Master of Science degree from the University of Wyoming in Economics in May 1991. I received a Doctorate of Philosophy from Purdue University in Agricultural Economics in August 1995, where natural resource economics and production economics were my major fields of study.

Q. Mr. Murtaugh, please state your educational background and experience.

A. I received a Bachelor of Science degree from the University of Nevada in Electrical Engineering in December 2002. I have also received advanced training and coursework from a variety of schools and companies. I obtained my Professional Engineer license in the State of Oregon in December 2007.

In 2012, I accepted my current position as a Manager of Transmission and Distribution Planning and Project Management at PGE. Previously I worked as a Lead Planning Engineer with PGE. Prior to working for PGE, I worked in Transmission Operations with Sierra Pacific Power Company in Reno, Nevada.

Q. Does this conclude your testimony?

A. Yes.