BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1716

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation to Determine the Resource Value of Solar.

INITIAL BRIEF OF THE ALLIANCE FOR SOLAR CHOICE

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Pursuant to the Administrative Law Judge's Pre-Hearing Conference Memorandum issued November 9, 2015 and Ruling issued August 10, 2016 in the above-captioned docket, the Alliance for Solar Choice (TASC) hereby submits this initial brief.

I. Introduction

TASC's advocacy in this proceeding has focused on ensuring that the methodology developed by the Commission to value solar is based on a solid analytical framework by making certain that adequate standards are in place to guarantee data quality, taking into account the different methodological choices for model inputs, and underscoring the importance of using data with hourly precision. This initial brief supports those arguments and offers TASC's positions on a number of issues identified by parties. TASC commends Commission Staff for their substantial work in creating this tool and we look forward to continued engagement in this proceeding.

II. Issues Identified by TASC

1. Given the Tool's Flexibility, There is a Need to Set Standards for Model Input Quality to Ensure Quality Data is Utilized in Model Runs.

The tool developed by E3 is flexible and transparent. As TASC noted in testimony, while the tool's flexibility is a benefit in that it allows utilities to run the model with information specific to their service areas, this flexibility presents challenges by opening the possibility of the use of sub-par data.[1] There is a risk that the utilities will take varying approaches in developing their inputs due to variations in data availability and methodology. It is therefore necessary for the Commission to establish standards for the quality of data used in the model.

TASC recommends that the Commission develop guidance regarding the inputs used within the tool. The Commission should also acknowledge the risk that using incomplete sets of inputs, insufficiently granular inputs, or inputs derived from sub-par methodologies will fail to yield a comprehensive assessment of the value of solar. As TASC recommended in testimony, the Commission should establish guiding principles for input quality based on three principles: transparency, granularity and completeness.[2]

In order to guarantee sufficient transparency, all datasets used by the utilities should be publicly available. Stakeholders should have the opportunity to review these data sets and propound discovery on the utilities to gain further understanding into the development of the data that the utilities used to populate inputs into the tool.

Where possible, inputs with hourly granularity should be used. Hourly data is necessary to accurately assess the value solar adds to system reliability and deferral of marginal infrastructure investments.

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[1] TASC/100 at p. 3, ln. 7-12.
[2] TASC/100 at p. 4, ln. 2-17.

To ensure completeness, the utilities should be required to populate all avoided cost categories by choosing from a suite of approved methodologies. If a utility has insufficient data to use one of the approved methodologies, the Commission should find that assessment of value to be incomplete and insufficient as a basis for ratemaking. Additionally, avoided cost should not be assigned a zero value merely because the value is uncertain or difficult to quantify.

The Commission should also include societal benefits or, if these benefits are determined to be outside the scope of this proceeding, at least provide placeholders in the tool for these categories of benefits. Importantly, as TASC notes in testimony, Oregon statutory language regarding net metering requires the consideration of "environmental and other public policy benefits" if the Commission decides to limit the utilities' net metering obligations.[3] Including societal benefits, or at least placeholders for those benefits, will therefore be necessary to ensure that the model remains a useful, viable tool for future assessments of NEM successor tariffs.[4]

2. It is Important to Take Into Account the Different Methodological Choices for Model Inputs When Assessing the Reasonableness of the Inputs Chosen.

A number of the inputs for the tool required methodological choices for their development. This is because many of the inputs for E3's model are outputs from separate analyses. It is therefore necessary to consider the separate analyses used in generating these inputs in order to determine whether the inputs are reasonable.

For example, the reliability contribution of solar can be determined using a number of different methodologies. The most accurate approach is to calculate a metric called the Effective Load Carrying Capacity (ELCC), which compares a resource's system reliability contribution to

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[3] TASC/100 at p. 4, ln. 28-30 – p. 5, ln. 1-6 (citing ORS § 757.300(6))
[4] *See Id.* at p. 5, ln. 8-11.

that of a "perfect resource" that would be available at full nameplate capacity 100% of the time.[5] The ELCC requires multiple iterations of a Loss of Load Probability (LOLP) model in order to assess reliability metric under various resource portfolio assumptions. Alternatively, short of a full ELCC analysis, a LOLP model can be used to assign a system outage probability to each hour of the year and then look at the coincidence of solar generation with each outage probability to determine the full contribution to peak.[6]

A utility may, however, use a shortcut approach by looking at the hours with the highest load and assuming that those hours correlate with outage likelihood. Utilities generally look at the top 250 or 150 hours in taking this shortcut approach.[7] In extreme examples, a utility will simply claim that solar's contribution to peak is limited to the amount it would have generated in a single peak hour in the previous year. This last approach is the least accurate, and is problematic in that it fails to acknowledge the uncertainty of when future peaks will occur and disregards the reliability value outside the absolute peak of the year.

There is also tremendous variability in how the year in which resources are needed can be looked at when assessing generation capacity value. For instance, some utilities create forecasts of demand side resources and incorporate those forecasts into their load and resource balance tables. Incorporating such forecasts tends to push out the resource deficiency year, thereby reducing the calculated capacity value for these demand side resources. Staff's response to TASC DR-11 highlighted this potential circularity when the outputs of these models are used as the basis for compensating these resources.[8]

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[5] TASC/100 at p. 5, ln. 30-31 – p. 6, ln. 1-3.
[6] TASC/100 at p. 6, ln. 10-13 (noting that this is the methodology described by Witness Olsen's testimony on pages 30-32).
[7] *Id.* at p. 6, ln. 15-18.
[8] TASC/201 at p. 1.

As the preceding examples illustrate, there is significant variability in the methodologies used to generate certain model inputs. Given this variability, it is important that the Commission take into account the methodologies used when assessing the reasonableness of these inputs.

3. Data Should Use Hourly Precision to Ensure Accurate Assessment of the Benefits Ratepayer Investment in Solar Resources.

While the E3 tool is capable of generating avoided cost outputs with hourly granularity, as Witness Dolezel noted, the tool's ability to achieve this granularity is contingent upon the inputs from the utilities having hourly precision.[9] Although there are certain areas, such as energy cost data, where the utilities tend to have hourly data available, a significant amount of the data provided by utilities was much less granular. It appears, for instance, that the majority of non-energy values could not be calculated based on hourly data.[10] However, in order for the tool to accurately assess the value of solar, it is necessary that, wherever possible, hourly data be used. As Staff noted, in instances where hourly data is unavailable, proxy values can be used.[11]

TASC therefore requests that the Commission provide some form of guidance or create a set of requirements for input data for the E3 model to ensure sufficient granularity and completeness. Doing so can help guarantee that this proceeding benefits from the tool's flexibility while making certain that a sufficient amount of rigor is applied to the development of inputs.

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[9] TASC/100 at p. 7, ln. 12-15 (quoting Staff/100 at p. 6).
[10] *Id.* at p. 7, ln. 19-24.
[11] Staff/300 at p. 17, ln. 17-21.

III. Issues Identified by other Parties

1. TASC Supports Parties' Arguments for Including Additional Benefits Solar is Capable of Providing

A number of parties point out that there are numerous benefits that the tool is not currently capturing. This gap risks an outcome that does not appropriately and accurately value the resource in Oregon. For instance, as the Citizen's Utility Board of Oregon (CUB) noted, the value of solar during low-hydro conditions is not properly captured.[12] Additionally, parties including CUB and the Joint Parties,[13] pointed out that the value of resiliency/security has been left out.[14] The Oregon Department of Energy (ODOE) has also identified several omitted distribution system benefits (e.g., voltage support, frequency ride-through, etc.).[15]

In the California NEM 2.0 Public Tool, E3 provided stakeholders the opportunity to include additional benefits that were not directly quantified in the model. The figure below shows how "other" categories were made available under the inputs tab from the California tool:

Societal Inputs	2015 Value (2015 $)	Esc	Units
Societal Cost of Carbon		5%	$/tonne CO_2
Societal Cost of PM-10		5%	$/lb
Societal Cost of NO_x		5%	$/lb
Externality Costs Related to RPS Assets		5%	$/kW-yr RPS-Qualifying Capacity
Energy Security Cost		5%	$/kWh Thermal Generation
Other		5%	$/kWh Thermal Generation
Other		5%	$/kWh NEM Generation
Other		5%	$/kW-yr NEM Capacity

It is necessary for the RVOS tool to similarly enable stakeholders to model additional benefit categories. This will allow stakeholders to provide reasonable evidence on the record as these value categories have the potential to result in direct avoided costs for the utility.

[12] CUB/100 at pp. 5-6.
[13] Joint Parties include Renewable Northwest (RNW), the Oregon Solar Energy Industries Association (OSEIA), the NW Energy Coalition (NWEC), and Northwest Sustainable Energy for Economic Development (NWSEED).
[14] CUB/100 at p. 6; RNW, OSEIA, NWEC, NW SEED/100 at pp. 4-6.
[15] ODOE/100 at p. 2, ln. 14-24.

2. **The Commission Should Not Adopt PacifiCorp's Recommendation That the Resource Deficiency Period for RVOS be Determined Consistent With QF Avoided Cost Methodology.**

PacifiCorp Witness Dickman argues that "the resource deficiency period of the RVOS should be determined consistent with the methodology, including any changes or updates to the methodology, used to determine resource deficiency for QF avoided costs."[16] The Commission should not adopt this recommendation. Behind-the-meter (BTM) solar, because it is installed onsite and is generally smaller, is not akin to supply-side QFs, but is instead most similar to other customer-side resources such as demand response (DR) and energy efficiency (EE). Given this distinction, in Oregon and other states, the methodologies used to value the capacity from these customer-side resources are justifiably different from that for QFs.

As TASC Witness Gilfenbaum noted, the Commission has approved valuation methodologies that differ from QF avoided cost in other contexts, such as demand response (DR).[17] California has also determined that the capacity from DSM resources should be valued differently than supply-side resources, determining in a recent order that eliminating the concept of the Resource Balance Year (RBY) was appropriate for valuation of DSRs.[18] The CPUC found that "the use of the [RBY] ignores the fact that the short lead times of distributed energy resources add value to the system," and that continuing to rely on the RBY framework "ignores the value of the role distributed energy resources played in past planning decisions."[19] Oregon Staff also notes that using a utility's resource deficiency as the starting point for attributing generation capacity value for existing solar resources is potentially problematic as it

[16] PAC/100 at p. 13, ln. 6-9.
[17] TASC/200 at p. 3, ln. 17-19 – p. 4, ln. 1-16.
[18] TASC/200 at p. 4, ln. 18-21 – p. 5, ln. 1-7 (citing CPUC, Decision 16-06-007, Rulemaking 14-10-003 (June 9, 2016), pp. 12-17).
[19] CPUC, Decision 16-06-007, Rulemaking 14-10-003 (June 9, 2016), pp. 12-17.

creates a "circularity" in the valuation process.[20] However, Staff states that the potential circularity is not relevant because "the current calculation of RVOS will not be used directly in formulating compensation for behind-the-meter solar at this time."[21] This reasoning appears to acknowledge that the current methodology is inappropriate for assessing compensation for BTM solar. Given that PacifiCorp, has indicated they believe the RVOS methodology should be used to determine compensation for BTM solar[22] and Staff identified the RVOS as the "means to value solar generation, whether it is from a solar farm or rooftop array,"[23] it is critical that the Commission clarify now that the methodology will not be used directly for formulating compensation.

3. Deployment of Solar Resources Produces Widely Recognized Transmission & Distribution Benefits

The utilities appear to reject the idea that rooftop solar can avoid or defer capital spending on transmission and distribution (T&D) capacity expansion, and argue that there is insufficient data to calculate or even admit the existence of this benefit. However, they present only vague assertions to counter what is a commonly understood benefit of customer-sited distributed generation (DG). Despite the lack of granular hourly load data at the substation or circuit level, reasonable proxies can be used. For example, the marginal transmission and distribution cost values utilities develop as part of their rate cases can be allocated to specific hours through LOLP or Probability of Peak Analysis. Alternatively, the top 100 or 150 system load hours can serve as a proxy, by giving those hours a load-weighted allocation, normalized to

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[20] TASC/200 at p. 5, ln. 9-20 – p. 6, ln. 1-12.
[21] TASC/200 at p. 5, ln. 9-20 – p. 6, ln. 1-12.
[22] PAC/11 at p. 4.
[23] OPUC Staff, Draft Solar Incentive Report, UM 1758 (July 28, 2016), at p. 11, *available at* http://edocs.puc.state.or.us/efdocs/HAH/um1758hah143737.pdf.

a total of 100%. Simply put, even if the ideal data is unavailable, using a zero value for a particular category is not justified or reasonable. As Staff has noted, in the absence of more specific, granular values measuring avoidable T&D costs, the Marginal Cost of Service Study (MCOSS) can provide a basis for average T&D costs.[24]

TASC further agrees with Staff's observation that, for the benefits of DERs to be fully realized, T&D planning must evolve to include "non-wires" alternatives. Failure to take into account the potential of non-wires alternatives creates a barrier to realizing avoided T&D benefits. As a result, regulators have begun to emphasize the need to consider the potential contributions of non-wires alternatives. For instance, the Federal Energy Regulatory Commission (FERC) has underscored the need for "comparable treatment" of non-wires alternatives in transmission planning.[25] California has codified the consideration of non-wires alternatives, requiring that the California Public Utilities Commission

> consider cost-effective alternatives to transmission facilities that meet the need for an efficient, reliable and affordable supply of electricity, including, but not limited to, demand-side alternatives such as targeted energy efficiency, ultraclean distributed generation . . . and other demand reduction resources.[26]

California is already seeing the benefits of this mandate: the California Independent System Operator's (CAISO) most recent transmission plan calls for cancelling $192M of previously approved transmission upgrades that can now be avoided thanks to EE and DG.[27]

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[24] TASC/202 at p. 1.
[25] *See* FERC Order 1000 (2011); FERC Order 890 (2007).
[26] Cal. Pub. Util. Code § 1002.3.
[27] CAISO Board-Approved 2015-2016 Transmission Plan (Mar. 28, 2016), at p. 13, *available at* https://www.caiso.com/Documents/Board-Approved2015-2016TransmissionPlan.pdf; J. Pyper, *Californians Just Saved $192 Million Thanks to Efficiency and Rooftop Solar*, Greentech Media (May 31, 2016), *available at* http://www.greentechmedia.com/articles/read/Californians-Just-Saved-192-Million-Thanks-to-Efficiency-and-Rooftop-Solar.

A number of jurisdictions have also focused on non-wires alternatives in the distribution context by seeking ways to remove the financial disincentive utilities have to avoid building new infrastructure. As Witness Olson highlighted, California and New York are both seeking ways to integrate DERs into the planning processes behind distribution investment decisions and are seeking ways to ensure DERs are compensated based on the value they provide in this context.[28] TASC encourages the Commission to look to these and other jurisdictions that are seeking to better incorporate non-wires alternatives into T&D planning.

PGE argues that avoided T&D benefits should only apply to solar systems that are "capable of reliably delivering output during a system peak event . . . and are large enough, in aggregate, to defer the needed capacity."[29] The only reason to support this narrow requirement is to support PGE's notion that the T&D benefits of solar are zero. This view is not supported by the realities of T&D planning. In fact, a fleet of aggregated DERs offers reduced risk of outage for the same amount of installed kWs at a single large system due to the DERs' added geographic diversity. It is therefore reasonable to look at the fleet of distributed solar generators in aggregate, and determine the capabilities and benefits of the fleet as a whole. Given the uncertainty regarding the timing and duration of peak, a probabilistic approach is warranted.

PGE also states that LOLP is not the correct data to value the avoided T&D benefit, but that hourly usage data by feeder is the proper data for measuring peak usage and accurately estimating this benefit.[30] If available and complete, such feeder-specific data could be appropriate for determining the avoided T&D benefits. However, if a full dataset of feeder-specific data is not available, it would also be appropriate to use LOLP to develop a proxy value

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[28] *See* TASC/203 at p. 1.
[29] PGE/100 at p. 11, ln. 6-10.
[30] PGE/100 at p. 11.

in the absence of circuit-level load data. Although LOLP may be more typically used to evaluate system reliability metrics and the need for additional planning reserves, LOLP provides a solid high-level assessment of the range of hours where the system is most likely to be stressed. In the absence of more granular load data, it is a reasonable proxy for allocating the avoidable marginal costs to specific hours. Again, because reasonable proxy values can be developed using available data, the absence of ideal data is not a sufficient reason to assume a benefit category is zero.

PacifiCorp also recommends that "a symmetrical component of the calculation should be included: costs associated with accelerated transmission and distribution investments."[31] However, PacificCorp provides no concrete example or analysis of these costs. While it is theoretically possible that, in cases where non-wires alternatives are unavailable, additional T&D costs can be incurred from high penetrations of DG solar on certain circuits, planners often have alternative solutions at their disposal that can mitigate these issues at low cost. For example, SolarCity's grid engineering team has produced a paper that explains a number of common mitigation solutions utilities propose to address perceived issues with high-penetration circuits and provides alternative solutions that offer the same reliability benefits at little to no cost.[32] These solutions include changing settings on existing protection equipment or providing the same reliability benefits with smart inverters.[33] Therefore, before trying to quantify a "symmetrical" cost component, non-wires alternatives should first be considered.

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[31] PAC/100 at p. 14, ln. 2-5.
[32] *See* SolarCity, Technical Brief on Utility Mitigation Requirements, *available at* http://www.solarcity.com/company/distributed-energy-resources#.
[33] *Id.*

4. Solar Generation Provides Clear RPS Value by Reducing the Retail Load on Which the RPS Obligation is Based.

PacifiCorp and PGE argue for disregarding the RPS compliance value provided by distributed solar generation. PacifiCorp Witness Dickman states that "to the extent distributed solar generation does not provide the utility with RPS value, the value should be zero,"[34] while PGE Witnesses Brown and Murtaugh argue that the benefit would only apply "if the RPS compliance is truly avoided and PGE gets the RECs from the solar production."[35] These statements fundamentally misunderstand the RPS value category. The benefit does not come from directly providing eligible RECs, but rather from reducing the retail load on which the RPS compliance obligation is based.[36] As TASC Witness Gilfenbaum noted, "To the extent that contracting with RPS-eligible generators leads to above-market costs, the lower retail sales would reduce the cost of the RPS compliance by (above market costs * the RPS %)."[37]

5. Zero-Carbon Energy Resources, like Solar, Produce Carbon Compliance Benefits That Must be Modeled to Ensure an Accurate Depiction of Solar's Value.

PacifiCorp Witness Dickman argues that carbon compliance benefits "should either be excluded or set at zero."[38] This position ignores industry best practices of making reasonable assumptions to represent future conditions in long-term planning. Simply because these benefits cannot be realized today under current planning frameworks and regulatory regimes does not mean they should be assumed to be zero for the entire 25 year planning horizon.

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[34] PAC/100 at p. 14, ln. 10-12.
[35] PGE/100 at p. 5.
[36] *See, e.g.*, ORS § 469A.052.
[37] TASC/200 at p. 14, ln. 9-11.
[38] PAC/100 at p. 5, ln. 7-9.

There is a high likelihood of carbon compliance being implemented on the planning horizon. PacifiCorp has acknowledged this fact by modeling in its most recent IRP a number of scenarios that take into account potential Clean Power Plan rules as required by the Commission's 2015 IRP order.[39] PacifiCorp also listed in a recent stakeholder presentation several Oregon-specific GHG regulations that could impact the costs of future resource portfolios, including a 1,100 lb CO_2/MWh emission performance standard, and the Clean Electricity and Coal Transition Plan (SB 1547) designed to ensure electric sector GHG reductions.[40] It is therefore reasonable, based on industry best practices and PacifiCorp's own modeling in other contexts, to reject requests to set carbon compliance benefits at zero.

6. Ancillary Services Benefits and Renewable Integration Costs Should Be Separate and Distinct Value and Cost Categories to Ensure Transparency.

TASC agrees with a number of parties, including Joint Parties and ODOE, who argue that ancillary services and integration costs should be separated into distinct value and cost categories.[41] The ancillary services benefits of solar stem from the fact that distributed resources can reduce the need for a balancing authority to procure ancillary services by reducing retail load. Renewable integration costs are meant to capture any increase in operation costs required to manage the intermittency of incremental renewable generation. Despite the differences between ancillary services and integration costs, the RVOS methodology currently combines these two categories. TASC Witness Glifenbaum noted in testimony that E3 has separately included the reduced need for ancillary services in previous studies, citing examples in California

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[39] PacifiCorp, 2015 Integrated Resource Plan vol. 1, OPUC Docket No. LC 62 (Mar. 31, 2015), at pp. 28-29, *available at* http://edocs.puc.state.or.us/efdocs/HAA/lc62haa125914.pdf.
[40] PacificCorp, 2017 Integrated Resource Plan, Public Input Meeting 2 (July 20, 2016), http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/PacifiCorp_2017_IRP_PIM02_7-20-16.pdf.
[41] RNW, OSEIA, NWEC, NW SEED/100 at p. 7-8; ODOE/200 at p. 7, ln. 18-21 – p. 8, ln. 1-11.

and Nevada.[42] For a robust and appropriate valuation of the resource in Oregon, the same approach should be used here in Oregon.

IV. Conclusion

TASC appreciates the opportunity to provide this initial brief and looks forward to addressing the issues identified above in this proceeding.

Respectfully submitted,

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[42] TASC/200 at p. 17, ln. 8-20.