Oregon Solar Energy Industries Association

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

Re: INVESTIGATION INTO DISTRIBUTION SYSTEM PLANNING
Oregon Solar Energy Industries Association Responses

August 30, 2019

Oregon Public Utility Commissioners and staff,

Below please find OSEIA's responses to the UM 2005 questionnaire.

1) Commission principles for distribution system planning: a) What principles should the Commission adopt? Please explain and define.

The principles that should inform distribution system planning (DSP) should include the following:

1) Minimizing over-all electric system costs including operating costs such as transmission and distribution line losses while maximizing ratepayer and societal benefits from investments in distributed energy resources (DERs).
2) Supporting the state's goals for decarbonizing the electricity sector and the overall economy, including the transportation system.
3) Modernizing the electric distribution system to accommodate two-way power flows from DERs while maintaining or improving reliability.
4) Enabling customers to choose technologies that reduce environmental damage while improving their security, comfort and control over energy usage.
5) Creating opportunities for DERs to provide energy and essential reliability services at both the distribution and bulk power system levels.

b) What level of specificity is most helpful to include in principles?

It is important that the DSP principles be articulated in a manner that enables the development of specific metrics that can be used to monitor concrete outcomes over time. It is also important that the principles be incorporated into an overall vision for each utility that will guide long-term (e.g. 10 years) resource planning, capital investment and procurement of grid services. The

utilities should put forward specific measurable objectives for each of the adopted principles that then would be subject to stakeholder review for inclusion in each utility's Plan.

The DSP process should be designed to encourage DER providers and other stakeholders to participate in the formulation and review of each utility's DSP. The DSP process should be structured so that it both informs and responds to Integrated Resource Plans.

2) Maximizing customer value: a) How you would define "maximize customer value" in the context of distribution system planning?

The definition of "maximize customer value" should take a societal perspective and should include the cost of electric service in the aggregate, the levels of system and local reliability and resiliency desired, and a cost-effective trajectory to reduce greenhouse gas emissions and local air pollutants. The definition should also recognize that individual customers have varying values and should support opportunities for customers to choose technologies that meet their needs and match their values. The DSP needs to achieve a balance between increasing societal benefits while protecting individual values in managing energy use.

b) What considerations (from Staff whitepaper or other thoughts) are most important to focus upon when maximizing customer value in planning for the distribution system?

The staff expectation that the DSP process will enable utilities to clearly identify distribution system needs and then evaluate a range of alternative solutions (including the use of DERs) is a reasonable focus. Distribution system planning and operations should evolve over time guided by the DSP process to become more transparent, rigorous, interactive and advanced.

Of these four identified attributes, transparency and interactive participation are the most important areas to focus on during the early stages of DSP development. Creating a shared common understanding of future distribution system constraints and needs will be important for all stakeholders in developing best-fit solutions.

The DSPs should present information about system needs in multiple formats (narrative, tabular, graphic) to stakeholders including through the promulgation of distribution system maps.

A distribution system-wide hosting capacity analysis should be one of the early deliverables included in the Plans. It is important that DER developers understand the capability of the distribution system to accommodate the interconnection of solar, storage and other devices to the grid. The updating of the hosting capacity should be interactive and frequent so that bottlenecks in planning for new projects are minimized. An effective hosting capacity analysis

should lessen the cost of interconnection, avoid the need for network upgrades and reduce transactions costs for DER developers.

Likewise development of a common methodology for evaluating the locational benefits of DER deployment should be emphasized. Optimizing locational benefits will be an iterative process that should engage multiple stakeholders. As load profiles shift circuit-by-circuit with the adoption of electric vehicles and electric space and water heating, locational net benefits analysis will be increasingly valuable in avoiding costly distribution system upgrades and leveraging the development and operation of DERs.

Rigorous advanced methodologies to evaluate alternative solutions will become increasingly important over time but need to be developed in an interactive manner that is responsive to environmental policies and community interests. A good DSP process should facilitate local communities in the development of local resources that improve air quality and provide local economic benefits. It can also be an important tool in reducing greenhouse gas emissions over time.

Utilities will need to invest in grid modernization that includes engineering and software planning tools, improvements in distribution and outage management systems, advanced communications and cybersecurity as well as more grid automation. It is important that these investments be sequenced appropriately to accommodate the growth of DERs while minimizing rate impacts. Premature investment in grid modernization will not be cost effective and can increase the risk of technology obsolescence.

3) Evaluation of utility distribution system plans: a) Which criteria or metrics should the Commission use in evaluating the proposed distribution plans (Plans)?

Traditional reliability criteria like SAIDI and SAIFI should be part of the Plans as should cost effectiveness metrics. Environmental criteria like reductions in greenhouse gas emissions and air pollutants should also be used in evaluating the effectiveness of the Plans. Metrics for the interconnection experience and DER asset utilization should also be developed for inclusion in the Plans. The Plans should lay a foundation for transportation electrification and the emerging concern of improving community resilience.

b) How will your organization evaluate and/or otherwise use the proposed Plans?

OSEIA will evaluate the plan based on the uptake of distributed solar and paired solar plus storage systems by residential and business customers in each utility's service area. The development of community solar and solar plus storage systems interconnected to the

distribution system will also be an important metric. Interconnection turnaround time should also be measured. Linkage of the hosting capacity analysis with processing of interconnection applications will also be important objective of OSEIA. We expect that the duration of the interconnection study process would be lessened and the cost of interconnection reduced. The Plans should take into account the capabilities of smart inverters to support the management of voltage on the distribution system. Smart inverters can also provide data to the utilities to improve their situational awareness and reduce the need for expensive upgrades to their distribution SCADA systems. The DSP should seek to reduce the need for expensive upgrades to communication systems like using dedicated fiber optic networks.

Over time the DSP process should inform rate design so that future grid constraints can be avoided by the timely co-location of resources, particularly as electric vehicle charging becomes more common. The combination of a transparent DSP and advanced rate design should result in the adoption of more energy storage systems and the reduction in reliance on natural gas generation to assure reliable electric service.

c) How should distribution system plans be integrated with other planning activities, such as resource planning, interconnection, transmission, or others?

Utility DSPs should inform utility IRPs and regional transmission planning. DSPs by design will require bottoms-up planning where needs are identified on a very granular basis by time and location. IRPs and transmission plans have historically used more top-down planning processes that are informed by analyses of broader economic factors. The combination of bottoms-up and top-down processes should result in better utilization of power supplies, the transmission system and distribution assets.

Duke Energy in a recent filing to the North Carolina Utilities Commission[1] observed that integrated systems and operations planning is “a multi-faceted effort due to the necessary coordination between multiple planning disciplines.” They recommend that there be coordinated data analysis and hand-offs between distribution, transmission and generation planning disciplines.

Duke intends to develop hourly load forecast for each of the distribution circuits in its service areas over a 10-year planning horizon to capture the potential deferred distribution, transmission and generation capacity benefits for DERs. They intend to coordinate modeling across distribution, transmission and generation with the objective of determining achievable

[1] Duke Energy Carolinas, LLC and Duke Energy Progres, LLC’s Response to the Commission’s July 23, 2019 *Order Scheduling Technical Conference and Requiring Response to Commission’s Questions,* August 21, 2019

cumulative value for DERs, particularly energy storage systems. Duke's process is a good model for how a comprehensive process can result in more efficient planning and transparency.

The hosting capacity analysis should help in streamlining each utility's interconnection process for resources that are installed either behind-the-meter or on the distribution system. The hosting capacity analysis should look at the entire distribution system up to transmission voltage to enable a more transparent interconnection process.

d) What are reasonable options for stakeholder participation in the planning process: direct engagement in the development of plans, the review of draft and final plans, other?

Stakeholders should be fully engaged in the development of the templates that will be used by the utilities in the preparation of the Plans. Stakeholders should also be involved in the development of the screening criteria that will be used to identify and prioritize the development of non-wire solutions for grid needs.

As part of the DSP process utilities should be required to organize community workshops that provide opportunities for stakeholders to ask questions and gain a better understanding of the proposed Plans.

The Commission should engage an independent engineer that will assist in the execution of the DSP process used by each utility in preparing its Plan. The independent engineer should prepare background information that helps stakeholders participate in the review process. An opportunity for formal comments on draft plans should also be adopted.

e) How often should a utility distribution plan be submitted for Commission review?

The distribution plan should be submitted annually. It should include a ten-year planning horizon which forecasts in disaggregated load by distribution circuit as well as DER uptake by circuit. It should include a six-year grid needs assessment that identifies emerging constraints on the distribution system that could trigger upgrades. It should also include an action plan with a budget for a rolling three-year period which identifies specific distribution system projects including those that could be met by non-wire solutions.

4) Planning Scenarios: a) How should the selection of scenarios used in distribution planning be determined?

Several planning scenarios should be used to inform the grid needs assessment. Important factors include the disaggregated forecast of load growth year-by-year and the forecast of the

autonomous uptake of DERs. Key drivers of load growth include electric vehicle adoption, fuel switching to electricity for building end uses and the adoption of incremental energy efficiency measures. The key drivers of DER uptake will be cost of the technologies and rate design. These factors and others should be combined into high, low and base scenarios.

b) What criteria should be used by utilities to identify relevant planning scenarios?

The identification of relevant planning scenarios should be informed both by objective information about exogenous factors like population and economic growth and changes in the structure of the economy as well as policy choices such as greenhouse gas reduction targets, transportation electrification and incremental achievable energy efficiency.

5) Access to grid and planning data by customers and third parties: a) Discuss categories of data needed by third parties to:

i. Participate in developing system plans.
ii. Critically review proposed plans.

The utilities should provide in their Plans the following data sets.

1) Demand forecast by circuit and transformer bank
2) DER growth forecast by circuit and transformer bank for PV, battery storage and energy efficiency. At a later date EV charging can be added.
3) A grid needs assessment that includes the name of the facility, facility type (e.g. substation, line), primary driver (e.g. demand growth, age of infrastructure), distribution service needed (e.g. capacity, voltage support, reliability), upgrade date, equipment rating (e.g. MW, amps, Vpu), deficiency by year
4) Planned investments including name of substation, bank/feeder, project description, equipment included, cost estimate, in-service date, distribution service needed, magnitude of deficiency, screening of DER solution
5) Candidate deferral projects including name of substation, bank/feeder, in-service date, distribution service needed, months of need, duration of need, number of need events/year, magnitude of need, cost estimate for conventional solution

iii. Prepare commercial projects in response to plans.

The utility should prepare an RFP with sufficient detail to encourage response bids. Information in the bid package may include distribution system site plans, detailed distribution equipment loading data, aggregated customer billing information, and pro forma contract.

b) Identify any categories of data that may be unsuitable for access, e.g. for reasons of security, trade secret, customer privacy, or burdensomeness.

It may be appropriate to provide some data under confidentiality agreements for reasons of security and privacy. Presentation of data should be standardized to avoid burdensomeness. Trade secrets would need to be evaluated on a case-by-case basis with the burden of proof on the utility to demonstrate that a trade secret is involved.

c) How should and in what format should the results of a hosting capacity analysis or native loading analysis be made available by utilities? Please indicate which formats are currently available and which are not currently available.

Data on hosting should be made available in machine readable format for downloading. In addition distribution maps with colored highlighting of capacity available should be available via the internet.

d) How should the commission evaluate utility investments that enable more transparent interconnection data to be made available? What are the costs and benefits that the Commission should consider?

Utility investments in transparent interconnection data have the ability to improve the efficiency of the entire siting process, with great potential to reduce costs both for developers and for the utilities. There is an additional potential of such an investment enabling more solar and community solar projects in Oregon, in alignment with customer preferences and Oregon's greenhouse gas reduction goals. Increased data transparency can allow developers to more accurately chose the best sites the first time. With a more efficient siting process, not only can developers potentially reduce interconnection costs but utilities can also reduce costs by avoiding staff resources spent on projects in undesirable locations. In addition, the Commission should consider investments that are user-friendly. Color coded maps that other states have implemented are more accessible for community groups looking to plan community solar projects. The Commission could compare the costs incurred by Oregon utilities with the costs incurred by utilities in other states.

6) Are there other issues or topics not covered here that are relevant to discuss in distribution system planning? If so, what are they and why are they relevant?

Actions to improve social equity should also be included in the Plans. The Plans should develop criteria for identifying disadvantaged communities and include actions intended to address the needs of these communities.

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The Commission should be aware that there is a capital bias in favor of conventional utility investments for improvements/modernization of the electric distribution system. The Commission should consider providing performance incentives if the utility avoids more expensive capital investment by contracting with DER providers for grid services.

The Plans should include a section that evaluates the evolution of energy storage technologies. An integrated bottoms-up analysis would be valuable of how the multiple uses of energy storage can be optimized in a region with abundant but varying amount hydroelectric generation. To reduce greenhouse gas emissions it is important not to lose opportunities to develop cost-effective energy storage projects as an alternative to new natural gas generation.

Respectfully,

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