BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2005

In the Matter of	)
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Oregon Public Utility Commission,	)
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Distributed System Planning Process.	)
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RESPONSES OF THE OREGON CITIZENS' UTILITY BOARD

FOR AUG. 25, 2020, SPECIAL PUBLIC MEETING

August 20, 2020

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In the Matter of Oregon Public Utility Commission, Distributed System Planning Process.	))))))))	THE OREGON CITIZENS' UTILITY BOARD RESPONSES TO STAKEHOLDER QUESTIONS FOR AUG. 25, 2020, SPECIAL PUBLIC MEETING.

1. What kind of actionable baseline data and system assessment information should be included in the first utility DSP plans in order to help parties reach a shared understanding of the current state of the distribution systems?

a. Information on the components of the distribution system within the utility's service area.
b. Peak load and load curves by customer type, customer energy usage, both current and forecasted.
c. DER projections.
d. System upgrade requirements.
e. Projected costs and benefits of system upgrades and new distribution system investments.
f. Utility possession and planned adoption of advanced grid technologies and their cost-effectiveness.
g. Customer level data (if available) including proximity to adopters, customer engagement, home size, EV ownership, and others.

2. When considering the first utility DSP plans, is a "bottom-up" DER/EV forecasting methodology worth the likely additional cost when compared to a "top-down" forecasting methodology? Why or why not?

The adoption of a particular methodology would depend on data availability. While obtaining more granular data at the customer level would incur additional costs it would lead to much improved DER forecasting.

At present it appears that top-down models such as the Bass Diffusion Model is widely used by utilities for the purpose of DER forecasting. While this model has been found to yield considerably accurate outcomes at the macro level, this model fails to account for impacts of individual customer level predictive variables like proximity to other adopters, home size, customer engagement data, etc. Utilities would need detailed customer level data to provide forecasts at this level of granularity. An improved way to forecast DERs would be to be able to plan for impacts of DERs at the feeder level and below, to continuously learn from customers in a dynamic DER market and account for the interdependence nature of DER adoption.[1]

With respect to cost, adopting already existing models might be cost effective. However, if the Oregon DSP is going to be more "human-centric" or community-impact based, it would make sense to adopt a "bottom-up" DER/EV forecasting methodology. It is, therefore, essential to know if utilities have suitable and sufficient data at the customer level, for instance, from smart meters to be able to conduct such an analysis. All electric utilities in Oregon have 90-100% deployment of AMI in their service area and that data should be used exhaustively.

However, for the first DSP filings, if utilities are cost and data constrained, they can start with a top down approach but later transition to a "bottom-up" approach as more customer level data become available.

3. **When considering the first plans utilities file, what are likely to be the best uses for HCAs, and in what ways would your organization use them? For example, to screen projects (as a partial substitute for interconnection studies)? To help utility customers understand the general state of their feeder? For researching the overall opportunity for DERs in a given area?**

HCA appears to be a key element in DSPs. As consumer advocates our goal would ensure that HCA is applied strategically, prudently and towards the benefits of all energy consumers. HCA should be required to the extent that there is a genuine need for this analysis and that the analysis generates net benefits for customers. Transparency is key to understanding a utility's application of an HCA.

CUB would be using HCA findings to:[2]
i. Understand DER investment opportunities in a given area.
ii. Ensure that DERs are incorporated and reflected in future grid investment and planning.
iii. Understand how the HCA could inform DER forecasting and locational valuation to identify to evaluate benefits of DERs based on their physical location on the grid and

1 https://www.cleanpower.com/2018/forecast-der-adoption/

2 https://www.utilitydive.com/news/why-are-the-newest-distribution-system-buzzwords-hosting-capacity-analysis/514219/

performance characteristics. The analysis should evaluate the cost effectiveness and prudence of DER investments on the utility's system.

What form of data presentation would your use benefit from (e.g. raw, tabular data or visualized on a map)?

Both maps and tabular data would be useful. While maps are visual tools and easier to interpret, tabular data showing minimum and maximum hosting capacities at the feeder level would be useful to understand the full potential of installing DERs.[3]

This is a helpful source on HCA
https://irecusa.org/2018/10/the-evolution-of-hosting-capacity-analysis-as-a-grid-modernization-tool/#:~:text=Hosting%20capacity%20analysis%20(HCA)%20is,rooftop%20solar%20and%20energy%20storage.

4. **How could a Community Engagement Plan and process lead to improved distribution project outcomes for residents, business owners, and stakeholders in impacted areas?**

Several stakeholders including CUB are concerned about impacts of DSP projects on communities who are also utility customers, and especially the ones that are underserved. Additionally, customer needs must be adequately reflected in DSP projects for efficient and increased DER integration. Community engagement could also be used to identify specific locations to install community-DERs based on the specific needs of a community. Customer engagement and value lie at the heart of DSP. Hence planning for community engagement would be critical for the successful implementation of a distribution system project.

A CEP would document the needs for and the impacts of specific projects on local communities. This would be an immensely useful resource for both utilities and regulators.

When should community engagement around a project begin? What is a practical "project threshold" to determine which projects warrant this?

Identification of communities and an assessment of community needs and impacts must be performed prior to designing a specific project.

What metrics, evaluation and reporting should be required?

Metrics may include but not limited to service reliability, energy burden, environmental, and health impacts.

3 XcelEnergy 2016 DSP Study.

For example, recently Avista Corporation, in their ongoing 2021 IRP process, presented a map showing community impact. The study identifies highly impacted communities and vulnerable and non-vulnerable populations (based on Washington State's Health Disparities map). The utility has calculated several IRP metrics such as Energy usage per customer, Cost per Customer and Preference for vulnerable communities relative to non-vulnerable ones. Similarly, they have also calculated Reliability and Resiliency metrics for each distribution feeder and matched it with communities, estimated potential benefits of specific distribution projects for areas and made comparisons between communities, and so on. They have also performed resource analysis including environmental impact, economic and reliability benefits and energy security analysis separately for vulnerable populations and highly impacted communities.[4]

Similar evaluation methods could be used for electric utilities participating in Oregon's DSP.

How might the PUC support utilities to develop and showcase projects co-created with community partners?

The PUC might facilitate increased interaction of utility and stakeholders with local community-based organizations. There could be a web-based public forum for communities to participate in a specific DSP project.

The utilities could have an outreach and education budget tied to projects that are co-created with the community.

In addition to the filed DSP, utilities should report on the status and use cases of various DERs installed on an annual or semiannual basis.

5. In what ways do stakeholders foresee DSP affecting utilities' current business model? Do these represent incentives to pursue DSP, or barriers?

It is important to recognize the utility's system needs and the model required to acquire that. The effect on the utilities' current business model depends on this needs-analysis.

The utilities are essentially seeking flexibility in their system. The DSP would help them achieve that in the most cost-effective manner. It is a different engineering model but may be well accommodated within the current business model. Utilities have incentives to invest in DERs or customer-resources in order to acquire flexibility. The current

[4] AVISTA 2021 IRP TAC 2 presentation slides
https://www.myavista.com/about-us/integrated-resource-planning

business model should not be problematic if cost-benefit analyses suggest that there are capital investments to be made in bringing DERs to the utility's system.

However, the current business model could be problematic if DERs are more cost effective when not utility owned. In that instance, the utilities would likely see this as a barrier to pursue DSP. Also, DERs will defer the need for large capital investments in generation and transmission. This is also likely a barrier to widespread utility adoption.

Are there any changes that need to be made to Oregon's approach to regulation in order to succeed at advancing DERs cost-effectively?

At this point it is unclear what specific changes would need to be made. In the DSP, we should strive to capture all value streams associated with DERs. To the extent that we can, DERs will be increasingly cost effective. This should include carbon pricing scenarios and potential avoided investment. We recognize the need to look at DSP differently from traditional investment planning, in the presence of DERs including demand-response, battery storage, rooftop solar, etc. At present it is not known what investment model is at the back end of building this new system.

Which barriers and uncertainties to long-term DSP are most significant from your perspective?

Cost allocation may be an issue with multi-state utilities' cost recovery. Distribution system is assigned to one state, but the capacity is assigned to the system as a whole.

6. What are your reactions to the overarching goals below? How are your needs reflected or missing? Do you recommend changes?

CUB appreciates the comprehensiveness of PUC's overarching goals for Oregon's DSP. The customer focused nature of these goals reflects CUB's needs. In particular, the goals address various customer-centric issues including customer choice and affordability, cost allocation as well as inclusion and equitable access. CUB also appreciates the inclusion of transparency and environmental issues in the set of long-term goals.

CUB would also like to point out that an important goal of DSP would be to plan for and provide flexible capacity that would be needed on a mostly renewable system. Although this might be implied in the already stated goals, it would be useful to include it explicitly as a goal.

Dated this 20th day of August 2020.

Respectfully submitted,

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