OREGON SOLAR + STORAGE INDUSTRIES ASSOCIATION

Oregon Public Utility Commission
201 High Street SE, Suite 100
Salem, OR 97301-3398

October 20, 2021

Re: Docket No. UM 2011, Comments on staff proposal for capacity valuation best practices

Oregon Solar + Storage Industries Association (OSSIA) respectfully provides the following comments regarding staff's updated "Capacity Valuation Best Practices" document.[1] OSSIA appreciates staff's ongoing efforts to refine its straw proposal on capacity valuation, and to incorporate stakeholder feedback. OSSIA's general comments on these issues have not changed from prior rounds of comments. In these comments, OSSIA briefly summarizes some of the points it considers to be most important.

1. Staff's Best Practices Methodology Should Apply to a Broad Range of Use Cases

The purpose of this docket was and has been to broadly investigate capacity valuation methodologies to create a comprehensive approach to capacity and harmonize how capacity is assessed across several dockets. In this most recent proposal, Staff proposes a more limited use. These best practices would only apply when assigning a capacity value "outside of an Integrated Resource Plan [IRP] portfolio analysis, Request for Proposals [RFP] under Division 89, or Resource Adequacy Program(s)" in such situations as "PURPA resource avoided capacity cost determinations, energy efficiency cost effectiveness, demand response cost effectiveness, storage pilot cost effectiveness, resource value of solar determinations, and voluntary green tariff development and procurement."[2] This more narrow scope is concerning:

First, the use cases for which Staff proposes to use these best practices should be based on what the utility is acquiring or avoiding. For example, the PURPA resource avoided capacity cost must be based on the utility's actual avoided cost. If the utility uses a different methodology in its own resource planning and procurement decisions, then it can arrive at different results and the PURPA avoided cost will be inaccurate. This same logic applies to other use cases evaluating the cost effectiveness of other supply or demand side resources (energy efficiency, demand response, etc.) because the cost effectiveness of those resources will change if the utility's procurement plan or decision changes.

Second, excluding the IRP and RFP from using these best practices will create an incentive for gaming the values to advantage utility resources over these other use cases. This docket should strive for common sense solutions. If the same methodology applies more broadly, than there is an incentive to develop a common-sense solution. Afterall, this is a "best practices" document, and there is no reason why such best practices should not apply in the broadest scope possible.

[1] https://edocs.puc.state.or.us/efdocs/HAO/um2011hao164626.pdf
[2] UM 2100 Staff Capacity Value Best Practices – Updated Draft (Sept. 30, 2021).

2. Use a uniform three-year ramp-up period

Staff continues to propose a three-year ramp period for Portland General Electric (PGE) and Pacificorp (PAC), but has proposed a 5-year ramp period for Idaho Power Company (IPCo), rather than the 10-year ramp period that was included in staff's July 2021 straw proposal. While a 5-year ramp period is (1) more closely aligned with the proposed 3-year ramp period for PGE and PAC, and (2) a significant change from the 10-year IPCo ramp period that staff had initially proposed, OSSIA believes there is not a compelling reason to adopt different periods for each utility.

Staff proposes that ramp periods should be based on each utility's acquisition rate of major resources, which it defines as a resource larger than 80 MW in size. Staff appears to propose this size based on Oregon Public Utility Commission (OPUC) Rule 860-089-0100, which requires competitive bidding rules for utility projects or groups of projects above this size.[3]

IPCo issued a request for new electric capacity resources (RFP) In June 2021.[4] The RFP states that the "need for additional capacity resources has been identified as early as summer 2023 at up to 80 MW." Thus, IPCO needs to add as much as 80 MW of new capacity within two years. There is clearly nothing magic about the 80 MW size guideline, and no reason why IPCo should be treated differently than the other two IOUs simply because its near-term need is "up to" 80 MW.

Staff's proposes reconsidering the adopted ramp period in 2026. We recommend staff clarify whether the basis for a "three-year" ramp period is a capacity need starting in year four or in year three. OSSIA agrees that periodic reconsideration, such as staff's proposed period of "no less than once every three years" is reasonable.

Given that IPCo is in the midst of an RFP now that would add the equivalent of a major new resource within the period of time that staff is proposing for the PGE and PAC ramp period, OSSIA continues to recommend adopting a uniform three-year ramp-up period for all three utilities.

3. Do not assume the current value of capacity is zero.

Staff's proposed value of capacity during the ramp up period transitions from 0% to 100% value. OSSIA continues to recommend recognizing that capacity value exists today, even when there is no immediate need for new capacity; it does not have zero value. Capacity values should transition during the ramp-up period from the current value of capacity, rather than from a zero value to the 100% value of new capacity that is assumed after the end of the ramp period. While staff's sub-bullet 8 c. appears to support this approach it is unclear what is meant by "the estimated capacity contribution value of that resource absent ramping in that year". Please provide clarification, preferably in the form of an example.

[3] See https://oregon.public.law/rules/oar_860-089-0100
[4] See https://www.idahopower.com/about-us/doing-business-with-us/request-for-resources/

The Commission's UM 2143 investigation into Resource Adequacy (RA) may result in a short-term capacity value that could be used, instead of a zero value, in order to identify the average cost of RA capacity that is incurred by the utilities in order to achieve an adequate level of resources needed to ensure reliability. OSSIA's prior comments have identified, for example, regular California utility RA reports that indicate these values.[5] In fact, the California Public Utility Commission (CPUC) has now adopted Qualifying Facility (QF) pricing for projects under 20 MW in size, which is based on RA contract costs.[6]

We note staff's straw proposal in UM 2143[7] considers that utility information filings may "reveal need for urgent, binding action to ensure near-term RA" in the state. Clearly, it would not be consistent to simply assume that the current capacity value is zero, if it turns out there may be an urgent need for capacity. OSSIA recognizes that the RA program in Oregon is still in development, but it is reasonable to assume such a program will bring more transparency to current capacity values. For example, the RA program could include informational utility filings regarding the average annual costs of RA procurement. Such filings should indicate, in addition to the amount of RA procurement, the average cost of RA procurement. Thus, RA programs are not limited to the issue of how much capacity is needed to ensure reliability.

As another source for near-term capacity value, in most wholesale electric markets in the U.S., there is at least a bilateral market for short-term capacity. FERC's Electric Quarterly Reports (EQR) or FERC Form #1 data on purchased power may be possible sources for this information, for example by looking at the extent to which firm energy purchase prices exceed energy market prices.

4. Base the capacity value on resources that are most likely to be built.

Staff proposes that a utility's least-cost capacity addition must reflect a resource that is reasonably available, and able to operate and deliver to the utility's Oregon jurisdiction, in compliance with state policy. A net cost of new capacity would be calculated, and energy rents ("dispatch benefit") would be removed from the levelized cost of capacity.

We would add that the avoided capacity resource should also represent a pure or "perfect" capacity resource. As noted in staff's document, the Effective Load Carrying Capability (ELCC) metric is based on a determination in which "perfect" capacity is removed, and capacity for a particular type of resource is added until the original level of system reliability is restored. Since the ELCC is thus a metric that determines how close a particular resource is to being perfect, the avoided least-cost capacity resource used to determine capacity value should be a resource with close to 100% ELCC value. To the extent the

[5] See Table 6 of California's 2019 annual RA report, at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2019rareport-1.pdf.
[6] For example, see PG&E Advice 6138-E, implementing CPUC Decision 20-05-006, at https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_6138-E.pdf
[7] https://edocs.puc.state.or.us/efdocs/HAH/um2143hah145744.pdf

perfect resource has less than 100% capacity contribution, we note it may be necessary to apply an ELCC ratio that includes the ELCC for the avoided capacity resource in the denominator, so that ELCC value for the specific resource being valued is in comparison to the ELCC value for the avoided or "perfect" capacity resource.[8]

PAC's 2021 Integrated Resource Plan (IRP) indicates[9] that, within three years (i.e. by the end of 2024), the preferred portfolio includes the resources obtained from the 2020 All-source Request for Proposals (RFP), including 497 MW of battery storage paired with solar and a 200 MW stand-alone battery. PAC's 2021 IRP also notes that, through 2026, the preferred portfolio includes an additional 600 MW of solar co-located with storage.

Clearly solar plus storage hybrids are a dominant feature of the expected future capacity procurement by the Oregon IOUs. Thus, OSSIA continues to recommend the proxy capacity resource should be assumed to be utility-scale battery storage, co-located with solar PV or charged with off-peak grid energy.

OSSIA supports staff's proposal to include the cost of any new transmission facilities that would be required in order to deliver the output of the new proxy resource to the utility's Oregon jurisdiction. OSSIA notes however that if the new transmission facilities cannot be built within the timeline of the identified capacity need (i.e., capacity is needed in 3 years, but transmission will take 10 years to build), then the resource is not "able to operate and deliver" to Oregon load in conflict with Staff's above-identified principle. In such a situation, another resource would need to be identified that is either closer to load and does not rely on the transmission facility or relies on transmission buildout that can deliver to Oregon load.

5. Hourly LOLP data to support annual ELCC calculations

OSSIA strongly supports staff's proposal to augment annual ELCC values with hourly LOLPs. As described in prior comments, OSSIA believes that hourly values can give guidance and comfort to projects that their annual ELCC determinations are reasonably accurate. For example, if a project applies its hourly output profile to the 8760 set of LOLPs that is provided concurrent with ELCC reporting, the annual weighted average LOLP value should not be extremely different than the ELCC value. In addition, hourly LOLP values provide an indication to generators as to the hours in which capacity is most valuable.

[8] For example, PAC's 2021 IRP, at appendix K, indicates a 74% summer and 90% winter capacity contribution for 4-hour storage. See page 2020 of https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20II%20-%209.15.2021%20Final.pdf. Similarly, PGE's 2021 IRP update shows a 4-hour battery storage marginal ELCC no higher than 84%.

[9] At page 8 of https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf

OSSIA is also interested in staff's proposal to allow utilities to utilize 8760 LOLP values as an alternative method to ELCC modeling, to the extent an ELCC determination by a utility is not practical. However, OSSIA is concerned that such a methodology would not adequately capture the dynamic nature of hybrid and storage resources. With solar and wind, you can define a fixed shape for the resource and model that against the LOLP value. However, hybrids and storage resources are not as easily captured in a fixed shape. This is so because hybrid and storage resource can respond dynamically to market signals. For example, it could charge in the morning one day or in the early afternoon another day if it can capture a better value by operating in that manner. It is more difficult to approximate a fixed shape for such a resource. Given that hybrids and storage resources are and will continue to play an important (and likely leading) role in our energy future, these resources should not be discouraged.[10] An ELCC methodology is better able to capture these dynamic effects. Before utilizing an alternative method, the utility should bear a high burden to demonstrate that the ELCC is not practical from a workload perspective, and perhaps should simply hire additional staff or bring on additional resources in order to ease that workload.

OSSIA further recommends that, in the interest of ensuring that 8760 LOLP values and resource specific ELCC values remain consistent, generation projects should have the choice as to whether to utilize hourly LOLP values, instead of annual ELCCs that incorporate expected hourly generation, for the determination of their capacity value. While it is impossible for a generator to know, based on single ELCC values, how to change its output profile to improve its capacity value, an 8760 set of LOLP values would allow projects that include storage to alter their output profile in order to maximize their LOLP weighted average capacity factor. In addition, models such as the Resource Value of Solar (RVOS), should continue to use 8760 LOLPs for capacity allocation, instead of an opaque ELCC value.

OSSIA appreciates staff's attention to these comments.

Sincerely,

Angela Crowley-Koch

Executive Director

[10] For example, we note that the methodology adopted in California for evaluating the qualifying capacity (QC) of hybrid resources is based on the sum of (1) the discharge capacity of energy storage, adjusted downward to the extent the renewable resource is unable to fill storage two hours prior to the net load peak, and (2) the QC of the "remaining" renewable capacity, net of the capacity required to charge the battery, times a monthly ELCC factor. See page 30-31 of Decision 20-06-031, at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M342/K083/342083913.PDF.