Portland General Electric Company
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October 29, 2020

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
P.O. Box 1088
Salem, OR 97308-1088

Re: PGE Reply to OPUC Staff UM 2005 Draft Recommendations

Dear Filing Center:

Portland General Electric Company (PGE or the Company) welcomes the opportunity to participate in the Public Utility Commission of Oregon's (OPUC's) Docket UM 2005,[1] which seeks to develop a distribution system planning (DSP) process that allows utilities to optimize the efficiency of their distribution system and maximize customer value. PGE submits these comments in response to OPUC Staff's (Staff) DSP Plan Guidelines (DSP Plan) issued on October 1, 2020, which provide guidance on how best to achieve the goals of UM 2005. [2] PGE appreciates the opportunity to provide comments regarding Staff's draft DSP Plan, and thanks Staff for its efforts to engage with stakeholders to balance the need for transparency, community engagement, and the development of a DSP in Oregon.

Per the introduction of the DSP Plan Guidelines, "Staff believes a new regulatory structure for DSP will enable utilities to better identify system needs and evaluate the evolving range of opportunities that can meet those needs. Staff wants to advance least-cost investments to modernize the grid as a foundation for optimization of the distribution system, in order to foster higher levels of customer access and interaction, and integration of variable resources."[3] PGE supports this vision and agrees that many of the draft recommendations proposed by Staff will advance the purpose and goals of UM 2005.

Though there are areas still to be defined in UM 2005, which is anticipated to evolve through 2029, PGE supports the evolution of a regulatory structure that addresses how utilities recover costs and may earn on investments such as distributed energy resource (DER) investments,

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[1] Public Utility Commission of Oregon, *UM 2005 Docket* (available at https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=21850).
[2] "OPUC UM 2005 Distribution System Planning (DSP) Introduction to DSP Plan Guidelines, Draft, October 1, 2020," accessed October 26, 2020, https://edocs.puc.state.or.us/efdocs/HAH/um2005hah16521.pdf.
[3] "OPUC UM 2005 Distribution System Planning (DSP) Introduction to DSP Plan Guidelines, Draft, October 1, 2020" at page 2, accessed October 26, 2020, https://edocs.puc.state.or.us/efdocs/HAH/um2005hah16521.pdf.

which have the potential to demonstrate additional customer benefits and further support Oregon's decarbonization goals.

PGE is grateful to Staff for acknowledging the interrelations between UM 2005 and other existing regulatory reports. PGE supports the development of a holistic report such as the DSP that incorporates information related to the distribution system and DERs. PGE supports Staff's proposal to suspend certain reports. Further, to ensure that there is not duplicative reporting, PGE encourages permanently removing the requirement of such reports if a DSP Plan is required.

Additionally, PGE supports the draft recommendation goal of maximizing customer value "by ensuring that the utilities' approach to managing and operating the distribution system is evolving in a least-cost, least-risk manner."[4] PGE anticipates further discussion on what constitutes least-cost, least-risk within the structure of a DSP Plan; specifically, on how this relates to the OPUC's vision and intention to enable community and customer investment.

PGE is generally supportive of Staff's draft recommendations for the initial DSP Plan and offers additional considerations below for further refinements of the DSP Plan Guidelines. As Staff considers stakeholder feedback, PGE requests flexibility for the initial DSP Plan and requirements, consideration of timing of the initial DSP, alignment between DSP and IRP, consideration of a tailored engagement plan with a project screening criteria process, and finally consideration of cost recovery.

PGE looks forward to continuing to discuss these issues with the OPUC Commission (Commission), Staff, and stakeholders. Should you have any questions regarding these comments, please contact Angela Long at angela.long@pgn.com.

Please direct all formal correspondence and requests to the following email address pge.opuc.filings@pgn.com.

Sincerely,

/s/ Jay Tinker
Jay Tinker
Director, Rates and Regulatory Affairs

JT/np

[4] The concept of least cost planning originated in Oregon in 1989 through Commission Order 89-507 Docket UM 180, where the Commission directed all energy utilities in Oregon to undertake least-cost planning, which the Commission defined as: "[l]east-cost planning differs from traditional planning in three major respects. It requires integration of supply and demand side options. It requires consideration of other than internal costs to the utility in determining what is least-cost. And it involves the Commission, the customers, and the public prior to the making of resource decisions rather than after the fact. …Least-cost planning as mandated by this order will allow the public as well as the Commission to participate in the planning process at its earliest stages." PGE shares in this ground-breaking achievement and commends Staff for continuing this practice through distribution system planning. "OPUC UM 2005 Distribution System Planning (DSP) Introduction to DSP Plan Guidelines, Draft, October 1, 2020" at page 2, accessed October 26, 2020, https://edocs.puc.state.or.us/efdocs/HAH/um2005hah16521.pdf.

PGE's Reply Comments on Staff's Draft Recommendations – Appendix 1

Process and Timing

PGE supports submitting a DSP biennially; however, some of Staff's recommendations may be challenging to achieve by October 15, 2021. For example, utilities will need time to vet and develop new datasets, models, tools, and to acquire new skills and resources needed for developing such a plan. If utilities need to accelerate these efforts to meet the initial submittal date, this may unnecessarily increase the cost of developing the initial DSP Plan.

In terms of timing, PGE is cautious about proceeding without final guidelines, which are not scheduled to be published until December of 2020. PGE is concerned that the timeline for the initial DSP Plan (i.e., approximately ten months) may constrict a thoughtful community engagement process. To meet the guidelines recommended for the initial DSP Plan by the October 15, 2021 and incorporate a thoughtful stakeholder/community engagement process, ideally, utilities will need to have any proposed pilot projects, roadmaps and/or community engagement plans ready for stakeholder review by the end of 2020.

Process and Timing Recommendations

PGE is concerned that the scope of activity and requested deliverables for the initial DSP Plan may be challenging to complete by October 15, 2021 and could potentially limit important stakeholder feedback. PGE recommends the following for Staff/Commission consideration:

- Not require "acceptance" or "acknowledgment" of the initial DSP as Staff's draft recommendations will entail an extensive amount of resources and effort that may not be feasible within the short timeframe (i.e., by October 15, 2021).
- If "acceptance" or "acknowledgement" is necessary, require the submittal of a plan biennially based on the date of "acceptance" or "acknowledgment" of a utility's DSP Plan, rather than biennially from the date of submission (e.g., October 15, 2021).
- Align the timing of a DSP with IRP filings to ensure that stakeholder feedback and/or any commission action related to a utility's DSP can align with a utility's IRP process. For example, PGE's next IRP will be submitted in early 2022. The DSP will inform the IRP's approach through DER load forecasting and adoption scenarios. If PGE submits a DSP in October of 2021, the DSP may publish results that may be in a "draft" form as PGE will still be developing its IRP.

Commission Action

If the OPUC Commission requires "acceptance" or "acknowledgement" of a DSP Plan, PGE supports Staff's draft recommendation to "accept" the DSP Plans. PGE has concerns that in order to meet "acceptance" of the initial DSP Plan, it could potentially limit important stakeholder feedback. Staff's draft recommendations could require an extensive amount of resources and effort that may not be feasible within the short timeframe (i.e., by October 15, 2021).

Commission Action Recommendations

PGE recommends the following for Staff/Commission consideration:

- Do not require "acceptance" of the initial DSP Plan as recommended above; rather begin commission action with the second DSP Plan.

Scope

Baseline Data and System Assessment

PGE appreciates Staff's consideration and attention to the matter of overlapping reporting requirements. PGE supports the recommendation to temporarily waive related reporting requirements until after the initial DSP. Past reports (e.g., Smart Grid Report, Annual Net Metering Reports) are in most cases not formal planning documents, and as such do not require the rigor of system planning seen in items like an IRP or the kind of modeling intensity envisioned for DSP.

PGE supports Staff's draft recommendation that the DSP provide "understanding and enable effective decision-making." If Staff's intent is for utilities to provide a "fundamental understanding of the current physical status of the utility distribution systems, recent investment in those systems, and DERs currently integrated into those systems,"[5] then PGE recommends a less data prescriptive approach that also considers cybersecurity and customer data privacy.[6]

If possible, PGE recommends reducing the scope of this data gathering effort to projects relating to or developed by its distribution system planning team. Also, PGE foresees challenges with categorizing some of the data recommended by Staff as it may not exist in current databases and/or has not previously been tracked at the level Staff is recommending. PGE suggests a less prescriptive approach to baseline data and system assessment. PGE's suggested approach would capture three broad data categories related to the distribution system (i.e., Sustain, Grow, and Transform). Sustaining the system would refer to reliability, related compliance activity, and enhanced system operability data. Growing the system would refer to additional capacity of system flexibility, related compliance activity, or response to customer requests (e.g., large load additions). Transforming the system refers to projects related to building and/or operating a smarter grid.

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[5] "OPUC UM 2005 Distribution System Planning (DSP) Introduction to DSP Plan Guidelines, Draft, October 1, 2020" at Appendix 1, page 3, accessed October 26, 2020, https://edocs.puc.state.or.us/efdocs/HAH/um2005hah16521.pdf.

[6] As the grid evolves to accommodate a growing penetration of distributed energy resources, the threat surface for possible cyber-attacks widens across a growing interface made up of connected devices, data flow, and information management needs. Standards and protocols to handle this issue are still in the very early stages of development and have not been deployed at scale to test their usefulness in preventing or minimizing threats to the integrity of the electrical grid. PGE understands Staff and stakeholders' desire for more and better information relating to areas of DSP that impact cost or process efficiency to getting new resources interconnected to the grid. However, it is critical that any efforts to increase useful information flow also adhere to the strict privacy protections and standard of care that are core to PGE's mission as a critical service provider to the region.

Baseline Data and System Assessment Recommendations

PGE recommends that where some areas of additional reporting requirements do not add substantive value to the types of discussions ongoing in UM 2005 they should not be required. PGE recommends the following for Staff/Commission consideration:

- As stated above, broaden data requirements to incorporate three broad data categories related to the distribution system (i.e., Sustain, Grow, and Transform).
- Final guidance for the DSP Plan should specify a date range for all datasets (e.g., *items k, m, and o* of Staff's recommendations) to ensure consistency between datasets.
- Limit reporting on spending to defined DSP investments for item *(j.) Historical distribution spending in the past five years, in each category*. PGE recommends limiting reporting to the types of spending most closely aligned with the topics addressed through UM 2005 workshops, such as capacity expansion, grid modernization, etc. These items will provide insights related to how PGE is planning for load growth and DER integration, which the Commission will need to have in order to understand how utilities are planning for current and future grid needs. Focusing on higher value items and their associated datasets will grant better focus on effectual items and thereby provide better clarity for next steps.
- Clarification on item *(f.)*, which states "A summary of the measurement of the performance of the distribution system (feeder-level and time interval), resulting from equipment with monitoring and control capabilities, and AMI meters, including information on percentage of system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual)."[7] It is unclear to PGE whether Staff is suggesting a summary of how granular the measurements are on the distribution system (e.g., what percentage of feeders have SCADA, and what time interval measurements are available) or whether Staff is asking for the actual measurements themselves. PGE requests clarification and recommends that the guidance be limited to the former.
- Remove requirement item (*n.) A map, in electronic format, identifying locations of net metering, small generator, and any other distributed generation resources and distributed energy storage systems*. PGE cannot provide information at this level of granularity as it may violate customer privacy. PGE recommends that customer data remain confidential between the customer and the utility, as governed by existing law and privacy policies. PGE recommends rewriting the requirement to provide distributed generation information at an aggregated level, such as feeder-level or circuit-level.
- PGE recommends that the Commission undertake a process to work with utilities and industry experts to better understand cybersecurity considerations for DERs and how these relate to DSP. This work should inform the long-term evolution of DSP in regard to data transparency and security and should balance stakeholders' needs with the growing

[7] "OPUC UM 2005 Distribution System Planning (DSP) Introduction to DSP Plan Guidelines, Draft, October 1, 2020" at Appendix 1, page 4, accessed October 26, 2020, https://edocs.puc.state.or.us/efdocs/HAH/um2005hah16521.pdf.

need of utilities to maintain a safe and reliable supply of power with evolving protection needs.

Load, Distributed Energy Resource, and EV Forecasting

PGE supports Staff's draft recommendation that utilities provide details regarding how DERs affect load forecasting, and how system-level forecasts are allocated to inform locational planning. This is a critical need as most traditional distribution system planning has looked at aggregate load growth and has not accounted for the capabilities of DERs.

PGE appreciates Staff's defining DERs.[8] PGE plans to submit results of its DER Potential and Flex Load study within the DSP, including aspects of locational forecasting. PGE recently contracted with a third-party consultant, Cadeo Group with subcontractors The Brattle Group and Lighthouse Energy Consulting, to conduct a DER Potential and Flex Load Study in preparation for its next IRP. Due to the timing of this effort, PGE may not have the data requested by Staff in its draft recommendation available in time for the initial DSP.

Load, Distributed Energy Resource, and EV Forecasting Recommendations

PGE raises for conversation with Staff and stakeholders the proper balance and cadence of information flow related to DERs and their impact on load growth between the DSP and the IRP. Given the schedule in the draft guidelines, utilities will file the initial DSP in October 2021, but PGE's IRP will not likely be filed until early 2022. PGE recommends the following for Staff/Commission consideration:

- Clarification that given the timeframe to complete the initial DSP Plan, utilities not only have discretion around the granularity of the locational aspect of the DER adoption forecast, but also on the vintage of data used.
    - In the event that PGE's DER Potential and Flex Load study results are not completed or are not available at the time of submittal for the initial DSP Plan, PGE requests flexibility on this recommendation for the initial DSP Plan.
- Align timing of DSP to be filed after the IRP. This will allow PGE to fully vet new analysis that will be key inputs into the IRP through the IRP stakeholder process and Commission IRP acknowledgement process.
- Clarification within the final DSP guidelines from Staff and the Commission as to how PGE should consider this timing issue given expected stakeholder interest in treatment of DERs in both plans.
- Clarification on whether Staff's definition of DERs includes qualifying facilities.

Hosting Capacity Analysis

PGE supports Staff's goal of transparency and visibility into PGE's system. Hosting Capacity Analysis (HCA) may allow prospective interconnection customers to make more informed business decisions prior to committing resources to an interconnection application. However, it is

[8] For the purposes of these guidelines "distributed energy resource" includes distributed generation resources, distributed energy storage, demand response, energy efficiency, and electric vehicles that are connected to the electric distribution power grid. "OPUC UM 2005 Distribution System Planning (DSP) Introduction to DSP Plan Guidelines, Draft, October 1, 2020," page 3, accessed October 26, 2020, https://edocs.puc.state.or.us/efdocs/HAH/um2005hah16521.pdf

also important to recognize that although valuable in informing customer decisions, PGE does not support using HCA to replace any part of the interconnection process.

HCA may be utilized to inform preliminary system upgrades/requirements pertaining to early stages (e.g., scoping call, feasibility study) of the interconnection process. However, improvements in hosting capacity capabilities may facilitate activities within the interconnection process but may not replace them or provide total visibility into PGE's system. It is quite likely that additional local studies will need to be performed to determine the viability of adding DERs.

PGE is particularly interested in hearing from the OPUC, partners, and stakeholders regarding the necessary functionality of an HCA tool and how it would be valuable to communities and customers. PGE suggests a dialogue around development of HCA; specifically, who the beneficiary of the analysis would be, and who would bear the costs of the analysis and any associated tools.

Further, PGE appreciates the OPUC's recognition of PGE's constrained feeder map as a starting point for communicating to stakeholders. PGE will continue to produce this version of hosting capacity and, with input from stakeholders, will improve upon its usefulness to DER developers, communities and businesses.

Hosting Capacity Recommendations

PGE believes that HCA may assist in guiding DER investments to areas of the grid where the costs of interconnection are likely to be the lowest. PGE recommends the following for Staff/Commission consideration:

- Consolidate proposed HCA roadmaps (*items b and c*) into a singular roadmap aimed at meeting needs as recommended by Staff.
- Remove the following requirement *(d.) Types of analyses and parameters HCA roadmaps should consider*. PGE intends to leverage the lessons learned by other utilities in their HCA analyses, as well as customer and stakeholder feedback to inform their roadmap. Evaluating these "analyses and parameters" may require significant effort with questionable value or contributions to advancing HCA.

Community Engagement Plan

With the energy industry evolving rapidly, and as PGE seeks to deliver a clean, equitable energy future, the community engagement requirements detailed in the DSP Plan support PGE's efforts to become a more accessible and inclusive utility partner. While PGE supports the guiding principles used to inform the development of the initial DSP Plan, the requirement of two stakeholder workshops under a constrictive timeline does not set the stage for robust engagement. During the 2019 IRP, PGE held a community workshop in support of one of the IRP's goals to engage community and equity groups. From this workshop, PGE learned that further work is required to develop relationships in the community and identify the right partnerships with community-based organizations (CBOs) before expecting meaningful feedback on a topic like PGE's IRP. Because of this, PGE believes it will be necessary to have more than two workshops for the initial DSP Plan.

If possible, PGE intends to utilize learnings from the above example and apply them to the development of the DSP Plan. PGE seeks to foster a diversity of voices from a variety of CBOs and other environmental justice organizations, such as Native American Tribes, seniors, and people with disabilities, that have not been engaged in the UM 2005 process thus far. PGE encourages the OPUC to reach out to these groups as part of its community engagement activities. As shared in OPUC's webinar on *Best Practices for Community Engagement,*[9] presented by Community Energy Project (CEP) and Verde, building trust takes time. There also needs to be a reason for engagement that ties to community needs as a precursor to meaningful engagement on a specific topic area. Without the necessary time to build trust and develop an awareness and understanding of energy decisions and how it impacts community members' lives, these public processes may not support UM 2005's guiding principle for inclusion that seeks to ensure meaningful diversity of voice and perspectives. To ensure that a DSP Plan establishes a public process that engages community members, particularly those from underserved communities, in a more robust way moving forward, more time should be granted for utilities, the OPUC, partners, communities, and stakeholders to have discussions about the structure, frequency, and scope of these workshops.

In addition, while PGE supports Staff's multipronged engagement approach with two proposed pilot projects in the *Grids Needs Assessment* and *Solution Identification* sections of the DSP Plan Guidelines. PGE does suggest that more time and flexibility be given to co-developing the scope of these pilots with partners and stakeholders to explore different engagement mechanisms that utilities can leverage to pursue these pilot projects, such as through contracting with a CBO or developing an advisory committee channel.

With respect to guidance for reasonable levels of spending to meet requirements for community engagement and planning, PGE supports the OPUC's efforts to break down barriers to inclusive participation in energy public processes, including a lack of funding to support historically excluded stakeholders.

Lastly, PGE looks forward to transparent discussions with partners and stakeholders that are grounded in the Staff's approaches to engagement. Given the reality of both in-flight and planned projects, PGE envisions different stages of engagement that are on a spectrum and occurring in parallel and informed throughout a given planning horizon. For example, engagement on long-term solution identification would be further to the right of the spectrum ("involve and collaborate") relative to in-flight projects that were planned prior to this proceeding ("inform and consult"). PGE supports engaging with communities early in the solution identification stage and will co-develop further criteria about the type and size of distribution investments that are shared through a tailored community engagement plan process. PGE will also work with partners and stakeholders to identify what types of projects they are seeking to be engaged on, and what is most valuable to them. Additionally, PGE recognizes that "community" is not a monolith and therefore PGE requests that partners and stakeholders with location-based knowledge aid in identifying with whom PGE should engage.

[9] "Webinar #6: Best Practices for Community Engagement," accessed October 26, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Webinar6-Agenda.pdf.

Community Engagement Plan Recommendations

PGE is excited to engage with its community partners and stakeholders. It is important to acknowledge that, for the initial DSP Plan, many utility investments have already been planned; therefore, PGE envisions different stages of engagement. PGE recommends the following for Staff/Commission consideration:

- Additional time be granted so that utilities, the OPUC, partners and stakeholders can have further discussions about the structure, frequency, and scope of the two workshops to ensure that they result in advancing the DSP Plan's guiding principle of inclusion.
- Additional time and flexibility should be given to co-developing the scope of Staff's two proposed pilot projects. This will allow for utilities to engage with partners, stakeholders and CBOs. This will ensure that utilities explore different engagement mechanisms that can be leveraged to pursue the two required pilot projects.
- Clarify what the expectations will be for stakeholder participation in the DSP Plan; specifically, what types of engagement would allow stakeholders to recover costs associated with their participation in a DSP Plan.

Grid Needs Identification

PGE appreciates Staff's focus on blending the traditional utility practices to assess grid needs with the needs of community, particularly social and economic needs. As shared in the *Best Practices for Community Engagement* presentation by CEP and Verde, identifying community need is the first step for community-led Distribution System Planning.

PGE believes that in order to meet the aggressive decarbonization goals adopted by PGE's municipal partners and communities, an integrated, modernized grid is essential. When considering grid needs it is important to center an identification process on reliability, safety, security, quality, capability and flexibility. Such a platform will also provide for better alignment of utility system investments with new customer values that will be brought on by greater adoption of DERs while not sacrificing reliability, safety, security and quality.

During the workshop process, PGE appreciated Staff's invitation to share its knowledge with partners and stakeholders about current distribution planning processes, while also covering examples of grid modernization projects (i.e., distribution automation). PGE also shared how it currently forecasts DERs within the IRP and Transportation Electrification (TE) Plan, including assessments of locational adoption of electric vehicles (EVs).

Through its presentations of current distribution planning processes, PGE met with partners and stakeholders to translate technical information and develop a common understanding of community planning and system needs assessment. For this reason, PGE asks for the opportunity to work with Staff, partners and stakeholders on establishing tools and processes that work for everyone as opposed to racing to a grid needs identification process through the "finish line," which would likely frustrate parties.

PGE agrees with Staff's focus that working together is needed to ensure that the transition to a clean energy future is equitable. As Oregon moves toward a decarbonized grid of the future,

PGE lists below areas of engagement that have the potential to complement and strengthen existing DSP Plan efforts and potentially assist in addressing historical inequities:

- Community Green Tariff
- Resiliency Initiatives and Microgrid Site Criteria Selection
- Testbed Community Outreach Efforts
- Municipal partnerships geared toward climate action and workforce development

Grid Needs Identification Recommendations

PGE appreciates the opportunity to develop meaningful engagement pathways for its partners and stakeholders. PGE recommends the following for Staff/Commission consideration:

- Clarification on what expectations Staff has surrounding pilots proposed as Grid Needs Assessment projects; specifically, types of projects, costs, scope, and timing.
- Clarification on what level of engagement will be sufficient to develop the shared understanding of community needs in relation to Grid Needs Identification.
- Allow the initial DSP Plan to report on the status of community engagement and the grid needs assessment, and not have an expectation that work necessarily be completed.

Solution Identification

PGE has a robust history of planning and executing traditional solutions to build and maintain a reliable and safe distribution grid. As customers are beginning to adopt more DERs, the nature of planning must also change. PGE recognizes the need for a paradigm shift from one-way power flow to a system marked more by decentralized, two-way power flow and dynamic energy consumption patterns. PGE's grid modernization investments and flexible load initiatives are bringing more visibility into real-time distribution system operations and the ability of DERs to provide an array of grid services. As DER penetration continues to grow, so does the possibility of leveraging their collective use for a wider suite of grid services.

To ensure that utility and customer energy solutions fit together, PGE is currently evaluating its existing tools to confirm that it has the capability to assess new and complex solutions to changing grid needs. By doing so, PGE can maximize the value of a modernized grid to the benefit of all customers. PGE's goal is to continue to act as a trusted energy partner for its customers and communities while maintaining the safety and reliability of the distribution system and keeping prices affordable in the face of growing intermittent renewable power generation and EV loads.

PGE supports Staff's draft recommendation for utilities to submit two proposals for non-wires alternative (NWA) pilot projects. PGE looks forward to having further dialogue with Staff, the Commission, partners and stakeholders, and will draw upon the various pilot activities referenced in this section to inform the DSP Plan. PGE also feels that this process will be greatly aided by a parallel discussion about evolving the utility business model, and how regulatory earnings pilots will also feed into the efficacy of such NWA pilots. This has been a longstanding area of interest for stakeholders and utilities. Further, PGE welcomes the opportunity to investigate these evolutions in tandem to address the challenges and opportunities presented by integrated distribution system planning (iDSP) in Oregon.

The DSP Plan will advance PGE's existing DER work as it relates to identifying new solutions to grid needs, including exploration of new valuation methods, developing assessments of NWAs, and flexible load pilots. These efforts provide valuable market experience pertaining to customer needs, technology costs, and performance features of flexible loads. Provided below are some examples of PGE's existing DER related initiatives that will be key to a DSP Plan.

Smart Grid Test Bed. Within the Smart Grid Test Bed, PGE has endeavored to accelerate adoption of DERs and increase participation among certain Flexible Load programs. Part of the learnings from this effort relate to program planning, marketing, and customer motivations, but there are also lessons for distribution system planning to the extent these resources can be modeled in a local grid context.

Locational-Net Value. Recently, PGE engaged with a third-party consultant, Kevala, Inc., to model DER adoption and impacts in the three testbed substations using a site-level, time-series approach to aggregating DERs. This study conducted power flow analyses across a number of load growth scenarios and explored the relative contributions of DERs to minimizing distribution system violations (e.g., related to voltage, loading, or fault current) associated with unmanaged load growth. PGE is still in the process of completing this analysis and verifying outcomes within our distribution planning tool, CYME.

Improving planning and assessment tools to understand the full costs and benefits of using DERs for different grid use cases allows for better solution identification. Importantly, PGE's Locational-Net Value study also looks at the cross-section of DER load and resource profiles, locational nodal wholesale energy pricing, and distribution capacity deferral value. This is an important step forward in understanding how different DERs can contribute to overall system value.

Non-Wires Alternatives Screening. In order to advance planning capabilities in solution identification, PGE has engaged with a third-party consultant, OpusOne Solutions, to model DER's ability to defer capital investments at three substations where constraints are expected. PGE is in the early stages of this work and looks forward to discussing the results with Staff, partners and stakeholders as part of future workshops. PGE is developing preliminary screening criteria to select the first three substations for analysis. Though this screening is expected to evolve with input from Staff, partners and stakeholders, PGE will use this as a starting point for conversations with Staff, partners and stakeholders for how PGE would approach NWA solutions from a grid needs perspective. PGE expects to share these criteria with stakeholders, and further identify how to best incorporate community needs and socio-economic criteria as an outcome to the pilot community grid needs assessment referenced above.

Energy Storage Activities. PGE is developing a range of projects to deploy battery storage onto the system and gather valuable learnings about the potential use cases, costs, and adoption challenges of these resources. Many of the learnings from these activities will have direct relevance to furthering DSP at PGE, including assessing their ability to provide distribution capacity deferral and ancillary grid services.

There are a number of ongoing activities related to customer-grid interactions and PGE will highlight two projects in this space.[10] PGE has completed construction and energization of the Beaverton Public Safety Center microgrid, a 250 kW, 4-hr battery coupled with solar, diesel backup generation, and advanced controls to safely isolate from the grid during outages and continue to provide reliable power supply. This is a great example of combining resiliency and grid service provision for a critical facility that serves the broader public. PGE looks forward to more opportunities to jointly develop such meaningful projects for our customers.

Additionally, on June 30, 2020 the OPUC granted regulatory approval for Schedule 14 and allowed PGE to initiate our Smart Battery pilot, which will integrate up to 525 customer-owned residential storage units as a dispatchable resource providing grid services. During grid outages, the energy storage system will provide back-up power to participating residences. In exchange for allowing PGE to operate the battery for grid services, a customer will receive $20 or $40 per month.

Solution Identification Recommendations

PGE knows customers want a more decarbonized energy system and a voice in the energy decisions that impacts their lives. PGE strongly feels that a shared development of solutions, facilitated by listening to the partners, communities and to our customers, will be key to making the right investments that can provide the most shared value. PGE recommends the following for Staff/Commission consideration:

- Allowance for utilities to pursue non-cost-effective pilot projects that may provide some benefits that achieve the DSP Plan Guidelines goals and vision. Currently, NWA projects may not be identified as the least-cost, least-risk resource because current cost-benefit analysis may not value all the anticipated benefits that DERs may provide. Utilization of a shared investment of the electric grid may provide the most value to customers; however, cost-effectiveness tests may not fully account for all the benefits of DERs. Accounting for the expected benefits of DERs entails developing creative solutions that account for customers' needs that may go beyond reliable, safe, and affordable energy. By doing so utilities and the OPUC will be challenged to take stock of how customer-sited energy resources may be able to contribute new services that advance the grid and Oregon's goals of decarbonization and equity.
- Consideration of how DER solution identification is screened for and evaluated. For example, should DERs that provide grid flexibility be evaluated differently due to their capabilities? This is an important question, as "flexible loads" may not always be the least-cost, least-risk resource.
- Tailored community engagement. PGE stresses that the Commission should be thoughtful about when and where stakeholder input is required. There already are a variety of distribution planning activities that are in place to comply with regulatory and safety needs, which may be less productive areas of engagement. However, projects associated with load growth, DER adoption, and non-wires alternatives may be of more immediate concern for collaboration. Having clear guidelines about appropriate

[10] "PGE UM 1856 2020 Annual Energy Storage Update" August 27, 2020, accessed October 27, 2020, https://edocs.puc.state.or.us/efdocs/HAD/um1856had151753.pdf.

engagement will help make the most of the earnest efforts and interest of stakeholders to advance this process in Oregon.

Near-Term Action Plan and Long-Term Plan

PGE is supportive of a near-term action plan that provides visibility into a utility's distribution planning process. PGE is interested in understanding how any near-term investment actions and their associated projected distribution spending would be recovered. Currently, there is no formal cost recovery mechanism for distribution investments that may not be least-cost, least-risk, but provide other important anticipated benefits such as equity for underserved communities or greenhouse gas reductions.

PGE also supports a long-term plan that provides a roadmap to how utilities can support Oregon's decarbonization goals as well as the OPUC's goals. Throughout this process, stakeholders have asked how distribution system investments can address decarbonization goals, and PGE agrees this is an important, though challenging, problem to tackle. A long-term plan should clearly outline how consideration of such goals, among other priorities, should be valued in the DSP and IRP contexts. In the short-term this will be an evolving consideration as investments at the distribution-level may not always result in a least-cost, least-risk resource. Over time, PGE expects to develop more robust planning and valuation of DERs in terms of locational benefits to the system and impacts on risk assessments, which can then feed into and complement the IRP's focus on meeting customer load and reliability targets in aggregate. PGE is interested in understanding how any long-term investment actions would inform the IRP process and what Commission and stakeholder expectations will be between a DSP and an IRP.

Near-Term Action Plan and Long-Term Plan Recommendation

PGE recommends the following for Staff/Commission consideration:

- Consider how a potential long-term DSP action plan may inform the IRP and vice versa.
- Through the evolution of the DSP, the Commission consider how "acknowledgment" of a DSP may influence portfolio selections in the IRP. For example, if a DSP considers different cost and benefits than an IRP, how will that inform the development of an IRP preferred portfolio that aims to achieve the least-cost, least risk portfolio.

Evolution of DSP

PGE appreciates Staff's thoughtfulness in evolving the DSP over time. Below are three areas that PGE sees DSP evolving over time.

Data Privacy and Security. As the grid evolves to accommodate a growing penetration of DERs, the threat surface for possible cyber-attacks widens across a growing interface made up of connected devices, data flow, and information management needs.[11] Standards and protocols to handle this issue are still in the very early stages of development and have not been deployed at scale to test their usefulness in preventing or minimizing threats to the integrity of the electrical grid. PGE understands Staff's and stakeholders' desire for more and better information relating to areas of DSP that impact cost or process efficiency to getting new resources interconnected to

[11] "NCCoE to Address Cybersecurity Challenges of Distributed Energy Resources," accessed October 26, 2020, https://www.nccoe.nist.gov/news/nccoe-address-cybersecurity-challenges-distributed-energy-resources.

the grid. However, it is critical that any efforts to increase useful information flow also adhere to the strict privacy protections and standard of care that are core to PGE's mission as a critical service provider to the region.

Data Privacy and Security Recommendations

PGE recommends that customer data remain confidential between the customer and the utility, as governed by existing law and privacy policies. PGE also recommends that the Commission undertake a process to work with utilities and industry experts to better understand cybersecurity considerations for DERs and how these relate to DSP. This work should inform the long-term evolution of DSP in-regards to data transparency and security and should balance stakeholders' needs with the growing need of utilities to maintain a safe and reliable supply of power with evolving protection needs.

Cost Recovery. PGE considers this to be an important contributor to the success of a DSP. The approach to compensating CBOs for their time and effort, as well as how utilities recover costs related to DER investments are two considerations that influence the pace of activity. Continued conversations are necessary to clarify the treatment of CBO and utility investments.

Cost Recovery Recommendation

PGE requests that Staff/Commission consider a formal process for discussing this topic. At a minimum, PGE recommends at least one Staff-led stakeholder workshop next year prior to October 15, 2021 that will allow utilities to incorporate feedback into their DSPs.

Regulatory Development. PGE appreciates Staff's consideration of on-going regulatory development. Now, as utilities continue to make investments in grid modernization in order to ensure continued safe and reliable distribution of electricity in the face of changing pressures and market contexts, attention has duly turned to how DERs can contribute in meaningful ways to decarbonization. PGE appreciates and acknowledges the statements made by Staff, partners and stakeholders reflecting a desire for equitable development of DERs and ensuring that participation in the clean energy economy is available and accessible to all customers.

Regulatory Development Recommendation

PGE requests that Staff begin developing a series of topic-focused workshops needed to address specific topics of transformational regulatory development such as consideration of utilizing the National Energy Screening Project (NESP) new cost-effectiveness screening practices for distributed energy resources (DERs).[12]

Conclusion

PGE believes that UM 2005 is critical to achieving the objectives set out in Executive Order (EO) 20-04, established by Governor Brown, which issued new greenhouse gas (GHG) emissions goals for Oregon and directed state agencies to identify and prioritize actions to meet those goals. EO 20-04 also provides specific directives to the Public Utility Commission of Oregon (OPUC) on GHG emissions, impacted communities, and wildfire safety. PGE appreciates Staff's hard work and efforts to align UM 2005 with these goals. PGE would also

[12] "National Energy Screening Project," accessed October 27, 2020, https://www.nationalenergyscreeningproject.org/.

like to thank Staff for taking the time to meet with PGE on several occasions throughout the docket process to discuss varying issues and topics.

PGE kindly requests consideration of PGE's recommendations regarding Staff's draft recommendations. These recommendations are supported throughout the document and summarized in this conclusion for Staff's/Commission consideration.

Process and Timing. PGE requests that the submittal of a DSP Plan be required every two years based on the date of "acceptance" or "acknowledgment" of a utility's plan, rather than two years from the date of submission. PGE also requests that the Staff align the timing of the DSP to be filed after the utilities most recent IRP filings to ensure that stakeholder feedback and/or any commission action related to a utility's DSP can align with the IRP process.

Commission Action. PGE requests that the initial DSP Plan not require an "acceptance" by the Commission.

Baseline Data and System Assessment. With respect to item *(j.) Historical distribution spending in the past five years, in each category*, PGE recommends this be limited to the types of spending most closely aligned with the topics addressed through UM 2005 workshops, such as capacity expansion, grid modernization, etc. These items provide insights related to how PGE plans for load growth and DER integration, which the Commission will need to have in order to understand how utilities are planning for current and future grid needs. PGE suggests removing requirements for preventative maintenance and vegetation management as these items are of *de minimis* value to furthering understanding of DSP. Focusing on higher value items and their associated datasets will grant better focus on effectual items and thereby provide better clarity for next steps. PGE also requests that all data requirements specify the length of data required to ensure consistency between datasets (e.g., one year of data). PGE requests additional flexibility regarding what type of data can be reasonably delivered within the first year and how utilities can leverage first step success to accelerate to a more robust and formal distribution system plan.

Load, Distributed Energy Resource, and EV Forecasting. Align the timing of a DSP with IRP filings to ensure that stakeholder feedback and/or any commission action related to a utility's DSP can align with the IRP process.

Hosting Capacity Analysis. PGE requests the consolidation of the two roadmap proposals (*items b and c*) into a singular roadmap. PGE also requests the removal the following requirement *(d.) Types of analyses and parameters HCA roadmaps should consider*.

Community Engagement. PGE requests that additional time be given to developing a community engagement plan for the proposed pilots.

Grid Needs Identification. PGE requests a tailored community engagement process that will provide visibility into how utilities make investments, but that also allows for a streamlined community engagement approach. PGE recommends starting with NWA screening criteria that would narrow the list of distribution projects to the right type of projects. For instance, a

replacement of a pole due to wind damage may not be a fruitful project for community engagement versus a project aimed at developing a new substation.

Solution Identification. PGE requests that Staff consider allowing utilities to pursue non-cost-effective DSP pilot projects. PGE requests consideration of a process that allows utilities to appropriately value DERs based on their capabilities. PGE also requests a more tailored community engagement or the inclusion of communities and CBOs in the solution identification process. This could be achieved by creating a vetting process for projects that are prioritized through screening criteria process.

Near-Term Action Plan and Long-Term Plan. PGE recommends Staff/Commission consider how a potential long-term action plan may inform the IRP and vice versa in its final requirements or in its regulatory development process.

Evolution of DSP. PGE requests that customer data remain confidential between the customer and the utility, as governed by existing law and privacy policies. PGE requests that Staff/Commission consider a formal process for discussing this topic. PGE requests that staff a begin developing a series of topic-focused workshops needed to address specific topics of transformational regulatory development.

Respectfully Submitted,

/s/ Jay Tinker
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