VIA ELECTRONIC FILING

July 26, 2024

Public Utility Commission of Oregon
201 High Street SE, Suite 100
P.O. Box 1088
Salem, Oregon 97301

Re: Docket UM 2005 – Proposed Distribution System Planning Guideline Revisions

Dear Filing Center:

Idaho Power Company ("Idaho Power"), Portland General Electric Company ("PGE"), and PacifiCorp d/b/a Pacific Power ("PacifiCorp") (collectively, the "Joint Utilities") are grateful for the ongoing opportunity to offer comments in the Public Utility Commission of Oregon's ("OPUC" or "Commission") Docket UM 2005. Specifically, these comments offer additional considerations and recommendations from the Joint Utilities on OPUC Staff's ("Staff") proposed guideline revisions for utility Distribution System Plans ("DSP").

In the public DSP workshop held on July 10, 2024, Staff announced an extended comment opportunity on the proposed DSP guideline revisions, with a closing date of July 26, 2024.[1] During the workshop, Staff characterized the extended comment period as an opportunity for stakeholders to weigh in who had not already had the opportunity or time to do so. Certainly, the Joint Utilities do not offer these comments with disregard for Staff's intent. Rather, the Joint Utilities offer these comments as a final request for additional process to ensure clarity and understanding of the proposed guidelines such that our companies can deliver our next DSPs in a meaningful and complete manner.

Idaho Power, PGE, and PacifiCorp's individual comments, submitted into this docket on May 31, 2024 (and included with these comments as Attachments A, B, and C, respectively) contained significant feedback on the proposed guideline revisions. In some instances, the individual comments offered possible alternative language for clarity, while in other instances the comments did not venture an alternative but, instead, suggested more opportunities to discuss outstanding issues and concerns. By Staff's count, as reported during the July 10th workshop, the

[1] Docket UM 2005, Public Workshop Distribution System Planning Guidelines, July 10, 2024, slide 13.

Joint Utilities offered more than 100 unique points of feedback in the form of questions, suggestions, or other requests for clarity and additional discussion.

While the Joint Utilities greatly appreciate Staff's effort to date in this docket, including the recent public workshop and the extended comment period, we believe there simply has not been enough time to discuss, consider, and ultimately resolve issues present in the proposed guideline revisions. The July 10th workshop offered excellent discussion but also underscored that a single two-hour workshop is not sufficient to work through the items raised by Idaho Power, PGE, and PacifiCorp.

The Joint Utilities fully appreciate the perspectives of other stakeholders in UM 2005, many of whom voiced their support at the July 10th workshop for the guideline revisions as proposed by Staff. However, the Joint Utilities are in a unique position with respect to the DSP, as we are responsible for developing the DSPs. If we do not fully appreciate or understand the guidelines, the Joint Utilities may not be able to fully comply. To be clear, this call for process is in no way a desire to delay. Prior to Staff releasing these guideline revisions on April 29, 2024,[2] this docket was idle for more than a year. The Joint Utilities do not believe that an additional two or three months of process—in the form of additional rounds of proposed guideline revisions, opportunities for comment, and workshops—is an unreasonable request.

More specifically, the Joint Utilities respectfully request additional process such that the Joint Utilities, Staff, and interested stakeholders can:

- Gain additional insight from Staff on the purpose, intent, and execution of guideline elements that will create the "thru-line" between DSPs and later cost recovery filings;
- By extension, clarify legally questionable language in the proposed guideline revisions related to the tie between DSP and future cost recovery proceedings and language that suggests the OPUC may direct utility decisions and actions as highlighted by PacifiCorp's comments and citations on pages 1-3 of Attachment C;
- Have a more in-depth discussion about the degree to which the current proposed guidelines revisions will not produce plans as much as they will produce a managerial view of a utility's distribution system operations and investment;
- Better understand Staff's expectations for connecting the DSP to parallel planning efforts such as Integrated Resource Plans and Wildfire Mitigation Plans; and
- An opportunity to go line-by-line through specific language, and then discuss and refine as necessary to ensure common understanding and alignment of intent.

This will require many hours of thoughtful, purposeful discussion—which would ideally occur through a combination of workshops and written comment. Without such discussion, we risk

[2] Staff's Proposed Distribution System Planning (DSP) Guideline Revisions, April 29, 2024.

concluding the process with language in the guidelines that may not clearly reflect a well-grounded understanding of the intent behind the guidelines and expectations of what utilities will deliver in their plans. Considering the above, the Joint Utilities respectfully request additional process in this case to develop substantive and ultimately useful DSPs based on a shared understanding and interpretation of DSP guidelines.

Respectfully Submitted,

/s/ Alison Williams
Alison Williams
Regulatory Policy & Strategy Leader
Idaho Power

/s/ Riley Peck
Riley Peck
Senior Manager, Regulatory Strategy and Engagement
Portland General Electric

/s/ Matthew D. McVee
Vice President, Regulatory Policy and Operations
PacifiCorp

Cc: OPUC Filing Center

ATTACHMENT A
to
JOINT UTILITIES' COMMENTS

(Idaho Power Company's DSP Comments)

ALISON WILLIAMS
Regulatory Policy & Strategy Leader
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VIA ELECTRONIC FILING

May 31, 2024

Public Utility Commission of Oregon
Filing Center
201 High Street SE, Suite 100
P.O. Box 1088
Salem, Oregon 97301

Re: Docket No. UM 2005
Distribution System Planning ("DSP") Draft Guideline Revisions – Idaho Power Company's Comments

Attention Filing Center:

Idaho Power Company ("Idaho Power" or "Company") appreciates this opportunity to provide comments on Staff's proposed revisions to the Distribution System Planning ("DSP") guidelines, as filed on April 26, 2024, in the Public Utility Commission of Oregon's ("OPUC" or "Commission") Docket UM 2005. Staff has undertaken considerable effort and planning to thoughtfully engage stakeholders on the guideline revisions.

In these comments, Idaho Power begins with a high-level overview of Staff's summary of objectives and how the proposed guideline revisions compare to the original guidelines. Additionally, the Company offers general comment on some of the large challenges it sees with the proposed revisions, specifically the goals of connecting the DSP to other planning exercises and the goal of connecting the DSP to future cost recovery.

Idaho Power also offers more detailed comments on specific sections of the guidelines, with the goal of seeking understanding, increasing clarity, or flagging areas of concern or additional consideration. Finally, Idaho Power suggests that more process—in the form of discussions, workshops, and more rounds of guideline revisions and comments—is warranted in this case given the magnitude of Staff's proposed changes.

RECONCILING THE OBJECTIVES OF THE DSP

In the Executive Summary of the proposed guideline revisions, Staff provides a list of "high priority questions" to which it hopes the new guidelines will deliver answers. However, these questions are the first indication of what appears to be a seismic shift in the currently proposed guidelines compared to the original guidelines. The original guidelines were developed to encourage utilities to think creatively about distribution system planning and to do so without necessarily being tied to least-cost planning.[1] To be sure, there were practical elements within the guidelines to paint a picture of a utility's existing distribution system, such as the baseline data and system assessment—elements that remain in the proposed guideline revisions. But many of the planning components were intentionally designed to get at a particular policy outcome—specifically, non-wires solutions that are perceived as more innovative than traditional solutions.[2]

In contrast, the proposed guideline revisions appear to shift the goal of the DSP from aspirational to practical, particularly with respect to gaining insight into near-term distribution investment that would track directly to costs identified in the utility's next general rate case ("GRC").

The struggle before stakeholders, Staff, and the Commission is determining whether the DSP guidelines can be simultaneously aspirational and practical. Some additions and modifications within the proposed revisions skew aspirational, while others are clearly grounded in creating a detailed accounting of actual near-term distribution system investment.

Idaho Power would argue that it might be possible to develop guidelines that make space for innovation and outside-the-box thinking while also providing a practical planning that tracks to future expenditure. Doing so, however, will require measured adjustment to many parts of the guideline revisions, as well as precise, careful language that all stakeholders can universally understand.

In service of such an outcome, Idaho Power offers high-level thematic comments below, followed by more specific comments and suggestions by section of the guidelines.

Connecting the DSP to Other Planning Exercises

One of Staff's objectives is to push utilities to find efficiencies in planning by connecting the dots among various planning exercises such as the Integrated Resource Plan ("IRP") and the Wildfire Mitigation Plan ("WMP"). This is a laudable objective. However, discrete planning efforts serve different purposes and exist on different timelines. Alignment across these efforts is not feasible without significant change to the fundamentals of key planning efforts. For example, an IRP looks at a utility's generation and transmission system from the top-down and does not directly model the distribution system.

If Staff's expectation is a direct connection between the DSP and the IRP, Idaho Power would ask for additional process in this case so that Staff and other stakeholders can better

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[1] In Order 20-485, the Commission adopted Staff's recommendations for DSP guidelines. Within the corresponding memo and beneath the "Cost Recovery and Regulatory Development" heading, Staff stated: "PUC recognizes the need for ongoing conversations about how DSP activities align or interact with the utilities' existing business models and regulatory approaches. To address the changes that utilities may make in implementing the DSP process, the PUC may explore new regulatory mechanisms that may better align with utilities' efforts to plan and invest in the DSP over the long-term. Staff believes these conversations may be premature at this stage." (Appendix A, p. 8)

[2] *Id.*, p. 4. Solution identification, a component of the original guidelines, was explained in Staff's memo as follows, "…utilities will develop two or more pilot concept proposals in which non-wire solutions will be used in place of traditional utility infrastructure investments."

understand the fundamental limitations of such an expectation. Similarly, incorporating or linking DSPs to WMPs may make sense when discussing certain efforts, like large-scale line rebuilds or significant hardening projects. Smaller projects or wildfire mitigation efforts that aren't related to the distribution system will not logically crossover to the DSP. Idaho Power notes these examples to show that the goal of linking planning exercises is reasonable but may not be achievable to the degree envisioned by Staff. One alternative might be narrative descriptions within respective plans in an effort to connect the dots between an activity in one plan and a shared or related activity in another plan.

Connecting Future DSPs to Future Cost Recovery

Staff's first "high priority" question is: "How is the Company prioritizing and containing spend while making decisions across multiple objectives…?"[3] While this perspective and the desire to gain insight is reasonable, the DSP has not served this purpose in the past. Such a pivot to making the DSP a distribution investment tracking document, combined with a plain text reading of several parts of the proposed guideline revisions, suggests that Staff is positioning the future DSPs as serving an early prudency review function. The Company understands from its conversation with Staff in May 2024 that this is not Staff's intention; further, Staff has noted that prudency reviews have specific implications and language that is not reflected in the proposed revisions. And yet, if Idaho Power were expected to reconcile its distribution-related investment and expenditure in a GRC against items in its most recent DSP, that is a form of prudency review. Such a throughline of tracking dollars from the DSP to a GRC suggests that the DSP is no longer a planning document, but a list of impending projects that will be built and for which the Company will be expected to link to items within its GRC.

Integrated Resource Plans ('IRP") offer an interesting parallel in this regard. The IRP is first and foremost a plan; it gives a clear picture of a utility's need and potential investment in generation and transmission, but it does not assume any specific item will occur in exactly the time or composition listed in the IRP. Additionally, the Commission has other venues—such as the competitive bidding process—to vet and authorize individual procurement and then separate cost recovery filings to determine prudency. For example, the Commission's Order No. 23-004 acknowledging Idaho Power's 2021 IRP, states:

> [IRP] Acknowledgement provides guidance for later ratemaking proceedings, which are the forum for the Commission to make its ultimate decision to approve or disapprove a resource procurement as prudent and subject to recovery in customer rates. Consistency with an acknowledged plan may be used as evidence in support of a favorable ratemaking treatment, but the utility still must demonstrate that its actions remained reasonable, particularly in light of any material changes in the facts, circumstances, and assumptions that supported IRP acknowledgement.[4]

[3] Staff Proposed DSP Revisions, p. 1.
[4] LC 78, Order No. 23-004, p. 3.

The proposed DSP guideline revisions suggest that a new objective of the DSP is to bridge the gap between planning and cost recovery by building an interim review element. If this is, indeed, the objective, Idaho Power feels strongly that more process is required in this docket to carefully and methodically examine the guidelines and determine if such an outcome can—or even should—be a major component of future DSPs.

COMMENTS ON GUIDELINE SECTIONS

In the sections below, Idaho Power offers comments only on those sections of the guidelines for which the Company proposes modification or otherwise has comment at this time. Finally, the Company notes that, to minimize confusion about versioning, references in these comments align to the redline version of Staff's proposed guidelines.

Guideline 1: Process and Timing

In this section of the guidelines, Staff prompts each utility to propose a date for its next DSP filing.[5] Idaho Power is especially grateful for cadence flexibility and tailoring—the primary issue for which the Company has previously voiced a preference. Considering Staff's objectives to have the next DSP incorporate guideline changes, including attempting to connect the DSP to other planning exercises, Idaho Power proposes March 6, 2026, as its next DSP filing date.

This date serves multiple purposes. First, it recognizes that Idaho Power's small Oregon service area remains stable, as reflected in the Company's 2022 DSP, which identified that, apart from a limited number of already planned distribution investments in 2023 and 2024, Idaho Power did not identify the next growth-related distribution project in Oregon until 2028.[6] A March 2026 filing date for the next DSP would allow time to reevaluate the 2026-2028 timeframe and identify potential distribution projects as warranted.

Second, March 2026 timing would allow Idaho Power to incorporate thinking and decisions from the next full IRP cycle (i.e., Idaho Power's 2025 IRP, which will be filed in the summer of 2025) and also cross-reference and consider the 2026 WMP, which will be filed at the end of December 2025.

Guideline 3: Community Engagement

Idaho Power is generally supportive of Staff's proposed revisions to the Community Engagement portion of the guidelines, formerly the Community Engagement Plan. As a matter of practicality, the Company appreciates and agrees with the proposal to strike the word "plan" from the section title. In the last DSP, developing a (community engagement) plan within a broader (distribution system) plan was, at times, confusing and redundant. Staff's streamlined approach

[5] Staff Proposed DSP Revisions, redline version, Guideline (1)(a), p. 2.
[6] Idaho Power's *2022 Oregon Distribution System Plan,* Table 5.2, p. 54.

in the guidelines does not diminish the importance of community engagement but does reinforce that community engagement is in service of the DSP.

Additionally, Idaho Power sincerely appreciates the addition of the guideline revision's sixth footnote,[7] which recognizes the Company's limited presence in Oregon and sets the expectation of a minimum of two community engagement meetings.

Additionally, Idaho Power would like Staff to consider modifying the guideline language such that it encourages utilities to streamline and converge relevant community engagement efforts. For example, it may be the most thoughtful approach for Idaho Power to have a distribution system discussion at wildfire-related education meetings within Eastern Oregon communities. With this idea in mind, the Company would recommend that community engagement count toward the requirement if communities are invited to participate in distribution-related aspects of the other planning efforts, such as the IRP or WMP. These are just examples; there will certainly be other circumstances in which a single meeting to accomplish multiple objectives may be the optimal approach to yield maximum customer and community participation.

Stated another way, if one of the goals of the revised guidelines is for utilities to find synergies across planning exercises and processes, then finding synergies in customer engagement should also be a goal. As Idaho Power has expressed previously in the DSP context, community engagement in Eastern Oregon is often a challenge—with a small customer base, oversaturation of meetings and information is a very real concern in the Company's outreach efforts and the Company has received stakeholder feedback to this effect. Guidelines that encourage utilities to streamline and align engagement across related issues is likely to result in the most participation for Idaho Power.

Idaho Power would also appreciate a definition of "larger projects" in part (d) of this section. Currently, the proposed language notes the kinds of projects that would be *excluded*.[8] It is unclear, though, if "larger projects" include projects of a certain dollar value, physical size, or notable prominence. A qualifier in this section would help ensure that Idaho Power will engage communities about the kinds of projects envisioned by Staff.

Guideline 4: Current System Data and Assessment

Idaho Power is aligned with some aspects of Staff's modifications in this section but identifies a few areas for clarification, refinement, or additional flexibility.

In the first sentence of Guideline 4, Staff proposes that utilities provide "progress of investment" in the current distribution system. This is a change from the prior language to provide "recent investment." It would be helpful if Staff could explain what kind of information was not received under the "recent" guideline that it hopes will be captured in the "progress" revision. Additionally, if the "progress" language remains, it would be helpful to note that Section 4 is about

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[7] Staff Proposed DSP Revisions, redline version, Guideline (3)(a), p. 4.
[8] *Id.*, Guideline (3)(d), p. 5.

historic spending, rather than planned future expenditure. Idaho Power interprets the guideline revisions as intending to capture forward-looking spend in the Near-Term Action Plan and Long-Term Plan sections. If this is not an accurate reading, the Company would appreciate additional language that captures Staff's precise objective and intention with Guideline 4.

In redlined part (h) of Guideline 4, Staff proposes that utilities provide a "summary of progress" on "investments, expenditures, and activities" from prior long- and near-term plans.[9] Idaho Power would appreciate a deeper explanation of the purpose and function of this new section of the guidelines, specifically whether the proposed summary includes a status update about every project identified in a prior DSP. Additionally, the Company would appreciate understanding whether Staff is specifically focused on comparing estimated project costs to actual project costs, should a project transition from planned to constructed.

In redlined part (g), Staff added subpart (ii), which suggests that "proposed investments" based on reliability be supported by the utility's Annual Reliability Report. Idaho Power believes that this addition requires more conversation, including discussion of whether this requirement is better placed in the Near-Term Action Plan section, where projects and distribution system actions are identified and discussed. Regarding the language, Idaho Power would note that a DSP does not identify "proposed investment" because the utility is not yet planning to take any actions nor spend any money. Rather, it identifies ways to meet system needs and estimates the possible expense of doing so. As an alternative, Idaho Power suggests that "estimated cost" would be more appropriate.

In redlined part (i) of Guideline 4, Staff proposes that future DSPs should include a submitted data component available for "public review."[10] Idaho Power proposes striking this, as the Company is unclear how the "summary of progress" on DSP projects in part (h) does not provide all the information necessary for the Commission to review and understand progress on various projects outlined in prior DSPs.

Additionally, the information requested in part (i) would typically be the basis of prudency review in a cost recovery filing. From its conversation with Staff, the Company understands that DSP projects themselves are not going to be authorized nor evaluated for approval within DSPs. Yet, the specific language to provide expenditure and investment data, as currently proposed in (i), is one example where the proposed guideline revisions transition the DSP from a planning document to pre-prudency review. In this regard, the proposed language appears at odds with Staff's suggestion that the purpose of the revised DSP guidelines is not an opportunity for early expenditure review in advance of a cost recovery filing.

Guideline 5: Forecasting of Load Growth, DER Adoption, and EV Adoption

Idaho Power is aligned with some of the proposed modifications to Guideline 5 but offers a few additional comments and suggestions for flexibility.

[9] *Id.*, Guideline (4)(h), p. 9.
[10] *Id.*, Guideline (4)(i), p. 9.

In part (a), Staff proposes that future DSPs forecast load growth at the feeder level, a level of granularity already provided by Idaho Power in its first DSP. However, this same feeder-level granularity is proposed for DER and EV adoption in part (b).[11] While it may be possible to identify the feeder location of some DERs that require an interconnection application, this is not necessarily a reasonable suggestion for electric vehicles ("EV") for Idaho Power, which has a limited number of EVs in its Oregon service area. It is worth noting that customers do not need to inform a utility when purchasing an EV nor when installing an EV charger. Rather, EV information is usually obtained through state vehicle registrations by zip code. As a result, the Company considers the feeder-level requirement too granular for DERs and EVs for Idaho Power.

Idaho Power suggests more flexibility for utilities in forecasting DERs and EVs. However, should this level of forecast granularity be a priority for Staff, Idaho Power would respectfully request an allowance akin to the one in Staff's proposed footnote 6. A similar footnote could exempt a small utility (by sales volume) from the feeder-level requirement for DER/EV forecasting.

It is also worth noting that the existing guideline language in part (vi) allows utilities discretion to determine the "methodology for geographic allocation."[12] Idaho Power considers this existing language reasonable and flexible enough to give individual utilities the ability to allocate DERs and EVs across their systems as appropriate for the unique conditions of their systems.

Guideline 6: Grid Needs

In Guideline 6, Staff proposes revising the section title from "Grid Needs Identification" to "Grid Needs"—a shift that Idaho Power finds reasonable and in keeping with the goal of capturing a utility's holistic distribution system needs. However, the Company identifies some areas of concern, as well as some individual language changes that may help with clarity.

First, in the introductory paragraph of this section, Staff's proposed language calls out "front-of-meter DER," a term that could cause confusion.[13] Idaho Power suggests changing this language to "utility-owned or third-party DER." Later in the same paragraph, when discussing the social and economic needs of communities, Staff proposes that …"the contributions [communities] can make to strengthen it should be addressed."[14] Idaho Power fully appreciates and recognizes the importance of integrating community perspectives, but would suggest that "addressed" be shifted to "considered"—a slight language change to reflect that some distribution system changes must be made for safety, reliability, or other reasons and may not be able to address all the needs of a given community.

In part (b)—and again in (d)—Staff proposes a requirement to identify and classify grid needs by asset class. For distribution-level projects, which can range from small efforts to substation construction, the term "asset class" is not logical, as a single project could encompass a variety of asset classes. Idaho Power suggests that the proposed guidelines strike "asset class"

[11] *Id.*, Guideline (5)(b), p. 15.
[12] *Id.,* Guideline (5)(b)(vi), p. 15.
[13] *Id.,* Guideline (6), p. 16.
[14] *Id.*

from the DSP language, as it is not a logical nor useful way of trying to understand distribution system projects or needs.

Under part (c), Staff proposes adding a host of different specific requirements of grid needs. Idaho Power considers this entire list—from (i) to (v)—highly prescriptive. A simple solution would be changing the language from "Discuss and identify anticipated grid needs, including the following…" to "Discuss and identify anticipated grid needs, such as the following, as relevant and applicable…" Such a small modification would yield the sorts of information Staff is hoping to acquire but would create space for utilities to respond only to relevant items rather than be required to explain a lack of connection.

Under part (c)(i), Staff has proposed information on "renewal" needs. Idaho Power would appreciate additional clarity about whether Staff is speaking to distribution upgrades, re-construction efforts, both, or something else entirely.

Guideline 7: Solution Identification

Idaho Power appreciates where Staff has attempted to tighten and streamline the Solution Identification section. However, the Company does not support the added line that "The solutions identified should correspond to future general rate cases."[15] This language directly indicates a prudency review function of the DSP and, further, assumes all projects identified in a DSP will be built. In reality, a number of on-the-ground considerations may change, making a project no longer cost-effective or appropriate. As a result, Idaho Power would propose a modification such as the following: "DSPs should strive to connect identified grid needs with distribution investments in future general rate cases, recognizing that distribution-level changes occur routinely and may require modifying or canceling solutions identified in prior DSPs."

Within part (a) of this section—and throughout the remainder of the guidelines—Idaho Power suggests uniform language to reference the "Near-Term Action Plan," as opposed to "near-term plan" or other variations.

Within part (c), the Company would like to better understand Staff's $1 million baseline for traditional solutions and conducting a "screen" for grid solutions.

Additionally, Idaho Power takes issue with the non-wires solution screening criteria. The Company is concerned that the "comparatively cost-effective" language does not appropriately center least-cost planning fundamentals. As an initial matter, Idaho Power does not know how to evaluate "comparative" cost-effectiveness. If a project is more expensive than an alternative, it is not cost-effective. Requiring utilities to present non-wires alternatives that are more expensive than traditional solutions could be misleading and potentially confusing, inviting inquiry into the details of system engineering, project design, and project costs. Earlier in this docket, stakeholders used such opportunities to suggest that the definition of "cost-effectiveness" should be redefined to incorporate such elements as social costs of carbon and other non-monetized

[15] *Id.,* Guideline (7), p. 16.

values. Considering the above, Idaho Power believes this subsection requires additional discussion and, in the absence of such a discussion, should be stricken from consideration.

Should this suggestion be perceived as a rejection of innovative thinking or lack of support for non-wires solutions, Idaho Power would note that it already screens for non-wires solutions for its distribution system projects, as it has explained in its DSP filings. To this end, the Company is installing four distribution-connected storage projects, one of which (the Weiser battery energy storage system) was evaluated to solve a grid need and selected as a "solution" within the Company's DSP from 2022.[16]

Guideline 8: Near-Term Action Plan

Staff has proposed a significant revision to this section, with a detailed list of requirements for projects that would fall within the DSP Near-Term Action Plan window. At a high-level, the added language aligns with the kinds of information a utility would supply to prove prudency. As such, the Company does not believe it is appropriate to require such detailed information without further conversation.

At a minimum, the Company reinforces its earlier comment that the DSP is not a document that identifies future investment and, with this in mind, the language within Guideline 8 warrants modification. One example comes in part (a)(3), which asks for "investment/expenditure amount." DSP projects are identified and can have project *estimates*, but those estimates do not necessarily translate to investment amounts. As a result, Idaho Power would suggest that this particular line change to "High-level project cost estimate."

Idaho Power also proposes striking section (c) in full, as the language explicitly asks the utility to prepare to justify DSP items in future general rates cases. Idaho Power welcomes additional conversations with Staff and other stakeholders to come up with reasonable language that can get closer to Staff's intent without turning the DSP into a precursor to cost recovery.

Guideline 9: Long-Term Plan

Reviewing Staff's proposed additions to the Long-Term Plan, Idaho Power notes that the requirements listed under the Near-Term Action Plan appear to have been duplicated. The Company would appreciate additional discussion with Staff to better understand the new objectives for the Long-Term Plan section. A simple solution would be striking all language from "The roadmap should include…" through (iii). This stricken section includes the duplicative Near-Term Action Plan language, as well as an additional requirement for utilities to connect items identified in the Long-Term Plan to investments in future general rate cases. Idaho Power has concerns with this language for the reasons noted previously but is open to discussion with Staff to develop revised language that achieves a reasonable and feasible outcome for the Long-Term Plan section.

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[16] Idaho Power's *2022 Oregon Distribution System Plan,* Table 5.1, p. 53.

NEXT STEPS AND CONCLUSION

Idaho Power thanks Staff and the Commission for this opportunity to comment on the UM 2005 draft DSP guideline revisions. The Company appreciates that Staff would like to make progress on and resolve the revised guidelines by late July.[17] However, this docket has been idle for many months and, rather than accelerate through significant proposed revisions, Idaho Power believes more process is warranted—both through discussion (which could come in the form of workshops or individual conversations between parties and Staff) and additional comment opportunities on the proposed revised guidelines.

Based on the significant changes proposed by Staff and the substance of Idaho Power's comments in response, the Company respectfully requests additional process to ensure future guidelines and guideline language can be considered and revised with a shared understanding of ultimate DSP objectives.

Idaho Power looks forward to ongoing work with Staff and other stakeholders to develop reasonable and achievable revisions to the DSP guidelines.

If you have any questions regarding these comments, please contact me at 208-388-2872 or awilliams@idahopower.com.

Kindest Regards,

Alison Williams

AW:cd

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[17] Staff's Docket Announcement and Schedule, April 26, 2024.

ATTACHMENT B
to
JOINT UTILITIES’ COMMENTS

(PGE’s DSP Comments)

Portland General Electric
121 SW Salmon Street • Portland, OR 97204
portlandgeneral.com

May 31, 2024

Via Electronic Filing

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

Re: UM 2005 – Portland General Electric Company's comments on Staff proposed DSP Guideline revisions

Dear Filing Center:

Enclosed for filing in the above-referenced docket are Portland General Electric Company's (PGE) comments on Staff's proposed DSP Guideline revisions.

PGE has responded to each category of DSP requirements in addition to general comments on the proposed revisions. PGE looks forward to engaging in further discussion of these topics at the upcoming UM 2005 workshops.

Kristen Sheeran, PGE's Senior Director of Strategy Integration and Planning, leads PGE's DSP work. Please direct any questions or communications regarding these comments to: pge.opuc.filings@pgn.com.

Sincerely,

/s/ Riley Peck

Riley Peck
Senior Manager, Regulatory Strategy
Resource & Regulatory Strategy

Table of Contents

1 Introduction

PGE thanks Staff for the opportunity to revisit the Distribution System Plan (DSP) Guidelines. The proposed guideline revisions streamline and focus Staff's guidance and should help ensure utility distribution system plans provide the insights Commission, Staff and stakeholders need to more clearly understand how utilities plan and prioritize their distribution system investments. We understand from our engagements with Staff that DSP guidance is intended to remain an iterative process, subject to feedback and change. Thus, the guidelines retain the overall goals Staff initially expressed in evaluating PGE's 2016 IRP yet can be expected to continue to evolve beyond the current revisions in future years.

We also thank Staff for meeting with us on multiple occasions to help PGE better understand the proposed revisions, particularly Staff's intent regarding the expressed connection between DSP and future General Rate Cases (GRC), which features prominently in the language of the revised guidelines. From those discussions with Staff, we understand the connection is not intended to serve as a pre-prudence assessment of distribution investment, but rather to help Commission Staff and others understand how a line-of-sight for distribution system investments found in a GRC may be traced back to a utility distribution system plan, notwithstanding the fact that plans are subject to adjustment and refinement in response to a variety of external factors as they are implemented. The DSP is a Plan, not a report or an investment vehicle, but it can be a precursor to both, just as the Integrated Resource Plan (IRP) is a precursor to other utility investment and operational activity.

PGE's detailed comments on Staff's proposal for the DSP to provide a connection to the GRC can be found below, but in short, we emphasize that the DSP and the GRC should not be connected for the purposes of investment pre-approval by the Commission. The DSP should communicate our vision and the associated plans to meet that vision through possible distribution system investment and DER development. If Staff has an interest in regular updates regarding the execution of plans and projects found in the DSP, PGE is willing to discuss the formation of a more structured regular progress report for that purpose.

Another significant element of Staff's proposed revisions to DSP guidance relates to non-wires solutions (NWS). PGE is committed to using alternative technologies and new approaches using existing technologies to empower customers with a new service paradigm. NWS can encompass one aspect of these new approaches. However, PGE's most important charge is safe and reliable service. Non-wires solutions conceptually can work in some circumstances, and our assessments of NWS within DSP Part 2 showed how a NWS could be deployed to address a grid need. However, as a practical matter NWS present a host of open and unanswered questions, the most significant being where they can be successfully incorporated into the 8,760 annual hours of grid operations in a safe, reliable and resilient manner. If customer-sited DERs are involved in a NWS, a host of questions arise, including what customer participation requires and how the customer value proposition differs from that of participating in a PGE program. PGE, and all utilities, need space and opportunity to understand how to build dependable NWS infrastructure that can meet operational standards. The DSP should be part of the process that creates these learnings, but implementation of NWS cannot yet be pre-determined as a preferred outcome for any given distribution system investment decision.

In conversations with Staff and other utilities, PGE has raised concerns regarding the procedural pace set for issuance, review and comment and finalization of the proposed DSP guideline revisions. While PGE appreciates Staff's availability to discuss the draft guideline revisions, additional opportunities to engage in the process before adoption of guidance would result in less need for iteration later, clearer direction and understanding among utilities, and less contention and misinterpretation in the upcoming DSP cycle.

1.1 Focus of DSPs

Staff states an intent to use DSPs to influence utility decisions prior to their implementation and lay groundwork for rate recovery, through improved understanding of major drivers, level of spend, prioritization strategy and benefits driven by planned operational budgets and system investments.[1]

PGE agrees that these objectives are consistent with Staff's initial vision for the DSP and guidance adopted in Order 20-485 and offer a foundation for a productive and accessible process. However, the process to develop the first DSPs highlighted the complexity, nuance, and lack of ability to generalize across utilities. While there are common challenges, each utility has a unique service area with varying circumstances and needs, and each utility has its own practice, process, and structure of distribution system planning to address those needs.

A balance should be established between strengthening the collaborative process that characterized the initial DSP cycle and creating new, detailed reporting requirements that may prove unintentionally burdensome and redundant, adding little value. Some new language in the draft revisions also clearly implies a pre-prudency review, which Staff has explicitly told PGE is not their intent. We continue to believe that the most important area of focus of the DSP is on how the system is changing and evolving to meet customer and system needs. PGE remains open to providing information about planned activity and would welcome further process to develop guideline language that strikes the right balance

[1] Cite to Staff executive summary, available at: https://edocs.puc.state.or.us/efdocs/HAH/um2005hah328141024.pdf

between planning and reporting to provide the necessary level of information in a form that is understandable and usable for Commission review and oversight.

In these comments, we have provided context for several areas where the draft revisions should be updated to improve effectiveness, which are summarized in Appendix A.

1.2 High priority questions

In conversations with Staff and through issuances within this docket Staff frames DSP objectives, and the guideline revisions that support these outcomes, on four "high priority questions" related to grid needs, expenditure decision-making and prioritization, and proposed investments and expenditures. Staff states that they seek to better understand the following:[2]

- How is the Company prioritizing and containing spend while making decisions across multiple objectives, such as load growth, aging infrastructure, policy obligation, and heightened demands?
- How are the decisions that the Company is making related to distribution assets interacting with non-distribution asset strategies? Essentially, what alternatives to distribution investment could be considered and if certain distribution investments are made, what impacts do they have on other network assets?
- How is load growth, particularly from large commercial and industrial customers, impacting the Company's grid needs, costs, and strategies? What would the plans look like if those large loads were not being considered? What barriers to modern technology exist and how can the planning and commissioning process mitigate those barriers?
- How is the plan informed by and/or informing the PUC's work to incorporate resilience considerations into investment planning? How are Wildfire Mitigation Plans informing/informed by the Company's DSP?

Rather than flowing directly into guidance provisions, these Staff questions are more cross-cutting and raise several strategic issues, on which we comment below.

Staff's first question speaks directly to the competing objectives inherent to making prudent investments to maintain the reliability of the distribution system. PGE provides significant information on this question in rate review proceedings, but PGE understands that Staff is seeking to use DSPs to obtain greater insight into upcoming decisions. To this end, through the initial DSP cycle, PGE provided substantial detail on our capital planning processes.

[2] Cite to Staff executive summary, available at: https://edocs.puc.state.or.us/efdocs/HAH/um2005hah328141024.pdf

Rather than pre-prudence review of individual projects, the DSP focus should continue to be on how the Company identifies and prioritizes needs and develops different types of solutions to address them. And while PGE's investments span a range of types, investments related to upgrades to infrastructure to accommodate broad load and hosting needs is the highest-value category to focus on in the transparent DSP planning process.

PGE also recognizes Staff's consistent aim in these proposed revisions to emphasize the through-line of information presented in DSPs to eventual GRCs. PGE provided such information in an information request response following DSP Part 2 and has engaged in collaborative discussions with Staff to explore how to find a meaningful path forward to offer such data in a useful format and at an appropriate level of granularity. From these conversations, we want to re-emphasize three important caveats to any expectations for sharing project-level information in DSPs:

1. **Purpose of sharing.** Staff, across several revisions to the DSP Guidelines has maintained that activity and spend found within the DSP "correspond to future general rate cases". After the inaugural filing of the DSP Part 1 and Part 2, having submitted detailed information on all distribution projects through an information request, PGE subsequently submitted a general rate case or rate review. In meeting with Staff PGE proposed a spreadsheet connecting the projects by project number and DSP Part 1 and Part 2 categories to the Distribution System projects for which PGE is seeking cost recovery in UE 435. Staff had an opportunity to view the spreadsheet but not inspect, reviewing largely for the format and structure of the product. Here Staff indicated that such a product would be helpful in understanding and being able to connect and therefore review with better context how the items listed in utility DSPs could be tracked from Plan to recovery. Further, PGE and Staff understood that the reason for the ability to connect DSP plan spend with GRC cost recovery spend was to track how the utility carries out the plans found in the DSP, making a direct connection to the activity for which PGE seeks recovery. This helps Staff and stakeholders of both dockets understand how PGE is executing, and at what cost, the plans and strategies found in the DSP. PGE and Staff understood that the submittal of planned project cost information in the DSP is not pre-prudence review conducted by Staff but a necessary part of Staff insight and understanding as part of their regulatory oversight role. PGE agrees that this approach is a proper, well-founded, well-structured balance.

2. **Recognition that cadence between DSPs and GRCs is not predictable**. PGE noted and Staff stated an understanding that current practice of frequent rate review filings will not always be the practice and that DSP filings and GRC filings may not have the same cadence as they do now, which at present makes for easier follow-up and therefore tracking between the two dockets. The guidelines as written contemplate

this as they note revision and iteration in the future to manage changes in practice, policy and need.

3. **Flexibility is essential for distribution planning.** PGE notes that planned activity must often change either as budgets change, emergency situations dictate spend, new load and distributed energy resources emerge or new technology and knowledge of system and equipment state informs decisions from plan to implementation. This means not all planned activity described in the DSP will necessarily appear – or be budgeted at the same level – in the next GRC. Some activity described in a DSP may not be brought forward for recovery until a later GRC, and some planned activity may never be implemented as needs, resources and technologies change and are re-prioritized to provide reliable service to customers. In conversation Staff and PGE recognize this issue as one that can be addressed both through the filing of the DSP and regular engagement with Commission Staff regarding changes from planned activity found in the most recent filed DSP.

The following sections elaborate on those sections of Staff's proposed DSP guideline revisions where PGE recommends changes. Our comments follow the sections of the current guidelines as listed by Staff in Table 1 of their draft revisions.

2 Process and Timing

PGE agrees with the need to update key provisions of the current "Process and Timing" guidelines and appreciates the flexibility provided by Staff's draft revisions.

Timing

We shared, during development of DSP Part 2, that PGE's annual planning cycle concludes in the June/July timeframe. As such we propose filing our DSP in the September/October timeframe on an ongoing basis. In keeping with the original DSP guidelines, PGE expected to file its next DSP within two years of Commission "Acceptance" of the last DSP, which was February 2023. According to that guidance, PGE expected to file its next DSP by February 2025. Based on that expectation, PGE began developing its DSP in July 2023. Specifically, **we intend to continue with the development of a DSP that we submit in September/October 2024 and submit the next DSP in September/October 2026**. PGE's position is that the DSP should be both a detailed plan of the DER resource development goals set out in the Integrated Resource Plan (IRP) and part of an informative planning cycle for the next IRP.

As we engage in this current process of guideline revisions, we will consider and account for the extent to which PGE's 2024 DSP submission can address the revised guidelines.

Process

The proposed schedule for revision of the guidelines is very compressed. It took several years with extensive stakeholder input to develop the guidelines currently in place. While PGE agrees with Staff on the need for iteration and the ability to iterate on a much faster timeline than the process that resulted in our current DSP guidelines, issuance of draft guidelines with only one comment period is too hasty and could lead to the need to revisit the guidelines much sooner than if we take additional procedural steps now to assure effectiveness, understanding and sustainability of the new guidelines across all affected utilities. Therefore, PGE proposes Staff lead at least one workshop, likely followed by a comment period, to review the proposed guidelines and collectively develop new proposed language.

PGE proposes for consideration, understanding that additional conversation and regulatory adjustment will be needed, that the guidelines and regulatory structure allow utilities to combine the Transportation Electrification Plan (TEP) and the Flex Load Multi-Year Plan (MYP) into the DSP, where appropriate to their planning processes and needs. This approach could give a holistic review of all resources, loads and activities affecting the distribution system, thereby allowing the Commission and Staff to see how PGE's investments affect one another and can be stacked to provide the greatest planned benefit.

For PGE the MYP and the current DSP cycle are similarly situated. If their cycles continue on a two-year basis these plans can be easily consolidated. PGE views the MYP as a DER resource action plan which can easily be incorporated into the DSP Action Plan. This approach lessens the regulatory review burden by addressing the need to submit two overlapping filings which outline what DER activity PGE intends to undertake. Through our 2024 DSP filing PGE will show how the two filings can be consolidated. However, PGE understands that we have an obligation in UM 2141 to file a MYP this year and will make that filing at the same time as our 2024 DSP. If officially consolidated the approval of the MYP budget can be included as part of the Commission decision to accept the DSP.

Similarly, the TEP outlines investments in TE infrastructure that directly affect distribution investments. Consolidating these plans would yield a series of benefits including a more holistic plan which outlines investments in the distribution system, investment in distribution resource development and investments meant to support clean transportation that directly affect the distribution system and investment decisions. For example, distribution system investment to support heavy-duty vehicle (HDV) charging infrastructure should be coordinated with system future needs and future and present community investment and corresponding need.

The earlier these plans are connected the earlier our regulatory community can understand how strategic, planned investment might work in the face of forecasted, known new load additions. This would inform not only what investment might be needed but how to assure that investment brings the greatest benefit to customers, community and the system at the right time while capturing the greatest combination of immediate and long-term benefits.

Through our work with Community-based Renewable Energy (CBRE), demand response, energy efficiency and our current internal work on Community Benefit Indicators, PGE is gaining further understanding about how stacked investments can serve multiple needs.

For PGE, combining the TEP and MYP with the DSP could make these investment decisions clearer to the Commission, Staff and stakeholders and reduce the regulatory review burden presented by having these activities separated.

3 Community Engagement Plan

Staff's proposed DSP guideline revisions largely left the DSP external engagement requirements unchanged, with some consolidation of requirements from other guideline sections. We see from the revisions that Staff is balancing community and stakeholder engagement with stakeholder bandwidth by upleveling the engagement with a more holistic, company-wide approach. PGE supports this approach and has made investments and transitioned work and responsibilities to better manage engagement such that it is more approachable and relevant for those concerned. PGE will fulfill its requirement of hosting four public stakeholder engagement meetings during plan development.

PGE supports Staff's proposal to incorporate engagement into ongoing community and stakeholder processes such as Clean Energy Planning (CEP) and local-area planning, emphasizing the potential for community and in-person meetings.

In our commitment to advancing community engagement, PGE aims for a holistic approach, drawing learnings from other venues like the CEP/IRP Roundtable and Community Benefits and Impacts Advisory Group (CBIAG). By leveraging these insights, we strive to evolve our external engagement efforts to enable a human-centered approach to distribution system planning. To address community and stakeholder groups, PGE reorganized internally to form a Community Engagement and Impact Team to strategically align outreach and engagement efforts to the communities we serve. The team is currently focused on strengthening and establishing relationships with community-based and community-serving organizations. Additionally, this group aims to increase PGE's presence in the community to better understand and learn about their needs and priorities, while supporting our goals.

PGE is committed to enhancing communication and collaboration with communities we serve and with interested stakeholders. This includes everyone who has experience and expertise in the evolving landscape of Oregon's energy sector and those who may not have had clear opportunities or the resources to engage with us in the past. As part of a broader effort to deepen our commitment to direct and intentional community engagement, within the guidelines set forth for us by the Oregon Public Utility Commission, we made the following changes to our external engagement forums:

1. **IRP Roundtable** – We will continue hosting our IRP and CEP Roundtable sessions for stakeholders who want to discuss, understand, and provide input on in-depth technical issues and decisions relating to our IRP and CEP. These, generally monthly, sessions will continue focusing on technical outreach and feedback solicitation, with materials provided in advance to facilitate meaningful discussions. We will be using our feedback forms to report on what stakeholder input we have received and whether (and how, if applicable) we plan to incorporate it, so that everyone can understand our reasoning.

   Details: Every month, virtual 3-hour meetings via Zoom.

2. **Distribution Workshop** – We will begin hosting regular Distribution workshop sessions for community members and stakeholders who want to discuss, understand, and provide input on in-depth technical issues and decisions relating to our Distribution System Plan, Flex-load Multi-year Plan, Transportation Electrification Plan, and other demand-side programs and resources. These bi-monthly sessions will focus on technical outreach, education, and feedback solicitation, with materials provided in advance to facilitate meaningful discussions. We will also implement a transparent reporting mechanism on how feedback is or is not incorporated into our plans, so that everyone can understand our reasoning.

   Details: Every two months, virtual 2–3-hour meetings via Zoom.

3. **Community Engagement** – The Learning Labs will be reformatted and refocused to be in person. These sessions will emphasize engagement with groups and individuals to build intentional relationships with communities. We will provide content on request and information on energy topics, PGE initiatives and activities, and opportunities for community involvement and collaboration on projects such as NWS, Demand Response/Flexible Load, and CBRE installations.

   Details: To be scheduled upon request, in person, outside work hours, or at community venues.

The goal of tailoring our engagement strategies to the unique needs of communities and stakeholder groups is to better serve interests and foster meaningful collaboration. As we implement these changes, we remain committed to regularly evaluating the effectiveness of our engagement strategies.

In compliance with the Commission's recent order in the 2023 Clean Energy Plan and Integrated Resource Plan in LC 80, we will collaborate closely with Staff, stakeholders, peer utilities, and the CBIAGs within a dedicated working group. Together, we aim to develop actionable improvements to community and stakeholder engagement, informing future DSP stakeholder and other community engagement initiatives.

4 Baseline Data and System Assessment

Staff removed a number of reporting elements from the Baseline data requirements due to their availability in other reports. The significant addition to Baseline data requirements requests that utilities demonstrate, through references to the data, how investments delivered improvements if the investment was driven by the reliability data. PGE found the baseline data portion of DSP Part 1 to be a considerable time commitment and believes it is appropriate to modify Staff's proposed language to remove duplication, avoid phrasing with overly narrow implications, and set appropriate refresh cycles.

PGE recommends removing guideline 4.a) as it is duplicative of the information that is requested in Grid Needs guideline 6.a) and was provided in DSP Part 2, Chapter 1 Distribution System Overview and Chapter 4 Grid Needs Analysis.[3] For example, revised guideline 4.a) states "*The utility should provide… A description of any currently used system assessment practices (such as system reliability assessments, system asset health assessments, etc.) that are utilized in identifying grid needs.*" and revised guideline 6.a) states "*A utility's Distribution System Plan should: a) Document processes used to assess grid adequacy and identify grid needs, b) Discuss criteria, methods, and tools used to identify needs…*".

[3] DSP Part 2, available at: https://downloads.ctfassets.net/416ywc1laqmd/2Fr2nVc4FKONetiVZ8aLWM/b209013acfedf1125ceb7ba2940bac71/DSP_Part_2_-_Full_report.pdf

PGE recommends a revision to the cadence of providing the data identified in revised guidelines 4.b), 4.c) and 4.d). The information provided in the Baseline data and system assessment are relatively static, i.e., the numbers and conditions do not change that much or that often. For example, the information below was provided in DSP Part 1, Chapter 1 System Overview:

Table 2. Summary of distribution assets as of Q1 2021

Asset classes	Number of assets	Average age of assets[1]	Average service life[2]
Substation structures	N/A	N/A	65
Substation transformers	407	38	55
Circuit breakers	1,617	21	55
Other substation equipment	9,967	30	65
Distribution poles	203,615	41	48
Overhead transformers	108,500	29	50
Reclosers and sectionalizers	422	8	50
Voltage regulators	55	9	50
Capacitor banks	689	27	50
Other open hole (OH) conductor devices	175,492	21	48
Underground (UG) transformers	71,153	28	55
UG conduit	243,273	12	80
Other UG conductor devices	3,411	19	55

1. Average age is the actual average age of all in-service assets within each group as of Q1 2021.
2. Average service life is derived from a five-year depreciation study and used for cost-recovery purposes.

Collecting all these data is labor intensive. We recommend extending the timeline for providing this data to not more often than every five (5) years or discussing an alternative mechanism to provide insight into these data.

PGE understands why **guideline 4.e)** specifies the categories for reporting the past five years of spending, i.e., creating a common framework for all utilities to report against. We also learned, through conversations with other IOUs, that even when using a set of categories provided by the OPUC, the IOUs do not map current investments to the provided categories the same way. For example, a project that PGE assigns to the category of "System expansion or upgrades for capacity" may be assigned to the category of "New customer projects" by PacifiCorp and assigned to the category of "System expansion or upgrades for reliability and power quality" by Idaho Power. Each utility's service area, customer base and system operations are significantly different, and each has its own methods for assigning projects to categories.

PGE recommends that guideline 4.e) be modified to exclude the categories provided in subparts i) – vii) and utilities be allowed to report past expenditures in the categories that reflect their individual project and financial management practices. PGE also notes that, with the DSP being submitted every two years, much of the data provided will overlap with past and subsequent DSPs. **PGE suggests that the language of this guideline be modified to provide the data from one DSP to the next, so there is no overlap**.

PGE recommends that 4.g.i) and 4.g.ii) be removed from the guidelines as they are overly prescriptive "*i) Any descriptions of reliability challenges and opportunities in the Distribution System Plan should cross-reference…*" and "*ii) Any proposed investments based in whole, or in part, on reliability improvements must demonstrate…*". Instead, PGE recommends that the OPUC continues to use the Annual Reliability Report to maintain a view of what is happening on the elements of the system that are described there.[4]

5 Forecasting of Load Growth, DER Adoption and EV Adoption

The methodology and granularity identified in Staff's revised guidelines align with the information we provided in DSP Part 2. The major items of note in the revised guidelines are related to the locational decomposition of the forecast and its relationship to the CEP/IRP process. We agree with the decision to improve granularity of DER forecasts to the feeder-level, and so focus our comments below on the relationship of load forecasting, the DSP, and CEP/IRP processes.

Our DSP Part 2, Chapter 3 covered PGE's process for forecasting load growth and DER adoption for purposes of distribution planning.[5] In it, we described the process of taking the corporate load forecast (at the system-wide level) as an input, and then allocating it down to the distribution level in order to account for past trends and known customer load additions. In addition, we discussed our process for forecasting DER growth (including EVs) at the locational level using our AdopDER model and related processes.

Staff's draft **guideline revisions 5.a.iv) and 5.b.v)** state that in future DSP filings, *"[t]he load forecast should include data, inputs, and assumptions from the Company's most recent IRP/CEP, which should be clearly listed in the DSP*." PGE appreciates Staff's efforts to draw further connections between the DSP and the CEP/IRP, but does not agree with the recommendation that utilities base DSP forecasts off of CEP/IRP data, inputs, and assumptions, for the reason that these planning activities occur on different timelines and therefore the inputs, data, and assumptions may be out of date by the time a DSP is developed and filed. Moreover, PGE's load forecast is actually the key input to both the DSP and the CEP/IRP, which is updated regularly— sometimes two or three times per year. **PGE recommends that the guidelines should reflect using the most up to date and accurate**

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[4] PGE Annual Reliability Report, available at: https://edocs.puc.state.or.us/efdocs/HAQ/re113haq161237.pdf
[5] DSP Part 2, Chapter 3, available at: https://assets.ctfassets.net/416ywc1laqmd/46I2n65SyTv3TUMMdq1l55/a993aebb7b7a84ebd3209d798454a33a/DSP_Part_2_-_Chapter03.pdf

input assumptions available at the time, rather than pointing backwards to CEP/IRP inputs, data, and assumptions.

PGE believes that Staff highlights an important area of consideration in calling attention to the linkages between the DSP and CEP/IRP. The DSP is informed by and will inform the CEP/IRP process regarding the availability of distribution-sited resources, load growth and distribution investments that can enhance the benefits of DER and extend benefits to customers and community. Currently, the DSP and the CEP/IRP are connected most directly in the form of DER potential. In its 2023 IRP Action Plan, PGE included a variety of customer-level DERs spanning 212 MW of demand response/flexible loads, 130 aMW of energy efficiency, and 155 MW of CBRE. Much of the CBRE potential was from front-of-the-meter DERs like community-scale solar and hybrid solar-plus-storage resources that connect directly to distribution voltages and therefore can provide resilience benefits to communities.

However, PGE notes that some DER forecasts (as currently defined in the DSP guidelines to include EE, EVs, DR, solar PV, and storage) are primarily market-driven forecasts of potential load impacts, for example solar PV adoption and EVs. Although there is a logical relationship between the DSP and CEP/IRP in this regard, it is important to maintain flexibility when selecting input data and making foundational assumptions. For example, the previous CEP/IRP began with the latest forecast for DER adoption provided by AdopDER for the DSP Part 2. However, during the course of the CEP/IRP process, the Inflation Reduction Act was passed and changed incentives for DERs, causing PGE to update the forecasts for the CEP/IRP accordingly.

Therefore, **PGE recommends the final guidelines highlight the direct connection and virtuous cycle between the planning activities when it comes to load growth and DER potential, but allow latitude in developing appropriate data sources and inputs that reflect the quickly changing market realities facing the electricity sector**. Specific examples of this virtuous cycle include how distribution investments can accelerate DER deployment and potentially reduce costs of achieving the targets for DER acquisition identified within the CEP/IRP, and how community benefits may be maximized by locational deployment of certain technologies.

6 Grid Needs Identification

The Grid Needs revised guidelines are largely in line with the guidelines that were addressed in DSP Part 2. **PGE recommends removing "… by asset class" from guideline 6.b).** There are grid needs that do not map to an asset class, such as Feeder or Substation needs. Although PGE does evaluate risks for some asset classes as discussed in DSP Part 2, Section 4.4 Assessing reliability and risk:

Figure 31. Existing asset models

Economic life cycle models	
Substation assets	**Distribution assets**
✓ Transformer	✓ UG cable
✓ Circuit breaker	✓ Line transformer
✓ Relay system	✓ Recloser
✓ SCADA system	✓ Regulator
✓ Switch	✓ Switch
	✓ Structures
Geographic risk	**Business case tools**
✓ Vegetation/ weather risk	✓ Risk register
✓ Wildfire risk	✓ Integrated planning tool
✓ Animal risk	
✓ Public risk	

There is a limit to the granularity of information that can be safely published with respect to grid needs. Providing too much information can expose PGE to vulnerability from bad actors. This exposure is discussed in PGE's Annual Reliability Report. To that end, **PGE recommends that revised guideline 6.c) include language that recognizes this constraint, such as "c) Discuss and identify anticipated grid needs (to the extent such identification does not violate customer privacy or NERC/CIP protections)…".**

PGE understands the OPUC's interest in establishing a "thru-line" between grid needs identified in the DSP and a subsequent general rate case. **PGE recommends removing the "thru-line" language from revised guideline 6.d).** Grid needs may be aggregated into a single solution or divided across multiple solutions. Grid needs also are not traced with a unique identifier, such as the unique number we use to track projects or capital investments. **Also, similar to guideline 6.b), "asset class" should be removed.** The revised guideline language should be *"d) Provide a summary table of each prioritized grid need ~~by asset class and~~ specifying the timing of need. ~~The summary table should aid Staff and stakeholders in finding a thru-line from grid needs reported in a DSP to investments seen in future general rate cases.~~"* As seen within UE 435 distribution project numbers do remain consistent and can be used to track which planned distribution activities outlined in the DSP are subsequently found in a GRC filing.

7 Solution Identification

PGE recommends modifying the introductory language for the Solution Identification revised guidelines as follows:

"The utility should assess grid needs to determine ~~cost effective~~ solutions as follows:"

PGE performs a benefit cost analysis (BCA) to determine the least-cost solution, from the range of available solutions, to address prioritized grid needs. We believe that performing a BCA achieves the OPUC's objective of the lowest-cost solution, but is not the same as a "cost effectiveness" test. The current cost effectiveness test for EE, DR and DERs is narrowly focused on programmatic structures. Our current BCA practice is broader and has the capacity to incorporate the benefits and costs of co-deployed DER.

PGE recommends the following modifications to revised guideline 7.a):

"*a) Document the process to identify the range of possible solutions to address priority grid needs ~~and discuss how this process was applied to identify the proposed solutions in the Long- term and Near-term Plans~~*"

This recommendation essentially reverts to the original guideline language. We do not believe the revised language would result in delivery of any additional information. For example, in DSP Part 2, Chapter 4 Grid needs analysis, we detailed the analysis that led to the identification of 41 grid needs. Using our prioritization matrix, we identified 12 priority grid needs. We developed solutions for the 12 prioritized needs and included those projects in the Near-term Plan. There is not an additional decision-making step between the prioritized grid needs and the Near-term Plan. The Long-term Plan, on the other hand, is not informed by the grid needs. The Long-term Plan serves the role of strategically guiding how we think about solutions.

PGE finds recommendation 7.b) to be duplicative of 7.a) in that, per PGE's standard practice, we consider all solutions that are appropriate to address the grid need in the timeline required. If the guideline is to remain, we recommend removing the word "First", as it suggests an order of operations that is not necessarily informed by our current practice.

We share the OPUC's interest in pursuing the use of distributed energy resources (DERs) to address grid needs. We believe the exercise of providing NWS concept proposals in DSP Part 2 was informative and delivered important learnings. We know, at this time, that we currently do not have the tools or processes to systematically implement NWS that could reliably address grid needs using customer-sited DERs in the required timeframe. As such **we recommend removing revised guidelines 7.c) and 7.d)** and turn the focus to PGE's Smart Grid Testbed (SGTB) to advance the development of the capabilities required to enable a cost effective, reliable NWS.

PGE understands Staff's interest in NWS as NWS can provide local investment and local benefit when structured to include the community and customers affected by local utility infrastructure. PGE's vision of a modernized grid capable of moving energy bi-directionally carries the greatest benefit to the greatest number of use cases and customers. However, NWS are highly specific to need characteristics which tend to evolve quickly and are dependent on timeline and community engagement challenges. After considering several potential NWS projects, PGE, like other utilities, does not currently have the operational experience with NWS (that include customer-sited resources) to rely on their structure and ability to deliver services critical to safe and reliable system operation supporting our SAIDI and SAIFI requirements. Therefore, to accelerate development of NWS tools and operational capabilities, PGE sees value in using the SGTB.

The Testbed thus far has proven highly valuable to PGE, the Commission and stakeholders. Because the Testbed is developed as a collaborative design effort between PGE and the stakeholders seated on the Demand Response Review Committee (DRRC), any work that is conducted within the Testbed is informed and designed to meet the questions presented by a board of informed experts, whether technical, social or regulatory. Second, the Testbed has proven that it can build, deploy, test and evaluate a host of technical and other projects at low cost.

Currently, the SGTB is undertaking effort through a project called the Flexible Feeder and the US DOE funded SALMON project that will give us insights into some of the operational capabilities and some of the deployment timelines and challenges of the structural components of an NWS.[6] Neither the Flexible Feeder nor the SALMON project were explicitly developed as NWS.

The second phase of the Testbed, which includes the Flexible Feeder/SALMON project, was developed around a yearly budget that was less than Phase I while delivering many more lessons learned and technical insights over the proposed 5-year schedule. Phase II of the Testbed is on track to underspend.

The Testbed has attracted investment and collaboration from other parties and has helped inform regional parties in their pursuit of DER development and customer engagement. Testbed funding is tightly controlled through the DRRC and the Commission, as funding for any new project is not released until the DRRC, Staff and the Commission approve of the project details. Therefore, the Testbed can be utilized to better understand what purposes NWS can meet and what operational capabilities and grid services NWS can provide while developing the proper tools to better understand how to evaluate, plan and invest in NWS to achieve stated benefits and operational capabilities. PGE will discuss with the DRRC how best to advance NWS work within the SGTB.

8 Near-term Action Plan

PGE recommends modifying revised guideline 8.a. ii) to reflect a higher threshold for providing additional project details. PGE suggests changing the threshold from $2M to

[6] PGE's Flexible Feeder Project, available at: https://edocs.puc.state.or.us/efdocs/HAH/um1976hah151930.pdf

$10M, because more than 80% of all distribution spending can be captured, described and listed if the threshold is set at $10M. Raising this dollar threshold will serve Staff's need to be properly informed of planned activity that may significantly affect rates in the future, community projects and investment and customer enablement without overloading Staff with technical information to review in a DSP.

PGE recommends that revised guideline 8.a.ii.1) be revised as follows:

"*Narrative description of the actions included in the Action Plan ~~including foundational assumptions and key barriers or constraints (including financial, technical, organizational) and mitigation plans~~.*"

The information requested is not available at the time the project is provided in the DSP Near-term Action Plan (NTP). PGE's investment approval process is gated. Projects are approved to proceed with the design phase. After the design is complete, a construction plan can be developed and more specific estimates/timelines produced. The project then requests approval for funding to proceed with construction.

PGE recommends removing revised guideline 8.a.ii.4) as it is duplicative of the information provided in the Grid Needs and Solution Identification processes. The process for prioritizing investments also was provided in DSP Part 2, Appendix L Capital planning process.[7]

PGE recommends removing revised guideline 8.a.ii.6) pursuant to the fact that we do not yet have the tools or processes to implement an NWS that relies on customer-sited resources (see explanation above in section 7 Solution identification). We do support continuing to discuss with Staff and Stakeholders the development of NWS capabilities.

PGE recommends removing "asset class" from revised guideline 8.b):

"*Projected spending: Provide the projected cost and timeline ~~by asset class~~ to implement the Action Plan. Provide a description of anticipated requests for cost recovery.*"

Regarding Staff's interest in establishing a through-line to future GRCs, per the language in revised guideline 8.c), PGE can and has provided such information previously. As we discussed in the Overview above, detailed information with project identifiers was provided in response to an information request during OPUC review of our DSP Part 2. However, the language as drafted is overly broad in a way that could be interpreted to evolve the DSP into

[7] DSP Part 2, Appendix L Capital planning process, available at: https://assets.ctfassets.net/416ywc1laqmd/6U7A3J9XfwsN5bLON9wShu/a00f7ecdc67cfc42601845ef1c4340a6/DSP_Part_2_-_AppendixL.pdf

a pre-project prudence review, which Staff, and the Commission in the context of a Special Public meeting, have indicated is not the intent of this process.[8]

PGE recommends removing revised guideline 8.c) and is interested in further exploring this topic to seek alignment as to what reporting, transparency, and/or documentation measures can prove useful. These should balance the preliminary nature of solutions put forward in a DSP, the administrative workload of utility planning staff, and the collaborative nature of DSP processes. We hope this exploration can occur as part of this guidance update process, resulting in revised guidance language for 8.c). One area of opportunity may be for PGE to provide a view of the projects that appear in a GRC and the corresponding DSP reference, i.e., a cross-reference between GRC projects and projects that appeared in prior DSPs. Alternately, or in addition, PGE can offer regular check-ins with Staff explaining shifts in distribution planned projects to keep Staff up to date on changes and progress on execution.

9 Long-term Distribution System Plan

PGE's long-term plan (LTP) outlines, at a high-level, the capabilities that PGE requires in order to continue delivering on its mission – delivering reliable, safe power at a reasonable cost – while addressing the transformational forces faced by the electric utility sector – decarbonization, electrification and climate change. PGE's LTP provides a narrative of the outcomes we seek to achieve and the roadmaps to achieve those outcomes. The OPUC's revised guidelines call for more detail than is typically included in a long-term planning discussion. **PGE recommends changing revised guideline 9.b.ii.1)** to "*Narrative description of the actions in the long-term plan,*" **and removing 9.b.ii.2-6)**.

With respect to revised guideline 9.b.iii), we understand the OPUC's interest in establishing a "thru-line" between DSP proposed actions and GRC investment recovery. As discussed in the Overview and Near-term Plan sections above, **PGE proposes that revised guideline 9.b.iii) be removed** and, through this guideline revision process, we work together to develop a product that can help identify which rate case investments map back to DSP proposed actions.

[8] Special Public Meeting UM 2197 PGE Distribution System Plan, recording timestamp 55:30, available at: https://oregonpuc.granicus.com/player/clip/1113

Appendix A: Comment and Revised Guideline Crosswalk

This appendix provides a more concise crosswalk between Staff's revised guidelines and PGE's recommendations for those guidelines.

1. Process and timing

OPUC Revised Guideline	PGE Comments
a) Each electric utility[1] must file its next Plan on or before the following dates, or an alternative date designated by Commission order. Idaho Power: Month Day, Year Portland General Electric: Month Day, Year Pacific Power: Month Day, Year	We propose filing our DSP in the September/October timeframe on an ongoing basis.
b) The date and cadence of filing subsequent Plans will be set in the next Guideline revision process, or by Commission order.	We intend to continue with the present development of a DSP that we will submit in September/October 2024 and submit the next DSP in September/October 2026.
c) Each utility will present the results of the filing to the Commission at a public meeting.	No change
d) Upon filing, the Commission will set a procedural schedule under which interested parties will have the opportunity to provide comment and make recommendations on the filing.	No change
e) The Commission will generally consider comments and recommendations on a utility's filing at a public meeting three to five months after it is filed. The Commission will consider whether to accept the filing as meeting the objectives of these Guidelines. The Commission may provide	PGE proposes to incorporate the TE Plan and Multi-year Plan into the DSP over time.

OPUC Revised Guideline	PGE Comments
guidance on the development and content of future Plans.	
f) The Commission may provide the utility an opportunity to revise the filing before making its decision.	No change

2. Commission Action

OPUC Revised Guideline	PGE Comments
The Commission will consider whether to accept the filed Plan as meeting the objectives of these Guidelines. As used in this Guideline, "acceptance" means the Commission finds the Plan meets the criteria and requirements of these Guidelines. Acceptance does not constitute a determination on the prudence of any individual actions discussed in the Plan. A decision to not accept a Plan means that the Plan does not meet the criteria or requirements of the Guidelines.	No change

3. Community Engagement

OPUC Revised Guideline	PGE Comments
a) During Plan development a utility should host at least four stakeholder workshops prior to filing the utility's Plan.[2] These workshops should be held during Plan development, at a stage in which stakeholder engagement can influence the filed Plan. The workshops may include in-person meetings located in a community, and may include	No change

OPUC Revised Guideline	PGE Comments
presentation of the Plan outline, data and assumptions under consideration or challenges encountered, and the utility's approach to community engagement. During stakeholder workshops, a utility must invite community members to share their perspectives, relevant needs, challenges, and opportunities or novel solutions for the grid.	
b) To engage stakeholders and community on distribution system planning, a utility should leverage best practices, and lessons learned from engagement efforts from prior Plans, and other planning processes. A utility should also leverage ongoing community and stakeholder engagement processes, and integrate distribution system planning engagement to the full extent it is beneficial to do so. Ongoing processes may include but are not limited to Clean Energy Planning, regional or local-area planning exercises.	No change
c) During preparation and implementation of a DSP, a utility should document community and stakeholder comments and feedback and utility response, including comments and feedback that were heard but not implemented. This documentation should be included in the utility's Plan when filed.	No change
d) A utility should maintain a Community Engagement Plan, as developed in the Company's prior DSP. The Community Engagement Plan should describe actions the utility will implement in order to engage	No change

OPUC Revised Guideline	PGE Comments
community members and CBOs if it needs to develop and implement non- wire solutions to address grid needs, or if it needs to engage communities around implementing larger projects. Larger projects may exclude, for example, regular maintenance projects, or inspection projects. The Community Engagement Plan should include the activities described below. i) Proactively engage stakeholders regarding possible non-wire solutions or larger projects in impacted communities. Engagement of the local community may include in- person meetings located in the community; presentation of the project scope, timeline, rationale; discussion of proposed utility projects and the value and risks associated with options; and solicitation of public comment, particularly to understand community needs and opportunities. ii) Collaboratively develop and share datasets and metrics to guide community-centered planning of the possible non-wire solutions or larger projects. iii) The Plan should consider engagement of local governments and Tribal nations for input on possible non-wire solutions, larger projects, as well as input on other policies intersecting distribution system planning. These may include opportunities or interest in micro-grids and other resiliency planning, or local environmental and climate plans such as fleet-electrification and building-electrification efforts.	

OPUC Revised Guideline	PGE Comments
e) Utilities should aim to create a collaborative environment among all interested CBO partners and stakeholders.	No change

4. Current System Data and Assessment

OPUC Revised Guideline	PGE Comments
a) A description of any currently used system assessment practices (such as system reliability assessments, system asset health assessments, etc.) that are utilized in identifying grid needs and evaluating possible solutions, which may include: i) Method and tools used to develop the assessment ii) Forecasting time horizon(s) iii) Key performance metrics	PGE recommends removing guideline 4.a) as it is duplicative of the information that is requested in Grid Needs guideline 6.a).
b) A summary description and table of the utility's distribution system assets including: i) Asset classes ii) Number of assets in each class iii) Average age of assets in each class iv) Age range of assets in each class v) Life expectancy of assets in each class vi) Percentage of assets in each class at or beyond the end of expected life	PGE recommends a revision to the cadence of providing the data identified in revised guidelines 4.b), 4.c) and 4.d). The information provided in the Baseline data and system assessment are relatively static, i.e., the numbers and conditions do not change that much or that often.

OPUC Revised Guideline	PGE Comments
c) A discussion of distribution system monitoring and control capabilities including: i) Number of feeders ii) Number of substations iii) Monitoring and control technologies (such as SCADA, AMI, etc.) currently installed, and the percentage of substations, feeders, and other applicable equipment with each technology iv) A description of the monitoring and control capabilities (for example, percentage of system with each technology, resulting capacity, such as remote fault detection or power quality monitoring, and what time interval measurements are available)	PGE recommends a revision to the cadence of providing the data identified in revised guidelines 4.b), 4.c) and 4.d). The information provided in the Baseline data and system assessment are relatively static, i.e., the numbers and conditions do not change that much or that often.
d) A discussion of any advanced control and communication systems (for example: distribution management systems, distributed energy resources management systems, demand response management systems, outage management systems, field area networks, etc.). The discussion should include: i) a description of system visibility and capabilities ii) the percentage of system reached with each capability, the percentage of customers reached with each capability iii) any utility programs utilizing each capability	PGE recommends a revision to the cadence of providing the data identified in revised guidelines 4.b), 4.c) and 4.d). The information provided in the Baseline data and system assessment are relatively static, i.e., the numbers and conditions do not change that much or that often.

OPUC Revised Guideline	PGE Comments
e) Historical distribution system spending for the past five years, in each category: i) Age-related replacements and asset renewal ii) System expansion or upgrades for capacity iii) System expansion or upgrades for reliability and power quality iv) New customer projects v) Grid modernization projects vi) Metering vii) Preventative maintenance	PGE recommends that guideline 4.e) be modified to exclude the categories provided in subparts i) – vii) and utilities be allowed to report past expenditures in the categories that reflect their individual project and financial management practices. PGE also notes that, with the DSP being submitted every two years, much of the data provided will overlap with past and subsequent DSPs. PGE suggests that the language of this guideline be modified to provide the data from one DSP to the next, so there is no overlap.
f) Net Metering and Small Generator information: i) Total existing net metering facilities and small generator facilities interconnected to the distribution grid (or to the transmission system, as appropriate for small generator facilities) at time of filing, by feeder. (1) The total number of net metering facilities by resource type (2) The total estimated rated generating capacity of net metering facilities by resource type (3) The total number of small generator facilities by resource type (4) The total nameplate capacity of small generator facilities by resource type ii) The total number and nameplate capacity of queued net metering facilities and small generator facilities at time	No change

OPUC Revised Guideline	PGE Comments
of filing, by feeder, broken down by resource type	
g) Plans should include the utility's most recently filed Annual Reliability Report as an appendix to the Plan. i) Any descriptions of reliability challenges and opportunities in the Distribution System Plan should cross-reference underlying data and information contained in the Annual Reliability Report ii) Any proposed investments based in whole, or in part, on reliability improvements must demonstrate those improvements by cross-referencing underlying data and information contained in the Annual Reliability Report	PGE recommends that 4.g.i) and 4.g.ii) be removed from the guidelines as they are overly prescriptive
h) Summary progress report on activities included in the most recently filed DSP to clearly communicate advancement or completion of: i) Investments, expenditures, and activities from the Long-term Plan ii) Investments, expenditures, and activities from the Near-term Action Plan	No change
i) Data assembled for this requirement should be prepared in electronic format, and submitted to the Commission for public review	No change

5. Forecasting of Load Growth, DER Adoption, and EV Adoption

OPUC Revised Guideline	PGE Comments
a) Forecast of load growth by feeder including discussion of: i) Forecasting method and tools used to develop the forecast ii) Forecasting time horizon(s) iii) Data sources used to inform the forecast iv) The load forecast should include data, inputs, and assumptions from the Company's most recent IRP/CEP, which should be clearly listed in the DSP. Examples include but are not limited to: (1) System modeled scenarios decomposed to the distribution system (2) Discussion of how IRP/CEP forecasting is decomposed to, and reconciled with, geographic areas of the distribution system, and identification of those specific geographic areas. Examples of such areas may include transitional planning areas.	PGE recommends that the guidelines should reflect using the most up to date and accurate input assumptions available at the time, rather than pointing backwards to CEP/IRP inputs, data, and assumptions.
b) Forecast of DER adoption and EV adoption by feeder including discussion of: i) Forecasting method and tools used to develop the forecast ii) Forecasting time horizon(s) iii) Data sources used to inform the forecast iv) The forecast should include high/medium/low scenarios for both DER adoption and EV adoption v) The DER adoption and EV adoption forecasts should include data, inputs, and assumptions from the	PGE recommends that the guidelines should reflect using the most up to date and accurate input assumptions available at the time, rather than pointing backwards to CEP/IRP inputs, data, and assumptions.

OPUC Revised Guideline	PGE Comments
Company's most recent IRP/CEP, which should be clearly listed in the DSP. Examples include but are not limited to: (1) Community based renewable energy (CBRE) forecast, potential study, RFP, needs assessment, etc. (2) Small scale renewable (SSR) forecast, potential study, RFP, needs assessment, etc. vi) The methodology for geographical allocation is at the utility's discretion. The Commission may provide direction for subsequent Plans.	
c) If a utility does not complete forecasting for its entire distribution system and instead completes forecasting for a portion of its distribution system, it must state so clearly and: i) explain the reasons for completing the exercise for a portion of the system ii) describe for how much of the system the exercise was completed, in terms of customers, load, substation count, and feeder count iii) discuss whether and how the utility plans to complete the exercise in future DSPs	No change

6. Grid Needs

OPUC Revised Guideline	PGE Comments
a) Document processes used to assess grid adequacy and identify grid needs	No change
b) Discuss criteria, methods, and tools used to identify needs by asset class	PGE recommends removing "… by asset class" from guideline 6.b).
c) Discuss and identify anticipated grid needs, including the following: i) Renewal needs based on asset condition ii) Grid needs to address forecasted load growth, DER adoption, EV adoption iii) Grid needs to address customer needs such as new service, additional service, or service quality iv) Grid needs to address other relevant utility plans including (1) IRP/CEP (2) Wildfire Mitigation Plan, including but not limited to identified Increased risk, either in geographically targeted areas, or at a system-level (3) Transportation Electrification Plan (4) Geographically targeted efforts of any demand side programs/DER programs (5) Annual reliability reporting, and any related performance issues v) Timing of grid needs	PGE recommends that revised guideline 6.c) include language that recognizes this constraint, such as "c) Discuss and identify anticipated grid needs (to the extent such identification does not violate customer privacy or NERC/CIP protections)…".

OPUC Revised Guideline	PGE Comments
d) Provide a summary table of each identified grid need by asset class and specifying the timing of need. The summary table should aid Staff and stakeholders in finding a thru-line from grid needs reported in a DSP to investments seen in future general rate cases.	PGE recommends removing the "thru-line" language from revised guideline 6.d). The revised guideline language should be "d) Provide a summary table of each identified grid need ~~by asset class and~~ specifying the timing of need. ~~The summary table should aid Staff and stakeholders in finding a thru-line from grid needs reported in a DSP to investments seen in future general rate cases.~~"

7. Solution Identification

OPUC Revised Guideline	PGE Comments
Introductory text	PGE recommends modifying the introductory language for the Solution Identification revised guidelines as follows: "The utility should assess grid needs to determine ~~cost effective~~ solutions as follows:"
a) Document the process to identify the range of possible solutions to address grid needs and discuss how this process was applied to identify the proposed solutions in the Long-term and Near-term Plans	PGE recommends the following modifications to revised guideline 7.a): "a) Document the process to identify the range of possible solutions to address priority grid needs ~~and discuss how this process was applied to identify the proposed solutions in the Long- term and Near-term Plans~~"

OPUC Revised Guideline	PGE Comments
	This recommendation essentially reverts to the original guideline language.
b) First, the utility process should assess each identified grid need to identify opportunities for no or low-incremental cost grid solutions such as rebalancing distribution loading through switching and phase balancing, or other actions	PGE finds recommendation 7.b) to be duplicative of 7.a) in that, per PGE's standard practice, we consider all solutions that are appropriate to address the grid need in the timeline required. If the guideline is to remain, we recommend removing the word "First", as it suggests an order of operations that is not necessarily informed by our current practice.
c) Second, if a specific grid need cannot be addressed by b) the utility should identify both a traditional solution and screen the grid need for suitability of a non-wires solution, if the cost for the traditional solution is $1 million or more i) Determine the suitability of a non-wires solution based on the following screening criteria: (1) Grid need is not a redundant supply to a radial load; (2) Grid need is not a maintenance, asset condition, or safety need; (3) Grid need is not a stability or short circuit problems; or (4) Grid need must be addressed within two years ii) If a grid need is suitable for a non-wires solution and comparatively cost-effective to the traditional solution, then the utility should identify the proposed non-wires solution(s) program, pricing, and/or procurement.	PGE recommends removing revised guidelines 7.c) and 7.d) and turn the focus to PGE's Smart Grid Testbed (SGTB) to advance the development of the capabilities required to enable a cost effective, reliable NWS.
d) All identified utility traditional and non-wires solutions should be documented in the Long-term and Near-term Plans as appropriate.	PGE recommends removing revised guidelines 7.c) and 7.d) and turn the focus to PGE's Smart Grid Testbed (SGTB) to

OPUC Revised Guideline	PGE Comments
	advance the development of the capabilities required to enable a cost effective, reliable NWS.

8. Near-term Action Plan

OPUC Revised Guideline	PGE Comments
a) Action Plan: Provide a 5 year plan of the utility's proposed solutions to address identified grid needs. The Action Plan should include: i) Prioritized list of investments, expenditures, and activities ii) A discussion of each planned investment/expenditures/activity estimated to cost more than $2 million. Each discussion should include: (1) Project narrative including foundational assumptions and key barriers or constraints (including financial, technical, organizational) and mitigation plans (2) Timeframe (3) Investment/expenditure amount (4) Description of the criteria and methods the utility used to prioritize the investment/expenditure/ activity, including explicit consideration of how the investment/expenditure/activity advances State policies and goals and PUC objectives, including but not limited to: a) Reliability	PGE recommends modifying revised guideline 8a.ii) to reflect a higher threshold for providing additional project details. PGE suggests changing the threshold from $2M to $10M as >80% of all distribution spending can be captured, described and listed if the threshold is set at $10M (or ~25 out of 105 projects). PGE recommends that revised guideline 8a.ii (1) be revised as follows: "~~Project~~ *Narrative description of the actions included in the Action Plan* ~~including foundational assumptions and key barriers or constraints (including financial, technical, organizational) and mitigation plans~~" PGE recommends removing revised guideline 8.a.ii.4) as it is duplicative of the information provided in the Grid Needs and Solution Identification processes.

OPUC Revised Guideline	PGE Comments
b) Safety and security c) Customer benefits and promoting inclusion of underserved populations d) Optimized operation of the system e) Efficient integration of DERs When possible, the description should include quantification of the improvement in the goal. Should a planned investment/expenditure/activity advance a goal not included in (a)-(e), a utility should explain the rationale for the investment/expenditure/activity, and when possible, include quantitative outcomes. (5) Explanation of how the investment/expenditure/activity is coordinated with the utility's other planning processes (such as the most recent IRP/CEP, Wildfire Mitigation Plan, Transportation Electrification (TE) Plan, and DR/Flexible Load Plan). (6) Any proposed investments/expenditures which address a grid need previously identified as a non-wires solution opportunity by the non-wires solutions screen should be identified and include a summary of the range of possible alternatives analyzed, the analysis results, and discussion of why the non-wires solution was not selected. (7) Discussion of whether the proposed	PGE recommends removing revised guideline 8a.ii.(6) pursuant to the fact that we do not yet have the tools or processes to implement an NWS that relies on customer-sited resources

OPUC Revised Guideline	PGE Comments
investment/expenditure/activity interacts with non-distribution asset strategies, whether alternatives to distribution investment were considered, and if made, what impact does the proposed investment/expenditure/activity have on other network assets.	
b) Projected spending: Provide the projected cost and timeline by asset class to implement the Action Plan. Provide a description of anticipated requests for cost recovery.	PGE recommends removing “asset class” from revised guideline 8.b)
c) The Action Plan prioritized list (Guideline 8 a) i)) and discussions (Guideline 8 a) ii)), as well as the projected spending (Guideline 8 b)) should aid Staff and stakeholders in finding a thru- line from the Near-term Action Plan to investments seen in future general rate cases. Further, when pursuing recovery in a general rate case, utilities should prepare to provide materials assembled for the DSP filing as well as additional materials such as documentation of proposed and various alternative solutions considered, and a detailed accounting of the relative costs and benefits of the chosen and alternative solutions, such as engineering reports, feeder level details (such as customer types on the feeder; loading information), DER forecasts and EV adoption rates.	PGE recommends removing 8.c) and is interested in further exploring the topic in order to seek alignment as to what reporting, transparency, and/or documentation measures can prove useful while balancing the preliminary nature of solutions put forward in a DSP, the administrative workload of utility planning staff, and the collaborative nature of DSP processes.

9. Long-term Plan

OPUC Revised Guideline	PGE Comments
a) The utility's vision for the distribution system for the next 10 years, aligned with State policies and goals and PUC objectives, including but not limited to: i) Reliability ii) Safety and security iii) Customer benefits and promoting inclusion of underserved populations iv) Optimized operation of the system v) Efficient integration of DERs	No change
b) Roadmap of the utility's planned investments, expenditures, and activities to advance the distribution system vision, for a 10-year planning horizon. The roadmap should include: i) Prioritized list of long-term investments, expenditures, and activities ii) A discussion of each planned investment/expenditures/activity including: (1) Project narrative including foundational assumptions and key barriers or constraints (including financial, technical, organizational) and mitigation plans (2) Estimated timeframe (3) Estimated investment/expenditure (4) Description of the criteria and methods the utility used to prioritize the investment/expenditure/activity, including explicit consideration of how the investment/expenditure/activity advances policies/goals/objectives identified in a) i)-v).	The OPUC's revised guidelines call for more detail than is typically included in a long-term planning discussion. PGE recommends changing revised guideline 9.b.ii.1) to "Narrative description of the actions in the long-term plan". With respect to revised guideline 9.b.iii), PGE recommends removing this revised guideline and, through this guideline revision process, we work together to develop a product that can help identify which rate case investments map back to DSP proposed actions.

OPUC Revised Guideline	PGE Comments
When possible, the explanation should include quantification of the improvement in the goal.8 Should a planned investment/expenditure/activity advance a goal not included in a) i)-v), a utility should explain the rationale for the investment/expenditure/activity, and when possible, include quantitative outcomes. (5) Any connections to, and impacts on, Near-term Action Plan projects (6) Explanation of how the investment/expenditure/activity fits with the utility's other planning processes (such as the most recent IRP/CEP, Wildfire Mitigation Plan, Transportation Electrification (TE) Plan, and DR/Flexible Load Plan) including how the investment/expenditure/activity is coordinated with each planning process with respect to related inputs and outputs such as data sets and prices, and assumptions such as macro-economic policies and growth rates. iii) The Long-term Plan Roadmap prioritized list (Guideline 9 b) i)) and discussions (Guideline 9 b) ii)) should aid Staff and stakeholders in finding a thru-line from the Long- term Plan to investments seen in future general rate cases.	

ATTACHMENT C
to
JOINT UTILITIES' COMMENTS

(PacifiCorp's DSP Comments)

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May 31, 2024

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RE: **PacifiCorp Comments re Staff's Proposed Distribution System Planning Guideline Revisions**

Please find enclosed PacifiCorp's ("the Company") Comments with respect to Commission Staff's Proposed Distribution System Planning ("DSP") Guideline Revisions issued on April 26, 2024. The Company appreciates the opportunity to provide feedback and comment on the Proposed DSP Guideline Revisions and to work with Staff, stakeholders, and fellow utilities on this next phase of DSP Guideline refinement while continuing to execute on the action plan outlined in the Part 2 filing. The Company applauds Staff for creating an environment for collaboration and open discussion through the proceedings to date. It is in that spirit of collaboration that the Company submits its comments. The Company anticipates making its next DSP filing on or before March 31, 2026.

The Company believes it understands Staff's high-level goals and objectives regarding the revised guidelines and seeks to find common ground where possible. The Company therefore proposes engaging in a round of workshops, and additionally requests the ability to submit a second round of comments prior to presenting the revised guidelines to the Commission.

The Company's attached comments address specific revisions and line items in Staff's proposed DSP Guidelines that cause concern for the Company, along with associated recommendations. In the Company's review of the proposed revisions several areas of concern emerged:

(1) Thru-Line from DSP Guidelines to Future General Rate Cases, Direction of Company Decision Making re Investment for Distribution Assets, and Ten Year Going-Forward Projections

The Company is concerned that Staff's Proposed DSP Guideline Revisions express an intent that the DSP information provided by the Company link directly to future general rate cases and "lay the groundwork for rate recovery." The Company is also concerned that Staff's revised Guidelines appear to step well beyond offering "input" for the utility to consider in its processes and decision-making and move toward directing Company decisions and investments prior to implementation—moving toward de facto management of utility decisions. Examples of proposed Guideline revisions to this effect include:

- Staff Proposed DSP Guideline 6(d): "Provide a summary table of each identified grid need by asset class and specifying the timing of need. ***The summary table should aid***

Staff and stakeholders in finding a thru-line from grid needs reported in a DSP to investments seen in future general rate cases." (Emphasis added.)

- Staff Proposed DSP Guideline 7: "These Guidelines advance more holistic distribution system planning, calling for consideration of a wider range of potential solutions (for example increased system monitoring automation, expanded switching capability, distributed energy resources). ***The solutions identified should correspond to future general rate cases***." (Emphasis added.)

- Staff Proposed DSP Guideline 8(c): "The Action Plan prioritized list (Guideline 8 a) i)) and discussions (Guideline 8 a) ii)), as well as the projected spending (Guideline 8 b)) should aid Staff and stakeholders in finding a ***thru line from the Near-term Action Plan to investments seen in future general rate cases***. Further, ***when pursuing recovery in a general rate case, utilities should prepare to provide materials assembled for the DSP filing as well as additional materials*** such as documentation of proposed and various alternative solutions considered, and a detailed accounting of the relative costs and benefits of the chosen and alternative solutions, such as engineering reports, feeder level details (such as customer types on the feeder; loading information), DER forecasts and EV adoption rates." (Emphasis added.)

- Staff Proposed DSP Guideline 9(b)(iii): "The Long-term Plan Roadmap prioritized list (Guideline 9 b) i)) and discussions (Guideline 9 b) ii)) should aid Staff and stakeholders in ***finding a thru-line from the Long-term Plan to investments seen in future general rate cases***." (Emphasis added.)

Staff's April 26, 2024, Executive Summary to the Proposed DSP Guideline Revisions notes that Staff "seeks to focus the next round of plans on vetting core investment planning information to directly inform the rate recovery process." Staff further notes that the next round of plans will focus on a "thorough review of the Companies' proposed grid investments and operational plans to (1) allow participants to influence decisions prior to their implementation; and (2) lay the groundwork for rate recovery" that will "require the utilities to provide detailed and comprehensive information about planned operational budgets and system investments, along with a clear rationale for prioritizing these expenses to maintain, improve, or avoid investments in the grid." Staff continues by explaining that "[f]or large distribution projects Staff will continue to prioritize the DSP as the primary venue for utility accountability . . ." Staff's Executive Summary proposes that the "Guideline revisions . . . focus DSP on grid needs, expenditure decision making and prioritization, and proposed investments and expenditures."

The Company finds proposed guidelines that establish a "thru-line" between DSP submissions and future general rate cases to be problematic. The Company's concern is that the DSP Guideline process will function as a de facto preview of the Company's general rate cases, or as a "pre-prudence" or "dual prudence" inquiry. This does not align with how capital planning and investment function in the Company's normal operations or rate cases. That is, that capital investments only become subject to review once they are used and useful and filed for inclusion in rate base.[1] This concern is heightened in light of Section 9 of Staff's Proposed DSP Guideline revisions calling for "[t]he utility's vision for the distribution system for the next 10 years . . ." Distribution system planning and procurement, considered on a ten-year going-forward basis, involves a high degree of speculation, outside the Company's normal business planning methodology, and is susceptible to a variety of contingent factors outside of the Company's control (*e.g.*, shifting system needs, population changes, weather events, unplanned disturbances, etc.). These factors require a contemporaneous approach and flexibility to meet ever-evolving system demands. Staff's statement that "when pursuing recovery in a general rate case, utilities should prepare to provide materials assembled for the DSP filing" suggests that DSP proceedings could operate prescriptively, could bind the Company and, in effect, represent a "pre-prudence" or "dual prudence" inquiry.

The Company is also concerned that the revised DSP Guidelines appear to directly influence Company decision making regarding proposed distribution investments and expenditures. Directing Company investment decisions in a planning proceeding is problematic on a number of levels. Most importantly, the utility is a private entity providing a service that has to manage both its operations and financial health to provide that service. Failure to address both aspects has consequences. The Company believes that directing utility action is beyond the scope of this DSP process, could put the utility at financial risk, and could result in unnecessarily higher rates. From the Company's perspective, Commission direction to plan or invest in a certain manner would have to be associated with preapproval of any assets because the Commission would usurp the utility's ability to manage its finances. Such direction, even in the context of a general rate case, is contrary to established precedent.[2] *See, e.g.*, proposed guidelines 8(a)(ii)(4) and 9(a).

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[1] *See, e.g.*, *In re Nw. Nat. Gas Co.*, Docket No. UM 125, UP 38, Order No. 87-1044 at 536–37 (Oct. 5, 1987) ("Will the Public Utility Commission of Oregon in these dockets undertake to render a decision in advance of construction with respect to the prudence of Northwest Natural Gas Company to develop an underground natural gas storage facility[?] . . . The answer to this question is 'no' . . . Decisions of this type by utility management are reviewed in the context of applications to recover costs of plant which is in service, not projects in the planning stage. Any decision by a utility to undertake a construction project involves some risk that the project, if completed, will not meet expectations. However, that risk and the risk of noncompletion is upon the company alone. The Commission only has authority to determine whether the plant is used and useful when a request is made to reflect its costs in utility rates."); *see also In re Application of Nw. Nat. Gas Co. for A Gen. Rate Revision*, Docket No. UG 132, Order No. 99-697 at 52 (Nov. 12, 1999) ("Prudence in planning and constructing a plant is relevant for determining the valuation of the facility once placed in rate base.").

[2] *See, e.g.*, *City of Portland Complainant*, Docket No. UM 1262, Order No. 06-636 at 6 (Nov. 17, 2006) ("The Oregon Supreme Court observed that the Commission's role is not to manage the utility, but to consider the utility's management and its effect on rates. 'The determination of what is reasonable in conducting the business of the utility is the primary responsibility of management. If the commission is empowered to prescribe the terms of contracts and the practices of utilities and thus substitute its judgment as to what is reasonable for that of management, it is empowered to undertake the management of all utilities subject to its jurisdiction. It has been repeatedly held, however, that the commission does not have such power.'") (*citing Pac. Tel. & Tel. Co. v. Flagg*, 189 Or. 370, 395–96 (1950)); *see also In re Pacificorp, DBA Pac. Power Request for A Gen. Rate Revision*, Docket No. UE 246, Order No. 12 493 at 25 (Dec. 20, 2012) ("[N]or is it appropriate for the [commission] to merely substitute its best judgment for the judgments made by the company's managers. The company's conduct should be judged by asking whether the conduct was reasonable at the time, under all circumstances, considering that the company had to solve its problems prospectively . . .").

(2) Expansion of Scope under Proposed DSP Guideline Revisions

Several of Staff's Proposed DSP Guideline Revisions would expand the scope of the DSP process far beyond distribution-focused assessments and stray into other areas of the Company's management. For example, proposed guideline 6(c)(iv)(1)-(5) states that a utility's DSP should "(c) Discuss and identify anticipated grid needs, including the following: . . . (iv) Grid needs to address other relevant utility plans including (1) IRP/CEP; (2) Wildfire Mitigation Plan, including but not limited to identified increased risk, either in geographically targeted areas, or at a system-level; (3) Transportation Electrification Plan; (4) Geographically targeted efforts of any demand side programs/DER programs; and (5) Annual reliability reporting, and any related performance issues." As revised, this proposed guideline would bring each of these broad areas of Company operation under the purview of the DSP process. Other similar examples of revised guidelines that would greatly expand the scope of the DSP process include proposed guidelines 4(g), 8(a)(ii)(5), and 9(b)(ii)(6).

(3) Increased Granularity and Detail of Data Requested under Proposed DSP Guideline Revisions, Areas of Incongruity between Guidelines and Company Data, and Confidentiality

Certain of Staff's Proposed DSP Guideline Revisions substantially increase the granularity and level of detail to be included in DSP beyond what was provided in Part 2 and beyond what is reasonably feasible for the Company to provide. For example, proposed guidelines 4(e)(i)-(vii) seek "historical distribution system spending for the past five years" for seven categories of spending that were initially requested and provided by the Company in Part 1, but that proved to be extraordinarily burdensome to derive (the requests sought data outside of the Company's existing accounting structure). Following discussions between Company representatives and OPUC Staff held on December 2, 2022, it was agreed that the Company would provide information based on its existing accounting structures and categorization in its Part 2 submissions. *See* PacifiCorp's Responses to OPUC Data Requests 8-11, Docket UM 2198, dated December 12, 2022. For example, OPUC Data Request No. 8(c) sought project level spending data "for any projects begun in prior years, for each of the years 2023, 2024, 2025, and 2026." In response to this request the Company explained that:

> "[T]he forecast was not constructed using project level details. As such, large portions of the forecast expenditures are contained in Program level budgets within the forecast horizon. Specific projects will be managed from these Program budgets, but project level details were not used in the development of Figure 53. Larger projects that are not part of a Program may have a specific line item in the forecast. In such instances, the project expenditures have been identified by category for projects started before 2022 and for projects that started after 2021."

Proposed guidelines 8(a) (Near-Term Plan) and 9(a) (Long-Term Plan) seek a similar level of detail and categorization to proposed guidelines 4(e)(i)-(vii) on a going-forward basis. Particularly in the context of the 10-year going-forward nature of the Long-Term Plan, project-level and even program-level cost projection figures will be subject to significant change as operational needs and contingencies evolve. Moving forward, the Company proposes providing a level of detail and categorization like what was provided in response to OPUC Data Request No. 8 for its Part 2 filing.

In other areas, Staff's proposed Guideline revisions seek data that does not align with categories of data that the Company maintains in its normal course of business. For example, revised guideline 6(b) (regarding grid needs) asks the Company to "Discuss criteria, methods, and tools used to identify needs by asset class." Similarly, revised guideline 6(d) (also regarding grid needs) asks the Company to "Provide a summary table of each identified grid need by asset class and specifying the timing of need." However, the Company does not in its normal operations identify grid needs by asset class. Another example of incongruity between the revised guidelines and data categorization maintained by the Company is found in revised guideline 8(b) (regarding the Near-Term Action Plan). This guideline seeks "Projected spending: Provide the projected cost and timeline by asset class to implement the Action Plan. Provide a description of anticipated requests for cost recovery." However, the Company does not make cost and timeline projections by asset class. As was done for its Part 2 filing, the Company hopes to work collaboratively with Staff to find solutions to these areas of data incongruity that are acceptable for Staff and feasible for the Company.

Lastly, the Company continues to have concerns regarding the confidentiality, privacy, and security of personally identifiable customer information as well as PacifiCorp's sensitive, confidential, and/or proprietary business information, particularly in the context of project-level data. In the above-referenced discussions between OPUC Staff and the Company in December 2022, Staff clarified that the Company would provide responses to information requests in a manner that did not contain confidential or protected information for ease of sharing. Moving forward, the Company would like to continue with this understanding in place as it provides data in response to the revised guidelines (*e.g.*, through performing redactions, removing certain sets of sensitive and/or confidential information as needed, etc.).

(4) Load Forecasting: Staff Recommends OPUC and Stakeholders Conduct Workshops re Forecasting Methodology & Approach in Advance of Adopting New Requirements

Staff's proposed guideline 5 generally seeks to "require a utility to document in its Plan current utility load forecasting processes for distribution service and forecasting processes for DER adoption and EV adoption." The Company believes it would be most productive, with respect to this revised guideline, for the OPUC to organize a workshop to discuss forecasting methodology and/or approaches before adopting any new requirements. Generally speaking, circuit-level forecasts reflect macro-level assumptions and trends from IRP, CEP, and TE plans. However, circuit forecasts are focused on local conditions, circuits characteristics, and constraints. Circuit level forecasts will therefore reflect the conditions that place the greatest demand on the local circuit. That timing and set of conditions is very unlikely to correspond to peak conditions contained in IRP or system-level forecasts. The Company believes a workshop could best address these issues and how the guidelines could be revised to better reflect this operational reality.

(5) Non-Wires Analysis Criteria in the Context of Near-Term and Long-Term Plans: Projections Subject to Change

Revised guideline 7 seeks, in part, that "[a]ll identified utility traditional and non-wires solutions . . . be documented in the Long-term and Near-term Plans as appropriate." Non-wires solutions reflect new and evolving technology solutions. The Company is not certain about the successful nature of individual potential non-wires solutions. As such, a recitation of plans involving non-wires solutions, particularly in the context of the near-term and long-term plans on a going forward basis (and specifically in the context of any thru-line to rate recovery) would be subject to a significant level of change and evolution. This is a challenge the Company would like an opportunity to clarify with OPUC Staff in advance of any requirement that non-wires solutions be integrated into the near-term and short-term planning methodology.

In closing, the Company fully supports and anticipates a continued open and collaborative approach to the DSP planning and guideline process, and shares the views expressed by the OPUC Commissioners and PGE (during the Special Public Meeting held on February 28, 2024) that: DSP planning should stay at an appropriate level of detail to support the evolution of and foundational improvements to DSP; and (2) that refinements to DSP guidelines should encourage the core values of innovation, open and frank discussion, and pragmatism. To that end, the Company believes workshops are needed to collaborate on a revised set of guidelines addressing the Company's concerns as expressed in the attached line-item comments. The Company looks forward to continued discussions with all stakeholders regarding innovative and pragmatic solutions to DSP issues.

If you have any questions, please call me at (503) 813-5817 (desk) or (503) 730-6276 (cell).

Sincerely,

/s/ *Daniel J. Teimouri*
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OPUC Staff Proposed DSP Guideline Revisions (4/29/2024)

ID	Section/Requirement	Comment/Notes
1	**Process and Timing**	
	The following development and review process will guide the utility filing of a Distribution System Plan (Plan) for a utility's service territory in Oregon.	
a)	Each electric utility1 must file its next Plan on or before the following dates, or an alternative date designated by Commission order: Idaho Power: Month, Day, Year Portland General Electric: Month, Day, Year Pacific Power: Month, Day, Year	PacifiCorp (The Company) intends to file it's next plan on or before March 31st, 2026.
b)	The date and cadence of filing subsequent Plans will be set in the next Guideline revision process, or by Commission order.	
c)	Each utility will present the results of the filing to the Commission at a public meeting.	
d)	Upon filing, the Commission will set a procedural schedule under which interested parties will have the opportunity to provide comment and make recommendations on the filing.	
e)	The Commission will generally consider comments and recommendations on a utility's filing at a public meeting three to five months after it is filed. The Commission will consider whether to accept the filing as meeting the objectives of these Guidelines. The Commission may provide guidance on the development and content of future Plans.	
f)	The Commission may provide the utility an opportunity to revise the filing before making its decision.	
2	**Commission Action**	
	The Commission will consider whether to accept the filed Plan as meeting the objectives of these Guidelines. As used in this Guideline, "acceptance" means the Commission finds the Plan meets the criteria and requirements of these Guidelines. Acceptance does not constitute a determination on the prudence of any individual actions discussed in the Plan. A decision to not accept a Plan means that the Plan does not meet the criteria or requirements of the Guidelines.	
3	**Community Engagement**	
	Intro not included in excel version - see PDF or Word version for introduction language	
	Specific Community Engagement Requirements for utilities include:	

ID	Section/Requirement	Comment/Notes
a)	During Plan development a utility should host at least four stakeholder workshops prior to filing the utility's Plan.2 These workshops should be held during Plan development, at a stage in which stakeholder engagement can influence the filed Plan. The workshops may include in- person meetings located in a community, and may include presentation of the Plan outline, data and assumptions under consideration or challenges encountered, and the utility's approach to community engagement. During stakeholder workshops, a utility must invite community members to share their perspectives, relevant needs, challenges, and opportunities or novel solutions for the grid.	
b)	To engage stakeholders and community on distribution system planning, a utility should leverage best practices, and lessons learned from engagement efforts from prior Plans, and other planning processes. A utility should also leverage ongoing community and stakeholder engagement processes, and integrate distribution system planning engagement to the full extent it is beneficial to do so. Ongoing processes may include but are not limited to Clean Energy Planning, regional or local-area planning exercises.	
c)	During preparation and implementation of a DSP, a utility should document community and stakeholder comments and feedback and utility response, including comments and feedback that were heard but not implemented. This documentation should be included in the utility's Plan when filed.	
d)	A utility should maintain a Community Engagement Plan, as developed in the Company's prior DSP. The Community Engagement Plan should describe actions the utility will implement in order to engage community members and CBOs if it needs to develop and implement non- wire solutions to address grid needs, or if it needs to engage communities around implementing larger projects. Larger projects may exclude, for example, regular maintenance projects, or inspection projects. The Community Engagement Plan should include the activities described below.	The Company has consolidated the community engagement plan under the Clean Energy Plan (CEP) and Community Benefits and Impacts Advisory Group (CBIAG). DSP actively participates in the community engagement under thse initiatives. DSP continues to conduct local engagement as outlined in the DSP Near-Term Action Plan and when necessary to collaborate with communities on potential non-wires solutions.
i)	Proactively engage stakeholders regarding possible non-wire solutions or larger projects in impacted communities. Engagement of the local community may include in-person meetings located in the community; presentation of the project scope, timeline, rationale; discussion of proposed utility projects and the value and risks associated with options; and solicitation of public comment, particularly to understand community needs and opportunities.	
ii)	Collaboratively develop and share *datasets and metrics* to guide community-centered planning of the possible non-wire solutions or larger projects.	*Recommend strike "datasets and metrics" and replace with "information."*
iii)	The Plan should consider engagement of local governments and Tribal nations for input on possible non-wire solutions, larger projects, as well as input on other policies intersecting distribution system planning. *These may include opportunities or interest in micro-grids and other resiliency planning, or local environmental and climate plans such as fleet-electrification and building-electrification efforts* .	*Recommend striking the last sentence of the requirement that includes "may" items.*

ID	Section/Requirement	Comment/Notes
e)	Utilities should aim to create a collaborative environment among all interested CBO partners and stakeholders.	

4	**Current System Data and Assessment**	
	To foster transparency and enable effective decision-making, Distribution System Plans should provide a fundamental understanding of the current physical status of the utility distribution systems and equipment, progress of investment in those systems, the level of distributed energy resources (DERs) currently integrated into those systems,3 and management and monitoring practices of those systems.	
	The Utility should provide at a minimum:	
a)	A description of any currently used system assessment practices (such as system reliability assessments, system asset health assessments, etc.) that are utilized in identifying grid needs and evaluating possible solutions, which may include:	
i)	Method and tools used to develop the assessment	
ii)	Forecasting time horizon(s)	
iii)	Key performance metrics	
b)	A summary description and table of the utility's distribution system assets including:	
i)	Asset classes	
ii)	Number of assets in each class	
iii)	Average age of assets in each class	
iv)	Age range of assets in each class	
v)	Life expectancy of assets in each class	
vi)	Percentage of assets in each class at or beyond the end of expected life	
c)	A discussion of distribution system monitoring and control capabilities including:	
i)	Number of feeders	
ii)	Number of substations	
iii)	Monitoring and control technologies (such as SCADA, AMI, etc.) currently installed, and the percentage of substations, feeders, and other applicable equipment with each technology	
iv)	A description of the monitoring and control capabilities (for example, percentage of system with each technology, resulting capacity, such as remote fault detection or power quality monitoring, and what time interval measurements are available)	
d)	A discussion of any advanced control and communication systems (for example: distribution management systems, distributed energy resources management systems, demand response management systems, outage management systems, field area networks, etc.). The discussion should include:	
i)	a description of system visibility and capabilities	

ID	Section/Requirement	Comment/Notes
ii)	the percentage of system reached with each capability, the percentage of customers reached with each capability	
iii)	any utility programs utilizing each capability	
e)	Historical distribution system spending for the past five years, in each category:	The Company proposes to strike the categories outlined below and to report based on the categories that were provided in the PacifiCorp DSP Part 2 filing and subsequent Data Responses related to investment categories. Please refer to concern (3) in the attached letter regarding communications with staff for prior data requests that are related to this requirement.
i)	Age-related replacements and asset renewal	See above
ii)	System expansion or upgrades for capacity	See above
iii)	System expansion or upgrades for reliability and power quality	See above
iv)	New customer projects	See above
v)	Grid modernization projects	See above
vi)	Metering	See above
vii)	Preventative maintenance	See above
f)	Net Metering and Small Generator information:	
i)	Total existing net metering facilities and small generator facilities interconnected to the distribution grid (or to the transmission system, as appropriate for small generator facilities) at time of filing, by feeder.	
-1	The total number of net metering facilities by resource type	
-2	The total estimated rated generating capacity of net metering facilities by resource type	
-3	The total number of small generator facilities by resource type	
-4	The total nameplate capacity of small generator facilities by resource type	
ii)	The total number and nameplate capacity of queued net metering facilities and small generator facilities at time of filing, by feeder, broken down by resource type	
g)	Plans should include the utility's most recently filed Annual Reliability Report as an appendix to the Plan.	
i)	Any descriptions of reliability challenges and opportunities in the Distribution System Plan should cross-reference underlying data and information contained in the Annual Reliability Report	The Company proposes Commission Staff organize workshops to collaborate on a revised set of requirements for 4(g)(i-ii) to further define the intent and scope. See concern (2) in the attached letter regarding expansion of scope.
ii)	Any proposed investments based in whole, or in part, on reliability improvements must demonstrate those improvements by cross-referencing underlying data and information contained in the Annual Reliability Report	See above
h)	Summary progress report on activities included in the most recently filed DSP to clearly communicate advancement or completion of:	
i)	Investments, expenditures, and activities from the Long-term Plan	
ii)	Investments, expenditures, and activities from the Near-term Action Plan	
i)	Data assembled for this requirement should be prepared in electronic format, and submitted to the Commission for public review	The Company has concerns regarding the level of detail and confidentiality being requested by this requirement. Please refer to concern (3) in the attached letter. The Company proposes striking this requirement until workshops take place to further define parameters of the data being requested.

ID	Section/Requirement	Comment/Notes
5	**Forecasting of Load Growth, DER Adoption, and EV Adoption**	
	(Initial two sentences of this text excluded from this section for brevity) The updated requirements aim to improve the accuracy and granularity of forecasting. This in turn is intended to improve the accuracy and granularity of existing and anticipated constraints on the distribution system revealed in the engineering analysis to identify Grid Needs.	
	The Guidelines require a utility to document in its Plan current utility load forecasting processes for distribution service, and forecasting processes for DER adoption and EV adoption as follows:	The Company proposes to strike this entire section until joint workshops can be convened to collaborate on a revised set of requirements for this section. Please refer to concern (4) in the attached letter.
a)	Forecast of load growth by feeder including discussion of:	See above
i)	Forecasting method and tools used to develop the forecast	See above
ii)	Forecasting time horizon(s)	See above
iii)	Data sources used to inform the forecast	See above
iv)	The load forecast should include data, inputs, and assumptions from the Company's most recent IRP/CEP, which should be clearly listed in the DSP. Examples include but are not limited to:	See above
-1	System modeled scenarios decomposed to the distribution system	See above
-2	Discussion of how IRP/CEP forecasting is decomposed to, and reconciled with, geographic areas of the distribution system, and identification of those specific geographic areas. Examples of such areas may include transitional planning areas.	See above
b)	Forecast of DER adoption and EV adoption by feeder including discussion of:	See above
i)	Forecasting method and tools used to develop the forecast	See above
ii)	Forecasting time horizon(s)	See above
iii)	Data sources used to inform the forecast	See above
iv)	The forecast should include high/medium/low scenarios for both DER adoption and EV adoption	See above
v)	The DER adoption and EV adoption forecasts should include data, inputs, and assumptions from the Company's most recent IRP/CEP, which should be clearly listed in the DSP. Examples include but are not limited to:	See above
-1	Community based renewable energy (CBRE) forecast, potential study, RFP, needs assessment, etc.	See above
-2	Small scale renewable (SSR) forecast, potential study, RFP, needs assessment, etc.	See above
vi)	The methodology for geographical allocation is at the utility's discretion. The Commission may provide direction for subsequent Plans.	See above
c)	If a utility does not complete forecasting for its entire distribution system and instead completes forecasting for a portion of its distribution system, it must state so clearly and:	See above
i)	explain the reasons for completing the exercise for a portion of the system	See above
ii)	describe for how much of the system the exercise was completed, in terms of customers, load, substation count, and feeder count	See above
iii)	discuss whether and how the utility plans to complete the exercise in future DSPs	See above

ID	Section/Requirement	Comment/Notes
6	**Grid Needs**	
	Grid needs identification compares the current capabilities of a distribution system and the demands on that system to infer its future needs. At its core, a grid needs identification answers the question of what technical requirements must be addressed to ensure a safe, reliable and resilient system that provides adequate power quality to the customers it serves. Adding to this core, grid needs identification should include constraints related to forecast of customer and front-of-the-meter DER. Additionally, the social and economic needs of the communities that depend on distribution systems, and the contributions they can make to strengthen it should be addressed. Grid needs identification should be comprehensive and inclusive, identifying the biggest drivers and trends behind needed investments and operational budgets.	The Company proposes to strike the highlighted text unless Staff can provide clarification that can be reviewed prior to presentation to the Commision.
	A utility's Distribution System Plan should:	
a)	Document processes used to assess grid adequacy and identify grid needs	
b)	Discuss criteria, methods, and tools used to identify needs by asset class	The Company proposes to strike this requirement. See concern (3) in the attached letter regarding categorization by asset class.
c)	Discuss and identify anticipated grid needs, including the following:	
i)	Renewal needs based on asset condition	
ii)	Grid needs to address forecasted load growth, DER adoption, EV adoption	
iii)	Grid needs to address customer needs such as new service, additional service, or service quality	
iv)	Grid needs to address other relevant utility plans including	The Company proposes to strike this entire section until joint workshops can be convened to collaborate on a revised set of requirements for this section. See concern (2) in the attached letter.
-1	IRP/CEP	See above
-2	Wildfire Mitigation Plan, including but not limited to identified Increased risk, either in geographically targeted areas, or at a system-level	See above
-3	Transportation Electrification Plan	See above
-4	Geographically targeted efforts of any demand side programs/DER programs	See above
-5	Annual reliability reporting, and any related performance issues	See above
v)	Timing of grid needs	
d)	Provide a summary table of each identified grid need by asset class and specifying the timing of need. The summary table should aid Staff and stakeholders in finding a thru-line from grid needs reported in a DSP to investments seen in future general rate cases.	The Company proposes to strike this requirement. The Company does not track grid needs by asset class. See concerns (1) and (3) in the attached letter regarding concerns with the DSP serving as a thru-line to the GRC and the level of detail requested.
7	**Solution Identification**	

ID	Section/Requirement	Comment/Notes
	Solution identification proposes the equipment, technology or program(s) the utility will advance to meet identified grid needs. Previously, a Distribution System Plan would rely on traditional hardware solutions (such as substation upgrades, reconductoring, and additional transformer deployment). These Guidelines advance more holistic distribution system planning, calling for consideration of a wider range of potential solutions (for example increased system monitoring automation, expanded switching capability, distributed energy resources). The solutions identified should correspond to future general rate cases.	The Company proposes to strike this entire section until joint workshops can be convened to collaborate on a revised set of requirements for this section. In the attached letter, please refer to concern (1) regarding concerns with DSP serving as a thru-line to the GRC and concern (5) regarding non-wires solution criteria.
	The utility should assess grid needs to determine **cost effective** solutions as follows:	See above
a)	Document the process to identify the range of possible solutions to address grid needs and discuss how this process was applied to identify the proposed solutions in the Long-term and Near-term Plans	See above
b)	First, the utility process should assess each identified grid need to identify opportunities for no or low-incremental cost grid solutions such as rebalancing distribution loading through switching and phase balancing, or other actions	See above
c)	Second, if a specific grid need cannot be addressed by b) the utility should identify both a traditional solution and screen the grid need for suitability of a non-wires solution, if the cost for the traditional solution is $1 million or more	See above
i)	Determine the suitability of a non-wires solution based on the following screening criteria:	See above
-1	Grid need is not a redundant supply to a radial load;	See above
-2	Grid need is not a maintenance, asset condition, or safety need;	See above
-3	Grid need is not a stability or short circuit problems; or	See above
-4	Grid need must be addressed within two years	See above
ii)	If a grid need is suitable for a non-wires solution and comparatively cost-effective to the traditional solution, then the utility should identify the proposed non-wires solution(s) program, pricing, and/or procurement.	See above
d)	All identified utility traditional and non-wires solutions should be documented in the Long-term and Near-term Plans as appropriate.	See above
8	**Near Term Action Plan**	
	In this section of the Plan, a utility should present the utility's proposed solutions to address near-term grid needs. Specific requirements include:	
a)	Action Plan: Provide a 5 year plan of the utility's proposed solutions to address identified grid needs. The Action Plan should include:	The Company proposes to strike this entire section until joint workshops can be convened to collaborate on a revised set of requirements for this section. Please see concern (3) in the attached letter regarding increased granularity and detail being requested.
i)	Prioritized list of investments, expenditures, and activities	See above
ii)	A discussion of each planned investment/expenditures/activity estimated to cost more than $2 million. Each discussion should include:	See above

ID	Section/Requirement	Comment/Notes
-1	Project narrative including foundational assumptions and key barriers or constraints (including financial, technical, organizational) and mitigation plans	See above
-2	Timeframe	See above
-3	Investment/expenditure amount	See above
-4	Description of the criteria and methods the utility used to prioritize the investment/expenditure/activity, including explicit consideration of how the investment/expenditure/activity advances **State policies and goals and PUC objectives**, including but not limited to:5	See above
(a)	Reliability	See above
(b)	Safety and security	See above
(c)	Customer benefits and promoting inclusion of underserved populations	See above
(d)	Optimized operation of the system	See above
(e)	Efficient integration of DERs	See above
	When possible, the description should include quantification of the improvement in the goal.6 Should a planned investment/expenditure/activity advance a goal not included in (a)-(e), a utility should explain the rationale for the investment/expenditure/activity, and when possible, include quantitative outcomes.	See above
-5	Explanation of how the investment/expenditure/activity is coordinated with the utility's other planning processes (such as the most recent IRP/CEP, Wildfire Mitigation Plan, Transportation Electrification (TE) Plan, and DR/Flexible Load Plan).	See above. Please refer to concern (2) in the attached letter.
-6	Any proposed investments/expenditures which address a grid need previously identified as a non-wires solution opportunity by the non-wires solutions screen should be identified and include a summary of the range of possible alternatives analyzed, the analysis results, and discussion of why the non-wires solution was not selected.	See above
-7	Discussion of whether the proposed investment/expenditure/activity interacts with non-distribution asset strategies, whether alternatives to distribution investment were considered, and if made, what impact does the proposed investment/expenditure/activity have on other network assets.	See above
b)	Projected spending: Provide the projected cost and timeline by asset class to implement the Action Plan. Provide a description of anticipated requests for cost recovery.	See above

ID	Section/Requirement	Comment/Notes
c)	The Action Plan prioritized list (Guideline 8 a) i)) and discussions (Guideline 8 a) ii)), as well as the projected spending (Guideline 8 b)) should aid Staff and stakeholders in finding a thru- line from the Near-term Action Plan to investments seen in future general rate cases. Further, when pursuing recovery in a general rate case, utilities should prepare to provide materials assembled for the DSP filing as well as additional materials such as documentation of proposed and various alternative solutions considered, and a detailed accounting of the relative costs and benefits of the chosen and alternative solutions, such as engineering reports, feeder level details (such as customer types on the feeder; loading information), DER forecasts and EV adoption rates.	Please see concern (1) in the attached letter, regarding DSP serving as a thru-line to the GRC.
9	**Long Term Plan**	
	This section of the Distribution System Plan consists of the utility's long-term investment plan. This section of the plan should include:	
a)	The utility's vision for the distribution system for the next 10 years, aligned with State policies and goals and PUC objectives, including but not limited to:7	The Company proposes to strike this entire section until joint workshops can be convened to collaborate on a revised set of requirements for this section. Please see concern (3) in the attached letter regarding increased granularity and detail being requested.
i)	Reliability	See above
ii)	Safety and security	See above
iii)	Customer benefits and promoting inclusion of underserved populations	See above
iv)	Optimized operation of the system	See above
v)	Efficient integration of DERs	See above
b)	Roadmap of the utility's planned investments, expenditures, and activities to advance the distribution system vision, for a 10-year planning horizon. The roadmap should include:	See above
i)	Prioritized list of long-term investments, expenditures, and activities	See above
ii)	A discussion of each planned investment/expenditures/activity including:	See above
-1	Project narrative including foundational assumptions and key barriers or constraints (including financial, technical, organizational) and mitigation plans	See above
-2	Estimated timeframe	See above
-3	Estimated investment/expenditure	See above
-4	Description of the criteria and methods the utility used to prioritize the investment/expenditure/activity, including explicit consideration of how the investment/expenditure/activity advances policies/goals/objectives identified in a) i)-v). When possible, the explanation should include quantification of the improvement in the goal.8 Should a planned investment/expenditure/activity advance a goal not included in a) i)-v), a utility should explain the rationale for the investment/expenditure/activity, and when possible, include quantitative outcomes.	See above
-5	Any connections to, and impacts on, Near-term Action Plan projects	See above

ID	Section/Requirement	Comment/Notes
-6	Explanation of how the investment/expenditure/activity fits with the utility's other planning processes (such as the most recent IRP/CEP, Wildfire Mitigation Plan, Transportation Electrification (TE) Plan, and DR/Flexible Load Plan) including how the investment/expenditure/activity is coordinated with each planning process with respect to related inputs and outputs such as data sets and prices, and assumptions such as macro-economic policies and growth rates.	See above. Please refer to concern (2) in the attached letter.
iii)	The Long-term Plan Roadmap prioritized list (Guideline 9 b) i)) and discussions (Guideline 9 b) ii)) should aid Staff and stakeholders in finding a thru-line from the Long- term Plan to investments seen in future general rate cases.	Please see concern (1) in the attached letter regarding DSP serving as a thru-line to the GRC.