Portland General Electric
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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

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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**

[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
- ✓ Transformer
- ✓ Circuit breaker
- ✓ Relay system
- ✓ SCADA system
- ✓ Switch

Distribution assets
- ✓ UG cable
- ✓ Line transformer
- ✓ Recloser
- ✓ Regulator
- ✓ Switch
- ✓ Structures

Geographic risk
- ✓ Vegetation/weather risk
- ✓ Wildfire risk
- ✓ Animal risk
- ✓ Public risk

Business case tools
- ✓ Risk register
- ✓ Integrated planning tool

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

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[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.	