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May 5, 2017

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Filing Center
Public Utility Commission of Oregon
201 High Street, SE Ste. 100
PO Box 1088
Salem, OR 97301

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:
Testimony of:

- **Darren Murtaugh – Jacob Goodspeed (PGE /300-301)**

If you have any questions, please contact me at (503) 464-8718 or Jacob Goodspeed at (503) 464-7806.

Sincerely,

Karla Wenzel

Karla Wenzel
Manager, Pricing & Tariffs

KW/sp

cc: UM 1716

UM 1716 / PGE / 300
Murtaugh - Goodspeed

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UM 1716

Investigation into Resource Value of Solar

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Darren Murtaugh
Jacob Goodspeed

May 5, 2017

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I. Introduction and Summary

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

A. My name is Darren Murtaugh. I am the Manager of Transmission and Distribution Planning and Project Management at Portland General Electric (PGE). My qualifications appear in Section V. of this testimony.

My name is Jacob Goodspeed. I am an Analyst in Pricing and Tariffs for PGE. My qualifications appear in Section V. of this testimony.

Q. What is the Purpose of your testimony?

A. The purpose of our testimony is to respond to the request for additional process in UM 1716 – Investigation into the Resource Value of Solar (RVOS) – as outlined in Order 17-085. This testimony will :

- Provide written responses to the questions asked by the Oregon Public Utilities Commission (OPUC or Commission) during the hearing on January 31, 2017.
- Respond the the Straw Proposal that was distributed by the Commission – which lists the methodologies that are viewed to have consensus support – and to suggest potential path to resolution for those elements which do not yet have consensus support.
- Discuss how Phase II of this docket should proceed, including identifying any preferences for how utilities should calculate RVOS values in Phase II.

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.

Staff has conducted a robust public stakeholder process to determine how to accurately value the RVOS, and in accordance with Order 15-296, proposed a set of 10 elements that directly impacted the cost of service to utility customers. Following Staff's identification of 10 elements, stakeholders have had two rounds of written testimony, two rounds of briefs, and been examined by the Commission. This written testimony will address the final questions of Phase I and will outline PGE's proposal for the structure of Phase II.

Q. Did the Commission identify the elements to include in the resource value of solar in advance of the testimony of Staff witnesses Olson and Dolezel in June 2016?

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. PGE believes that the methodology proposed by Staff witness Olson satisfies this criteria.

Q. Has there been any specific indication of how the Resource Value of Solar will ultimately be used?

A. Yes. A specific application for the resource value of solar has been identified for community solar and was specified in the 2016 legislation, SB 1547. Additionally, in the UM 1758 Solar Incentives Report from the Commission to the Oregon Legislature, resource value of solar "should also be used for net metering… We will open a docket on examining the integration of the resource value of solar for net metering."[1]

[1] UM 1758 Solar Incentive Report to Legislature, page 3, sent November 1, 2016

II. Response to January 31, 2017 Hearing

Q. Does PGE wish to submit written responses to the questions raised at the Commission hearing held January 31, 2017?

A. Yes. PGE's responses to Commissioner questions are attached as Exhibit 301.

Q. Does PGE amend or otherwise clarify its responses that were given verbally during the hearing on January 31?

A. No. The responses included as Exhibit 301 are the same as those given verbally during the direct examination with Commissioners, and the submittal of responses in written form are intended to provide clarification only.

III. PGE Response to Commission Straw Proposal

Q. Does PGE agree with the Commission's assessment that there is general consensus on numerous issues related to the establishment of elements that will compose the resource value of solar?

A. Yes. Broadly speaking, there has been agreement from parties in this proceeding that the 10 elements selected for inclusion by Staff witness Olson are reasonable. PGE has expressed that we find the elements reasonable in PGE/100 Brown – Murtaugh, PGE/200 Brown – Murtaugh, and in legal briefs filed August 26 and September 19, 2017.

The Citizens Utility Board, Oregon Department of Energy, and joint parties requested in testimony that "Security: reliability, resiliency, and disaster recovery" be added as an element, which the OPUC elected to do on a future looking basis, acknowledging that the current value is likely zero without the presence of microgrids or widespread use of smart inverters. PGE also finds the treatment of this element to be acceptable.

Q. Does PGE find the Commission straw proposal included in Order 17-085 to be reasonable?

A. Yes. PGE largely supports the definitions, methodologies, and next steps listed in the Commisison straw proposal (shown in Figure 1 below). Our proposed comments to the straw proposal are discussed throughout the remainder of this section.

Figure 1 – Commission Straw Proposal

RVOS Element	Definition	Methodology	Next Steps
Energy	The marginal avoided cost of procuring or producing energy, including fuel, O&M, pipeline costs, and all other variable costs	Utilities shall estimate the marginal avoided cost of energy using the methods currently used for their QF avoided costs (monthly values with on- and off-peak blocks). Utilities shall model a range of hydro conditions to forecast energy prices. Utilities must examine and evaluate different schemes for weighting hydro years and report the results of their examination.	The utilities shall propose this value in Phase II. At a later date, Staff shall convene a workshop/technical conference to examine the need for and costs of modeling refinements to estimate the marginal avoided cost of energy at a smaller time interval.
Generation Capacity	The marginal avoided cost of building and maintaining the lowest net cost generation capacity resource.	Utilities shall use their IRP resource sufficiency/deficiency demarcation and shall determine the capacity value consistent with the Commission's standard QF avoided cost guidelines. Utilities shall use their IRP's value for solar's contribution to capacity or peak. (For reference, when the utility is resource sufficient, the QF receives standard prices based on the market energy price (see Order No. 16-174). When the utility is resource deficient, the QF receives standard prices based on the capacity and energy costs of a proxy resource, scaled for solar's contribution to peak (see Order No. 16-174 and Order No. 16-337.	The utilities shall produce this value in Phase II. During Phase II, the utilities shall run sensitivity analyses to determine when the level of solar PV penetration has a material effect on the timing of the need for new resources (the deficiency demarcation).
Transmission and Distribution (T&D) Capacity	Avoided or deferred costs of expanding, replacing, or upgrading transmission and distribution infrastructure.	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. The avoided or deferred costs shall be for growth-related investments.	The utilities shall propose this value in Phase II. At a later date, Staff shall convene a workshop/technical conference to examine ways to generation location-specific T&D capacity deferral estimates (and the information needed to make such estimates) and to assess the costs imposed on distribution system by

			increasing penetration of solar PVs.
Line Losses	Avoided marginal electricity losses from the point of generation to the point of delivery.	Utilities shall develop estimates 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.	The utilities shall propose this value in Phase II.
Administration	Increased utility costs of administering solar PV programs.	Utilities shall develop estimates of the direct, incremental costs of administering solar PV programs including staff, software, interconnection, and other utility costs.	The utilities shall propose this value in Phase II. Utilities shall provide justification for their method and value.
Market Price Response	The change in utility costs due to lower wholesale energy market prices caused by increased solar PV production.	To be evaluated with follow-up.	In tandem with Phase II, Staff shall convene a workshop/technical conference to examine an empirically-sound way to estimate the impact of incremental solar generation in Oregon service areas on wholesale market prices. Using an acceptable method, utilities shall develop preliminary estimates of the impacts of incremental solar generation on both wholesale purchases and sales. Utilities shall report their preliminary results in Phase II.
RPS Compliance	Avoided net incremental cost of purchasing renewable energy credits (RECs) to satisfy the renewable portfolio standard (RPS).	The levelized cost of the marginal renewable resource installed in the year when utilities need to act to comply with RPS requirements less energy, capacity, and environmental compliance values, plus any integration cost. Utilities shall estimate an avoided value based on reduction in load attributable to incremental solar generation in Oregon service areas.	The utilities shall propose this value in Phase II.
Integration and Ancillary Services	Change in a utility's need for ancillary services due to changes in metered load and net load variability. Includes contingency reserves (spin and non-spin) needed for sudden	Utilities will make estimates of integration costs based on acknowledged wind and solar integration studies. Utilities will assign a value of zero to ancillary services benefits of increased penetration of solar	The utilities shall propose this value in Phase II. At a later date, Staff shall convene a workshop/technical conference to evaluate the

	outages; load-following reserves for fluctuations over the 5 to 60 minute time scale, and regulation reserves to accommodate sub-5 minute fluctuations.	PVs.	incremental system benefits from enabled advanced inverters and ways to evaluate those benefits.
Hedge Value	Avoided cost of utility hedging activities, i.e., transactions intended solely to provide a more stable retail rate over time.	To be evaluated with follow-up.	Staff shall conduct a workshop to examine methodologies to quantify hedge value. Based on the methodology recommended by Staff, the utilities shall produce a preliminary value in Phase II. Parties are to examine the preliminary value and consider the interafction of utility hedging strategies and increased solar penetration as well as value placed by customers on marginal electricity price stability. The preliminary value and examination will inform the justification for an acceptable method and value used by each utility.
Environmental Compliance	Avoided cost of complying with existing and anticipated environmental standards.	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 assumptions from their IRP.	The utilities shall propose a value in Phase II and explain how the value is consistent with IRP assumptions.
Security, reliability, and reserves	The potential capability of solar, when deployed in combination with other technologies such as energy storage and control systems, to provide backup energy or microgrid islanding capabilities during a loss of service from the utility.	The utility shall include an element for security, reliability, and reserves but assign a value of zero currently.	Staff shall conduct a subsequent workshop/technical conference to examine methodologies to quantify the value of benefits and the circumstances under which they are applicable, only considering the value provided to the utility system and value that is not already captured in energy, capacity, and ancillary services.

Q. Does PGE have any concerns regarding the suggestion to have utilities model a range of hydro conditions and "examine and evaluate different schemes for weighting hydro years and report the results of their examination?"

A. Yes. PGE notes that there is already an established process for modeling and weighting hydro conditions that currently exists as part of the Company's integrated resource planning (IRP) process. This standard process is used to evaluate potential utility need for new resources, and PGE advocates that the weights and methods used in the IRP context be used to establish the resource value of solar as well. Having an identical process helps - maintain continuity in the planning and forecasting process, as well as easing administrative burden on all parties. Without waiving this concern, if the Commission wishes to model the marginal cost of energy over a shorter time period, PGE is not opposed to the technical conference/workshop construct suggested in the straw proposal.

Additionally, if the Commission wishes to shorten the time period for calculating the marginal cost of energy, PGE would prefer to have a more robust calculation that models a range of hydro, gas, future carbon, and other variable renewable output with a reasonable bound on potential outcomes.

Q. PGE testified on January 31 that the Company views the elements "Market Price Response" and "Avoided Hedge Value" to currently have a de minimis value, although the Company acknowledged that these elements may see their value grow over time if solar penetration significantly increases. Does PGE have any comment on the proposed treatment of these elements in the Commission's straw proposal?

A. Yes. PGE reiterates that while the value of these elements has the potential to grow in the future, we view these elements as currently unable to add material value to the resource value of solar price at the current level of solar penetration in Oregon. PGE finds the technical conference/workshop structure proposed by the Commission to be reasonable, and it will likely foster collaboration between the intervening parties in valuing this element. However, we continue to caution that it may not be possible to have a non-zero current value for this element, even if attempts are made to quantify and value it correctly.

IV. Suggestions Regarding Phase II of this Docket

Q. Does PGE have any concerns regarding using the "next steps" portion of the Commission straw proposal to inform the structure of Phase II of this docket, and to provide guidance on how utilities should value certain elements?

A. No. PGE appreciates the Commission-suggested approach of allowing utilities to propose a value when the element is similar to a calculation that already exists within the regulatory framework. We are also amenable to the OPUC's proposed decision to hold workshops and/or technical conferences for elements that are not currently calculated in Oregon or for those that have questions around calculation methodology.

Q. Please describe PGE's preferred structure for the second phase of this docket.

A. PGE strongly prefers to propose values for each element through a compliance filing process, similar to what has been used for implementation of PURPA in UM 1610 and other dockets, which would provide the foundation of an RVOS that could be used to compensate solar in Oregon.

We strongly believe that the overall consensus regarding the majority of these elements – paired with the "next steps" guidance provided in Order 17-085, and a final order provided upon completion of Phase I of this docket – will allow a Phase II that sees utilities offering a proposal for all elements except for those labeled "to be evaluated with follow-up" in Order 17-085. If intervenors largely find PGE's calculations of these elements to be reasonable, there should be no additional process except for the technical conferences identified by the Commission. If intervenors have concerns with PGE's method of calculating these elements, they will have the opportunity to raise these points through written testimony.

Q. How would PGE's proposed structure for Phase II account for elements that are labeled "to be evaluated with follow-up" by Order 17-085?

A. In PGE's planned initial compliance filing to begin Phase II, the bill credit values for Market Price Response and Hedge Value would be set to zero until the additional process to value these elements is complete. As PGE does not currently calculate solar's impact on the wholesale market or how a marginal solar resource may impact our mid-term hedging strategy, any value in Phase II would need to be informed by stakeholder discussion and Commission direction.

Q. Order 17-085 identifies three elements (Energy, Transmission and Distribution Capacity, Integration and Ancillary Services) as those that should have a utility value proposed in Phase II, but should also have additional process in the form of workshops and/or technical conferences. How does PGE propose to treat these elements?

A. PGE – following the guidance included in the straw proposal and any additional guidance in the final order in this phase – will propose values for these elements based on the current uses in other well established contexts where these calculations are utilized (as applicable). Thus, the marginal cost of avoided energy will match closely to what is currently provided in PGE's Schedule 201 avoided cost calculations; Integration and Ancillary Services will be derived from existing integration studies. For Transmission and Distribution Capacity upgrades, PGE will propose a system-average value of avoiding capacity-driven upgrades, knowing that the value may be refined or changed through the technical conference/workshop process.

V. Qualifications

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. Mr. Goodspeed, please state your educational background and experience.

A. I received a Bachelor of Arts degree in Public Policy from Washington State University and a Master of Business Administration degree from the University of New Orleans. I accepted my current role at PGE in 2016, and have previously worked in Senior Pricing Analyst and Pricing Lead roles for Entergy Services, Inc., providing pricing and rate design support to Entergy Louisiana LLC., Entergy Texas Inc., Entergy New Orleans Inc., and Entergy Arkansas Inc. I have also served as a financial analyst in Entergy's nuclear organization.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
301	PGE's responses to Commissioner questions

UM 1716 – Investigation to the Resource Value of Solar

Date of Commission Examination: January 31, 2017; 930-1130am

Witnesses: Jacob Goodspeed and Darren Murtaugh

PGE responses to questions issued by the PUC to all witnesses.

1. **Should the Commission require all utilities to provide the forecasted value of avoided energy costs on an hourly basis? What is the gain in precision by doing so? What is the cost of doing so?**

   PGE does not currently forecast avoided energy costs on an hourly basis, although this could theoretically be done. While there may be a gain in precision by moving to hourly values in the prompt years (perhaps to approximately 2 years out), that precision would disappear as we move further out in time due to market illiquidity and market events that cannot be forecasted. Forecasting avoided energy on a monthly basis allows some "smoothing" of these events that are difficult to forecast and provides an aggregate view of an illiquid market, thus helping us avoid false precision in forecasting. PGE's view is that any value gained through hourly forecasting is traded off by increased administrative burdens on both the Company and on OPUC Staff.

2. **Utilities model a range of hydro conditions to generate an estimate of the avoided cost of energy. Is that sufficient? If not, why not and what modelling should the utilities be doing and how should the results for different hydro conditions be presented?**

   Yes it is sufficient. Modelling a range of hydro conditions to estimate the avoided cost of energy is preferable because it keeps the avoided cost estimate, for purposes of RVOS calculation, in line with the long-term system planning modelling that PGE conducts. If the Commission or other stakeholders want a modified process, we would prefer a more robust calculation that closely mirrors the IRP process (modeling of a range of hydro, gas, future carbon, and variable renewable output with a reasonable bound on potential outcomes).

   We strongly disagree with any suggestions to model *less* than a range of hydro conditions, including any suggestion to model "catastrophic" or 20-year-low hydro years only.

3. **Should the Commission require the utilities to use a resource sufficiency/deficiency demarcation as is now used to generate QF avoided costs? If so, should the Commission require the utilities to revisit the demarcation timing assuming that forward-looking incremental solar PV generation additions are not included as a reduction in the load used to determine the demarcation?**

Yes, in response testimony filed June 30, 2016, PGE advocated for the ability to use avoided energy and capacity calculations directly from the filed QF avoided cost as part of the calculation of the RVOS price. Further, we view incremental solar facilities as helping the utility to defer the acquisition of further RPS compliant resources – whether through RECs or through reduction in total sales. In light of this, we suggest the ability to have the same sufficiency/deficiency demarcation as the QF avoided cost price, as informed by our IRP and our RPS compliance updates. This would reduce the confusion of having a sufficient/deficient avoided cost inform an RVOS that does not have a sufficiency/deficiency mechanism and will establish continuity between the RVOS, the QF price, and our long-term system planning process.

4. Should the Commission require the utilities to value avoided energy costs during a resource sufficiency period as currently set forth in the Commission's QF avoided cost rules? If not, what changes should be made and why?

Yes. In response testimony filed June 30, 2016, PGE advocated for the ability to use avoided energy and capacity calculations directly from the filed QF avoided cost as part of the calculation of the RVOS price. Our view on this has not changed, and we encourage the Commission to align the QF avoided cost and RVOS prices as much as possible. If a utility is "sufficient" from an IRP/QF viewpoint, we do not see a reason to have the utility not be sufficient from an RVOS perspective. In general, we would prefer continuity between a utility's long-term planning process, QF avoided cost pricing process, and RVOS pricing process.

5. Should utilities estimate the value of solar to defer or eliminate the need for T&D upgrades solely when an upgrade is required to meet load growth?

At this time we view peak load growth as the sole driver behind distributed solar-based avoided T&D capacity upgrades. Depending on level of penetration of smart inverters, this may be re-examined in the future.

6. Some argue that increased solar generation could increase distribution system O&M expenditures. What empirical evidence exists or could be generated to support that assertion?

High penetrations of distributed solar may impact both O&M and Capital expenditures on the distribution system. PGE has already modified the standard substation design to include additional monitoring equipment at the substation in anticipation that interest in distributed energy resources will continue to grow. To maintain a safe and reliable system, there will continue to be changes to protection design, including new relays and replacement of substation fused devices with circuit breakers. Voltage management will become more complicated, and utilities may need to consider new devices to regulate feeder voltage on a more granular level.

From an O&M standpoint, increased variability in distributed load and generation may result in more operations for voltage-regulating equipment, leading to increased wear and tear on the system. Utilities will need increased visibility into the system to more actively manage system voltage and feeder imbalance, which may require a Distribution Management System (DMS) and Distribution Operations Center personnel to interface with the system. On a more regional level, utilities will need to consider the ability to satisfy system needs for frequency response and operating reserves for high penetrations of solar.

7. **The transmission and distribution capacity value is highly location-dependent. Given available data, should the Commission consider using a system-wide average as a proxy and why or why not? Given available data, are there ways to differentiate value by geographic area that would provide more accurate estimates by area? (by "geographic area" we are not necessarily assuming down to the individual feeder level but rather if there is a geographical area designation between the entire system (and use of a system-wide average) and feeder level that could be used to derive area-specific values.)**

   We favor the system-wide average approach. PGE has a relatively compact distribution service territory, and the system configuration routinely changes to support operations. With limited geographic variability across the service territory, the system-wide average would be more manageable approach.

8. **What additional data would need to be collected to derive a more accurate T&D capacity value by area? What additional work or investment would be required to collect additional data to calculate location-specific values?**

   To be effective in deferring T&D capacity additions, the value would need to consider the quantity of solar generation which is available during the times of the system peak load, especially during the summer and winter seasons. To fully derive location-specific capacity values, utilities would need to undertake a feeder-level study of system constraint. A uniform methodology would need to be developed to set the study assumptions, including longer-term location-specific load projections and location-specific DER penetration, so potential constraints may be more accurately identified.

9. **With small variations in approach, there seems to be general agreement on the valuation of administrative costs and line losses. Should the method for calculating incremental administrative costs and line losses be left to utilities as long as each utility provides sufficient justification for the method used and value derived?**

   Yes. As stated in testimony by E3 Witness Olson, the administrative cost element largely comprises the utility's cost of customer interconnection and the ongoing customer-related costs such as billing, software, additional utility staff to accommodate solar customers, etc. The marginal cost of customer additions are currently calculated regularly by utilities through a rate case process and those calculations are used to set retail rates. Utility familiarity with this process (and Staff/intervenor familiarity with looking at customer cost calculations) indicates that the combination of a utility cost study and the corresponding justification of method used and value derived should be sufficient to determine this element.

Line losses are generally the same: utilities have a process of calculating this in place currently, and the results are largely accepted (subject to OPUC approval) for the purposes of setting rates. We do not see a reason to treat the calculation process for either line losses or customer costs any differently in the case of RVOS-specific pricing.

10. **Should utilities estimate both the impact of lower wholesale prices on customer costs and lower surplus sales revenue?**

PGE is not opposed to creating a calculation mechanism (or proxy method) for this element, and having it available for use in the future. However, the current amount of solar penetration in Oregon is not sufficient to impact wholesale pricing (on either the buy or sell side) for the utility. If the penetration of solar significantly increases in the future to the point where wholesale price impacts are seen (similar to SP-15 currently), the mechanism will capture this benefit and reflect the value-stream accordingly. Wholesale transactions will net out through purchase and sales.

11. **There appears to be no ready empirical research or quantitative formula for determining a reasonably accurate measure of the impact of increased solar generation in Oregon on regional wholesale power sale prices. Should the Commission require the use of a proxy method? If yes, what should be the basis of that method and what evidence exists to back up a proxy method?**

Requiring the use of a proxy method would allow RVOS stakeholders to have a more immediate answer, but a proxy ultimately leads to a less accurate or less applicable RVOS price. PGE does not view solar impact on wholesale to be a value stream currently, but rather one that may grow over time. We request that the Commission – rather than requiring an immediate proxy calculation based off of incomplete or non-Oregon data – direct stakeholders to explore how to create an accurate value for Oregon's solar impact on the wholesale market so that this value may be captured when it emerges.

12. **What research and modelling work, if any, should the Commission require and by whom to generate a workable calculation formula (related to impacts of increased distributed solar on wholesale power sales prices)?**

If the goal is estimation via proxy value, PGE is currently able to run this through our AURORA system. However, the results of this analysis would be directional only and should only be used to inform general trends. Time-based accuracy could be improved in a proxy scenario by shortening the window of time being analyzed.

If a more exact, Oregon-specific value is needed, the Commission should focus on a production-cost based model that is able to model more specifically the unique situation in WECC and how projected growth (based off of potential studies and solar availability) could impact the wholesale market. We're neutral as to who does the work, but...

13. In general, the utilities disagree with the proposed hedge value calculation formula and argue that hedge value should be set to 0 based on their hedging policies and other factors. Do other parties agree or disagree with these assertions and why?

[N/A, geared toward non-utility parties]

14. What research and modelling work, if any, should the Commission require and by whom to generate a workable calculation formula (with regard to fuel hedge value)?

PGE believes that establishing a workable correlation between increasing solar generation and reduced need to hedge fuel is extremely difficult in the short-term. There is potential to have solar resources (and solar production) as a function of utility peak load inform the utility's need to hedge, but we generally anticipate the value to be zero until solar is above 5% of peak load. We currently view distributed solar as de minimis to our need to hedge.

15. There appears to be some agreement that a valuation of avoided RPS compliance should be based on a reduction in load due to increased solar PV generation. Do you agree or disagree that this should be the basis of a value formula and why? Is there a straightforward methodological approach that would generate reasonably accurate values?

Given that residential rooftop PV is ineligible for inclusion in WREGIS, and is therefore not able to generate RECs that can be retired for RPS, a reduction in load is really the only option for estimating distributed solar's contribution to utility RPS compliance. However, if larger projects emerge that are able to generate WREGIS recordable RECs, we believe that should be the basis of a value formula for those customers. Regardless, we believe that viewing an avoided RPS compliance resource from either supply-side or demand-side gets us to largely the same answer.

16. Assuming each utility has enough banked RECs to meet current compliance projects for at least the next five years, how should this value of avoided RPS compliance cost from a newly installed PV system in 2017 be calculated? Should this value be applied only for the future years in which actual deferral of renewable resource procurement to meet compliance will be realized?

We would suggest periodic updates to avoided RPS compliance value. If the Commission elects to have a sufficiency/deficiency period as in the avoided cost QF price, we would suggest not levelizing the avoided RPS compliance value. This may create a situation where a solar system is installed, receives some levelized RPS value immediately, and then even if the system is removed or goes offline before the deficiency period, they have still received some of that deficiency value. The presence of sufficiency/deficiency demarcations should require pricing as seen in the QF avoided cost updates.

It is worth reiterating that in the absence of a REC, the customer's contribution to RPS compliance may be difficult to calculate, levelized or not.

17. Utilities reassess their RPS implementation plans every two years for the next five years. Does this assessment of need have any bearing on the calculation of this element?

Yes. If the Commission decides to include an RVOS sufficiency/deficiency period similar to what currently exists with QF avoided costs, a re-examination of RPS compliance need should be a direct driver of the "avoided RPS compliance" element. Further, incremental solar facilities, as well as resources acquired by the utilities (or lack thereof) could change the value of RPS compliance over time.

18. Is a simplified approach such as what is proposed by E3 reasonably accurate in assessing this value?

E3 suggested a levelized value stream for avoided RPS resources, due to the fact that RPS-compliant resources are generally procured under a long term contract. We do not disagree with this in principle, but we would rather see updates to RPS compliance value as utility need changes. This would not change the price for already procured resources, but would create an additional value for marginal solar resources.
Additionally, if the Commission opts to institute a sufficiency/deficiency period, we do not agree that levelization should occur.

19. Should the Commission consider the possibility of future carbon regulation in valuing solar? Why or why not? What criteria or standards should we apply in making such a determination?

We are not opposed to considering the possibility of future carbon regulation as part of the resource value of solar. However, if future carbon costs are modeled in, we would strongly encourage the Commission to allow utilities to mirror the carbon costs that are currently modeled into the current long-term system planning process. Creating a separate carbon cost projection could create confusion and additional cost.

20. How should we direct utilities to assign probabilities to different energy futures?

PGE advocates for the Commission allowing each utility to mirror the probability modeling that currently exists in the utility's long-term planning process. The futures investigated in the IRP are designed to test both forecasted (reference) and extreme (high and/or low) views of the future with respect to gas prices, carbon prices, load levels, hydro availability, variable renewable output, and capital costs. The high/low futures were created to understand reasonable bounds on potential outcomes. Accordingly, PGE's scenario analysis resembles a form of stress testing in order to understand how portfolios perform under conditions that are extreme relative to forecasted outcomes, rather than a stochastic analysis that seeks to use probability distributions to approximate the likelihood of various outcomes. PGE uses this scenario analysis framework in part because the distributions for key input variables like future natural gas prices and future carbon prices are not well understood. In PGE's view, there is no strong justification to assign different weight any one scenario as more likely than another.

21. Increased solar generation could either increase or reduce (with smart technologies) the need for grid services depending on the specific circumstances. What specific grid services should we focus on? Are the potential benefits and costs location-specific? What additional research or modelling is necessary to properly value grid services?

When included in the system design, large-scale solar generation may have an opportunity to participate in automatic remedial action schemes (RAS) to mitigate transmission system constraints following an unplanned system disturbance. Where applicable, these benefits would be location-specific depending on transmission system needs.
High penetrations of solar could also increase the need for grid ancillary services, including operating reserves, fast-ramping generating units for balancing, and availability of sufficient frequency response to support reliability following an unplanned disturbance. To properly quantify these needs, a region-wide study would need to be undertaken to forecast under what conditions and penetration level s these grid services would need to be supplemented by other means.

22. Parties appear to disagree on the definition of system security and resiliency set forth by E3. What potential resiliency and reliability benefits does solar PV generation potentially provide to the utility system? Are any of those potential benefits captured in other valuation categories? How should these benefits be valued? Is there available data or analysis that would inform an assessment of these values?

In PGE's view (and as stated in rebuttal testimony on July 21, 2016), we do not currently see a system security and resiliency benefit from solar PV by itself. There needs to be ancillary technology associated with a PV system to add a security and/or resiliency benefit (presence of a smart inverter, storage, ability to microgrid, etc.). The ability to island portions of the distribution system on a local level could have value in restoring critical services following extreme events.

23. There appear to be disagreements on valuation when there is uncertainty. What criteria should the Commission use to assign a non-zero or zero value to an element when the value is uncertain?

PGE draws a distinction between an element that is uncertain due to lack of current modeling or agreed-upon calculations, and an element that truly does not provide value to customers. PGE does not currently calculate feeder-level constraint, but we recognize that this element is a value driver and could theoretically provide a benefit to the utility and to our customers. We are willing to accept a proxy calculation/value to determine this amount or to explore a more detailed and accurate calculation.

However, this is separate from elements that we currently view as not adding value (or adding minimal value), such as avoided utility hedging and solar's impact on the wholesale power market. Similar to constraint, we do not have an agreed-upon calculation, but with these elements, we are also skeptical of their value from a more theoretical standpoint. There is simply not a high enough solar penetration in Oregon currently to see either the wholesale power market moving or the mid-term hedging strategy of the company changing. PGE is open to setting up a process to calculate these elements so that if solar prevalence increases in the future, that the potential value can be captured.

24. Should utilities assign values based on the technology of the solar systems (PV with or without smart inverters) that are installed the year a calculation is made?

Yes. The technology of the system could either enhance or reduce its value to the utility. For example, a solar system with a smart inverter would provide system resiliency benefits that a solar system without the smart inverter would not. We believe this approach to be in line with the locational, time-based, and value-stream driven approach suggested by E3.

25. What should we require to obtain location-specific values or reasonable proxies of locational values?

To fully derive capacity values, utilities would need to undertake a feeder-level study of system constraint. This study could involve significant time and financial resource commitments.

26. What should be the time frame for analyses and why? What should be the time period for a levelization calculation?

The time-frame for analyses should depend on the element. Avoided energy and capacity will have yearly calculations, while others (such as a location-specific T&D capacity study) would be updated only periodically. We suggest a yearly update schedule, with the understanding that not every element will be updated every year.

We suggest levelizing over the expected life of the asset as indicated in the depreciation studies for PGE's solar assets. Any levelization should exclude elements that are time based, such as RPS sufficiency/deficiency demarcations.

27. How often should values be updated?

We advocate for an annual update process similar to what is seen for avoided costs currently. Not every element will require a yearly update, but this would create a predictable schedule in which utilities and stakeholders can expect the current value of solar to be updated.

28. What level of granularity and transparency should we require and why?

The level of granularity should depend on the element being calculated. In situations such as marginal energy and capacity, we are able to be granular because as a utility we are able to understand and calculate these values. For new values or values that are not able to be calculated exactly (such as wholesale market changes as a result of solar), we would prefer to avoid situations where a false precision is created.