ORDER NO. 25-431

ENTERED Oct. 29, 2025

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2362

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2024 Distribution System Plan.	ORDER

DISPOSITION: STAFF'S RECOMMENDATION ADOPTED

At its public meeting on October 28, 2025, the Public Utility Commission of Oregon adopted Staff's recommendation in this matter. The Staff Report with the recommendation is attached as Appendix A.

BY THE COMMISSION:

Alison Lackey
Chief Administrative Law Judge

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Circuit Court for Marion County in compliance with ORS 183.484.

ITEM NO. RA1

PUBLIC UTILITY COMMISSION OF OREGON
REDACTED STAFF REPORT
PUBLIC MEETING DATE: October 28, 2025

REGULAR X CONSENT ____ EFFECTIVE DATE N/A

DATE: October 21, 2025

TO: Public Utility Commission

FROM: Nick Sayen and Rebecca Feuerlicht

THROUGH: Caroline Moore and Sarah Hall **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. UM 2362)
2024 Distribution System Plan.

STAFF RECOMMENDATION:

Accept Portland General Electric's 2024 Distribution System Plan and direct the Company to file an Interim Update by December 1, 2026.

DISCUSSION:

Issue

Whether to accept Portland General Electric's (PGE or Company) 2024 Distribution System Plan (DSP or Plan), and reschedule the Company's Interim Update from December 18, 2025 to December 1, 2026.

Applicable Rule or Law

ORS 756.040 describes the general powers of the Commission to supervise and regulate every public utility, and to do all things necessary and convenient in the exercise of that authority.

Under ORS 756.105(1), "Every public utility or telecommunications utility shall furnish to the Public Utility Commission all information required by the commission to carry into effect the provisions of ORS chapters 756, 757, 758 and 759."

In Order No. 19-104, the Commission opened Docket No. UM 2005 to "develop a transparent, robust, holistic regulatory planning process for electric utility distribution system operations and investments."

Order No. 20-485 established procedural and substantive DSP planning requirements, as well as the process for Commission review of the Plans.

Order No. 24-421 revised DSP planning requirements and sunset requirements for Smart Grid Reports. Guideline 1g. states that one year after filing a full DSP each utility will file an Interim Update to provide formal, summary-level progress reporting on projects included in the last-filed DSP. Guideline 2 states the Commission will consider whether to accept the Plans, based on finding the Plan meets the criteria and requirements of the Guidelines.

Analysis

Background

On December 18, 2024, PGE filed its 2024 Distribution System Plan under revised DSP Guidelines approved by Commission Order No. 24-421 in November 2024.[1] Since Commission adoption of inaugural DSP Guidelines in 2020,[2] utility distribution spending among Oregon's electric utilities has increased significantly during a period of extreme weather events, wildfires, growing utility load forecasts, and new clean energy targets.[3] Consequently, revised Guidelines required utilities to demonstrate greater transparency of grid needs and justification of solutions to promote spending discipline and establish a throughline for future cost recovery.

PGE's distribution spending continues to increase[4] and affordability challenges remain a key issue. This reality underscores the importance of transparency in distribution system planning to demonstrate that the Company is making strategic investments that deliver system and customer benefits at a reasonable cost to ratepayers.

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1 *In the Matter of Public Utility Commission of Oregon, Investigation Into Distribution System Planning*, Docket No. UM 2005, Order No. 24-421, (Nov. 15, 2024).

2 *In the Matter of Public Utility Commission of Oregon, Consideration for Adoption Staff Proposed Guidelines for Distribution System Planning,* Docket No. UM 2005, Order No. 20-485, (Dec. 23, 2020).

3 Order No. 24-421, p. 4.

4 Docket No. UM 2362, Portland General Electric 2024 Distribution System Plan, p. 304, Table 68: T&D and Grid Mod investments for past five years (Dec. 18, 2024) [*hereinafter* PGE 2024 DSP].

This memo presents Staff's analysis of PGE's distribution spending strategy, highlights specific concerns and expectations for future cost recovery, and suggests opportunities for improvement, ending with a recommendation for Commission action.

Near-term Action Plan Spending Overview

PGE's DSP presents a Near-term Action Plan (Action Plan) that represents planned distribution system investments of more than $2.4B from 2024 through 2028 across six categories: Capacity/Flexibility, Compliance, Customer/Partner, Operations, Reliability, and Grid Modernization.[5] Among these categories, PGE further differentiates between discretionary investments (Capacity/Flexibility, Operations, Reliability, and Grid Modernization) and non-discretionary investments (firm Customer/Partner and Compliance commitments). Over 50 percent of PGE's planned investments are considered non-discretionary. Additionally, 80 percent of planned investments focus on three categories: Customer/Partner, Compliance, and Capacity/Flexibility.

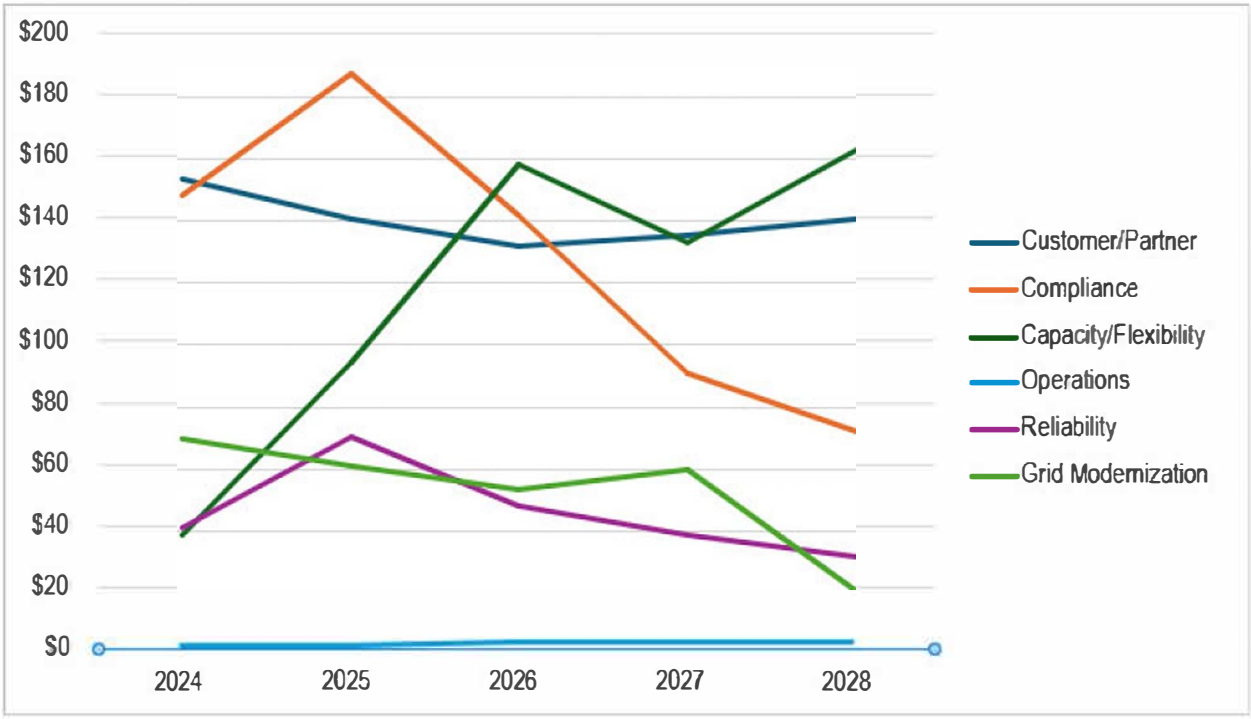
Table 1: Sum of Distribution System Investments by Project and Transmission & Distribution (T&D) Investment Category (2024-2028)

Project Category ($M)	2024[6]	2025	2026	2027	2028	Total	Percent of Total	T&D Investment Category
Customer/Partner	$170.8	$140.6	$131.8	$135.6	$140.5	**$719.3**	**29.8**	**Non-discretionary**
Compliance	$143.4	$187.4	$141.5	$91.1	$72.1	**$635.5**	**26.3**	
Capacity/ Flexibility	$29.5	$94.6	$158.0	$132.8	$162.8	**$577.7**	**23.9**	**Discretionary**
Operations	$2.5	$1.1	$2.3	$2.5	$2.6	**$9.9**	**0.4**	
Reliability	$20.3	$70.3	$47.9	$38.6	$31.9	**$209.0**	**8.6**	
Grid Modernization	$70.1	$60.9	$53.3	$59.8	$20.8	**$264.9**	**11**	
Total	**$436.5**	**$554.9**	**$534.8**	**$460.3**	**$430.5**	**$2,416.3**	**100**	

Over a five-year time horizon, PGE anticipates the largest growth will come from investments that increase capacity and/or flexibility to address load growth or increased demand, with a decrease in compliance and reliability investments after 2025. However, the forecast is only inclusive of projects identified as of July 2024, and new project identification will likely increase the forecasts for those years.[7]

5 Figures have been rounded. PGE 2024 DSP, p. 125, 304.
6 2024 forecast has been updated to actuals except for the Grid Modernization category, PGE response to Citizens' Utility Board (CUB) Information Request (IR) 1.
7 PGE 2024 DSP, p. 125.

Figure 1: Distribution System Investments by Project Category ($M) (2024-2028)



To further understand the Company's investment strategy, Staff requested that PGE identify the project category for each Action Plan investment. This was a helpful step by the Company that exceeded Guideline compliance. Staff analysis shows that a high percentage of near-term spend is attributable to a handful of large investments,[8] with information on the four highest budget categories below.

> Capacity/Flexibility: Three projects (P39016: Harborton-Trojan #3 & #4 230kV, P37781: Bethel-Round Butte 500kV Development, and PXXX33: Bethel 115 kV Rebuild & Bethel-North Marion 115 kV (WVRP)) each have costs greater than **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and together constitute **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent of the category total. Notably, each of these projects focus on **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to address regional load growth. Further observations of these projects are discussed under the *Transmission Projects and the DSP* section.

[8] Ten individual projects and programs represent over $1B of Action Plan spend. See PGE confidential response to informal June 11, 2025, Staff IR.

Compliance: The OH FITNES Distribution (P37218) program addresses the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The total estimated Action Plan spend is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, representing **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent of the category total. Notwithstanding OH FITNES Distribution, wildfire mitigation projects constitute an additional **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent of the Compliance category total.

Customer/Partner: Nearly **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent of this category is represented by eight "blanket" projects totaling over **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in PGE's Action Plan. Traditionally, Staff and the Commission have had little insight into blanket projects, suggesting additional review may be warranted in cost recovery. Additionally, two **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** programs (P35890: Purchase Distribution Transformers and P35892: Purchase Customer Meters) represent **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent of category spend.

Grid Modernization: The largest investment in this category is attributed to a U.S. Department of Energy (DOE) Grant awarded to the Company for accelerating and deployment of grid-edge computing (P39066: Accelerating and Deploying Grid-Edge Computing DOE Grant). The project includes a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** grant of federal matching funds which DOE has since been reported to have terminated. The next two largest investments (P36101: Substation Communication Upgrade (MPLS) and P36522: Distribution Automation) constitute **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percent of the category total.

Within Grid Modernization, PGE's Plan places significant emphasis on its Virtual Power Plant (VPP) as a pillar of the Company's stated distribution strategy.[9] PGE defines its VPP as "the orchestration of Distributed Energy Resources (DERs) and Flexible Load, through technology platforms, to provide grid and operations services."[10] The Plan proposes VPP-related investments across numerous projects and provides insight into the scope of this resource. Table 20 of PGE's

[9] PGE 2024 DSP, p. 30.
[10] PGE 2024 DSP, p. 64.

> Plan proposes a total VPP cost of $880.8M over a 20-year timeframe and the Company's analysis finds a benefit cost ratio of 1.45.[11]

To contextualize PGE's level of overall spend, Staff sought to understand how the Company's proposed investments compared to a "hold steady" level of investing.[12] As a simplified exercise, Staff calculated the theoretical annual amount of distribution capital additions (i.e., new assets or "plant" placed in service) that would equal the annual depreciation of existing distribution assets already in service. Such an amount would keep the revenue requirement on rate base steady, and put neither upward or downward pressure on customer rates. Based on filings and calculations associated with the Company's most recent general rate case,[13] Staff calculated that PGE could invest about $225M per year of distribution capital without impacting the revenue requirement on rate base.[14] PGE's proposed annual investments exceed this amount by at least $200M, and in some years by more than $300M. The result will likely be upward pressure on customer rates. Staff takes this opportunity to underscore the importance of utility spending discipline and cost containment, with an eye towards affordability given recent rate increases.

Concerns with Investment Strategy

Staff recognizes and thanks PGE for its substantial efforts to develop the Plan and engage with Staff and stakeholders. Staff finds many aspects of PGE's Plan and/or subsequent clarifications satisfactory and aligned with Guideline requirements. However, Staff finds significant information gaps within the Company's Grid Needs, Action Plan elements, and Long-term Plan. In the interest of providing constructive and

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11 PGE 2024 DSP, p. 102-103; The benefit cost analysis reflects a utility cash flow cost basis, over a 20-year timeframe, and considers net present values. Though not explicitly labeled as a Total Resource Cost (TRC) perspective Staff understands this analysis to be similar to a TRC perspective, rather than a Utility Cost Test (UCT) perspective, the latter of which more closely resembles IRP modeling.

12 To be clear, Staff notes this analysis did not focus on maintaining *the grid*, but rather on maintaining *investment*.

13 Docket No. UE 435 Compliance filing, *PGE Advice No. 24-39 Unbundled ROO_Final order* workpaper/*Distribution ROO* tab, Depreciation and Amortization expense.

14 Staff assumptions include:
Staff focused just on capital investment and omitted O&M expense.
PGE's distribution plant depreciates at a rate of 7.1 percent. Depreciation expense ($224K) divided by Net distribution plant ($3.148M).
Normally, plant depreciation is dictated by the plant category. For ease, Staff generalized and calculated a distribution "over-all" depreciation rate.
PGE calculates depreciation based on Net Utility Plant, so as net plant balances start to decline, depreciation expense does as well. This means that depreciation expense, all other things unchanged, could also be held steady.

actionable feedback, Staff focuses on Plan elements that are intended to address the most pressing grid needs and demonstrate strong justification for investment decisions. The following sections highlight transparency concerns and Staff recommendations.

Grid Needs

PGE's Plan presents six prioritized grid needs that were analyzed for solutions as part of the 2025 capital cycle.[15] This 2024 DSP provides a more limited list as compared to the information presented in the Company's 2022 Plan, where PGE identified the list of current grid needs, older grid needs requiring reevaluation, and possible grid needs for the next capital cycle. To illustrate this limitation, Figure 2 below excerpts the six grid needs identified in Table 22 of the Plan that are associated with equipment that is typically nearing its thermal limits and requires immediate attention.[16] While the Company ranked these needs with prioritization scores between 4.9 and 2.5, it is not clear if there were other grid needs scored as part of the annual evaluation process that did not meet the prioritization threshold and the factors contributing to their exclusion. Further, Staff notes that Figure 27 in Appendix B of the Plan presents a process that appears to be inclusive of grid needs resulting not only from load violations, but also from the Company's Asset Management Planning (AMP) Risk model and operational constraints/issues. However, Table 22 does not appear to present full results from this process. Clarity regarding which grid needs may have been deprioritized or reevaluated based on scoring criteria or other factors would help Staff understand the Company's decision-making process and provide insight into possible capital investments and/or non-wires solutions (NWS) needed to address future grid needs.

[15] PGE 2024 DSP, p. 109.
[16] PGE Reply to Staff and Stakeholder Comments on PGE's 2024 DSP, p. 20 (July 14, 2025) [*hereinafter* PGE Reply Comments].

Figure 2: Excerpt of PGE's Table 22, List of Prioritized Grid Needs

Table 22. List of prioritized grid needs

Priority	PGE location	Grid need	Project	Total
1	Evergreen substation	Add distribution infrastructure	Evergreen	**4.9**
2	Swan Island substation	Substation Rebuild	Swan Island	**4.8**
3	Glisan substation	Industrial load growth in Gresham	Glisan	**4.5**
4	New Station E	New Load/Capacity need, rebuild substation	Sub E	**4.4**
5	Glencoe-Glisan	Capacity addition to implement other grid need mitigations	Glencoe-Glisan	**2.7**
6	Holgate substation	Capacity addition to implement other grid need mitigations in SE Portland, lack of SCADA telemetry, feeder reliability improvements, aging assets	Holgate	**2.5**

A wider reporting lens would also be responsive to stakeholder interests. For example in its Round Two Comments, OSSIA requested an update on the issue of limited generation feeders.[17] While absent in the 2024 Plan as a grid need or proposed investment, "Generation Limited feeders" was identified as the seventh highest ranking grid need on the list of "Grid Needs for the 2026 Plan" presented in PGE's DSP Workshop on July 31, 2025.[18] Future DSPs would also be improved by establishing clearer connections between grid needs and proposed solutions, which Staff discusses below in the *Investment Prioritization* and *Demonstration of Benefits or Value* sections.

Near-term Action Plan

The revised Guidelines require a prioritized list of proposed solutions and projected costs to address near-term grid needs.[19] For investments more than $2M, a project narrative, estimated timeframe, prioritization method, and description of alternative solutions considered are required. When applicable, utilities should also provide a

[17] Oregon Solar + Storage Industries Association's (OSSIA) Round Two Comments (Sept. 22, 2025); Docket No. UM 2197, PGE Distribution System Plan Part 1, p. 111 (Oct. 2021).

[18] Recording of PGE's July 31, 2025, DSP Workshop found at https://portlandgeneral.com/about/who-we-are/resource-planning/resource-planning-engagement.

[19] Order No. 24-421, p. 26-27.

description of how an investment may be coordinated with other planning processes, and with non-distribution asset strategies (i.e., transmission).[20]

Through these Guideline requirements, Staff seeks insight into when and how the Company plans to invest in the distribution grid, and how it demonstrates discipline in prioritizing and right-sizing investment decisions to address grid needs and deliver ratepayer value. PGE's Action Plan has provided insight into its near-term investments, but Staff finds that the Plan lacks transparency regarding the number of high-cost investment decisions made and their justification. Staff discusses below the Company's investment prioritization, demonstration of customer value, consideration of alternatives, and coordination with transmission planning.

Investment Prioritization (Guideline 8a. and 8biv.)
Staff was unable to identify a clear prioritization methodology for the investments selected in the Company's Action Plan. While Staff appreciates that PGE's Plan provides a high-level overview of its capital planning process,[21] the Plan did not demonstrate how the quantitative or qualitative outcomes of the capital planning assessments led to the identification, prioritization ranking, and selection of its near-term investments. In theory, an investment addressing the top-ranked grid need should have greater priority than an investment addressing the ninth ranked grid need. However, the Plan does not clearly provide how the Company evaluated and prioritized projects addressing grid needs against other investments for inclusion in the Action Plan. Poorly prioritized investments can lead to unnecessary cost burdens on ratepayers. To be responsive to the Guidelines and significant customer affordability challenges, in future DSPs the Company should demonstrate how it determined near-term investments from a clear and comprehensive decision-making framework.

In PGE's Reply Comments, Staff learned about a new Risk Informed Decision-Making (RIDM) framework PGE is using to evaluate a project or program's overall "value spend efficiency" when prioritizing investments.[22] While the Company did not fully implement RIDM for investments within the 2024 Plan,[23] Staff is encouraged by this development and the Company's plans to use RIDM to select and prioritize investments.

Demonstration of Benefits or Value (Guideline 8bi.)
Staff appreciates PGE's innovative application of benefit cost analysis (BCA) to the VPP. Staff looks forward to seeing PGE extend the application of BCA to additional

[20] *Id*. p. 28.
[21] PGE 2024 DSP, Appendix J, p. 324-329.
[22] PGE Reply Comments, p. 19-20.
[23] PGE Reply to Round Two Comments, p. 14.

investment types in the future. However, for most investments in the 2024 Plan, clear performance metrics to demonstrate benefits and customer value are lacking. Further, only about ten percent of project investment summaries in the Action Plan show clearly labeled grid needs. PGE has missed an opportunity to demonstrate investment efficiency and need.

Staff expects to see use of data-driven, benchmarkable metrics aligned with investment type. Such metrics would address Guideline requirements, demonstrate efficient spending, and more effectively communicate the Company's decision-making rationale and justification. Staff offers the following illustrative examples of such metrics:

- Capacity/flexibility metrics: the amount of capacity delivered and under what cases it would be used including the probability of the case, and the history that demonstrated that frequency.
- Compliance investments: the impact of non-compliance, the basis for non-compliance, and the authority determining compliance.
- Customer/partner investments: load at risk by year and the expected unserved energy for each of the forecast years.
- Reliability investments: metrics on $/avoided customer interruption and the reliability standard that is in jeopardy.
- Obsolescence/replacement investments: equipment failure rate, consequences of failure, recent diagnostic and forecast deterioration rate.
- Grid modernization investments: a holistic BCA with clear documentation of assumptions used.

Staff's review concluded that the Plan linked only two of the six grid needs identified in Table 22 to corresponding projects in Appendix E.[24] Additionally, Staff found that only half of the 12 identified grid needs from the 2022 Plan are clearly connected to Appendix E projects in the 2024 Plan.[25] Staff acknowledges that there are legitimate reasons that grid needs identified within a given planning cycle may not correspond to proposed investments found in a subsequent DSP. Examples may include load growth that did not materialize or project solutions that are still in development. Staff also recognizes that projects may originate for reasons other than grid needs. However

[24] Projects linked to Table 22 grid needs included **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, PGE confidential supplemental response to Staff IR 15.

[25] Projects linked to 2022 Plan grid needs included **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, PGE confidential supplemental response to Staff IR 16.

looking ahead, as grid needs continue to be identified and catalogued in future DSPs, Staff expects clearer and more consistent presentation of the basis for investments in order to better demonstrate ratepayer value. In particular, Staff expects the Company to clearly identify investments originating from a grid need.

Consideration of Alternatives (Guideline 8bv.)
PGE's consideration of alternatives appears to be inconsistent across investments. Approximately one half of the project investment summaries in the Action Plan provide descriptions of alternative solutions. Where alternatives are discussed, they are more qualitative than quantitative, making it hard for Staff to evaluate or validate. This apparent inconsistent consideration of alternative solutions, especially low-cost, incremental options, presents risks to ratepayers in over-priced or premature expenditures.

P36101: Substation Communication Upgrade (MPLS) is an illustrative example. The project **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. However, the investment summary lacks a thorough discussion of the costs, benefits, or risks of these approaches. More concerningly, the investment summary also lacks information on soliciting or receiving bids or estimates from different providers for the chosen approach.

The absence of data, or other demonstrations of the Company's work to consider and develop alternative solutions, for a significant percentage of Action Plan investment summaries makes it difficult to demonstrate cost-containment, spending discipline, or efficient investment of ratepayer dollars. More consistently providing descriptions of alternative solutions considered, and where available, quantifying costs and benefits would begin to address this shortcoming of the 2024 Plan.

In Round One Comments, the Joint Energy Advocates noted that the Plan does not identify or include Non-Wire Solutions (NWS) concept proposals as required by the Guidelines.[26] In Round Two Comments, Staff recommended that PGE explain to what extent NWS were considered to address the Plan's six identified grid needs, and if they were not considered, the Company's reasoning. Staff appreciates PGE's response that NWS were considered for each of the six identified grid needs, with information on related assessments.[27] Staff finds this acceptable for meeting Guideline 7d. Staff notes

[26] Order No. 24-421, Guideline 7d., p. 26.
[27] PGE Replies to Round Two Comments on PGE's 2024 Distribution System Plan, p. 10 (Sept. 19, 2025).

that the Company's summary of Grid Need 5 indicates this need was met through a type of NWS: transferring customer load from one feeder to another. While transferring load is not a DER-focused solution, Staff wonders whether this approach could have been used as a NWS concept proposal to meet Guideline 7d. Staff anticipates that NWS will be discussed as part of a future process for Guideline improvements.

Virtual Power Plant (VPP)

The Plan is a step forward in presenting how the Company is approaching the VPP. The Plan articulates how the VPP calls resources and their relationship to technology, and provides scale for the capacity of the resource.[28] The Plan also begins to present economics of the VPP through BCA, an important step forward in quantifying the value of this resource.[29] Staff is concerned that the analysis lacks a rigorous estimate of capacity contribution, and inconsistently represents enabling and incremental investments. The Plan does not explain how the VPP will result in customer and system value in the future, and most importantly, the VPP appears to lack grounding in least-cost, least-risk resource evaluation.

Staff expects the VPP to be subject to IRP and CEP endogenous modeling to inform the resource's role in the Company's least-cost resource investment strategy. While the Company's BCA of the VPP provides a useful lens through which to consider the investment, BCA does not address questions about right-sizing the investment. PGE's next IRP/CEP modeling should identify a least-cost, least-risk acquisition target (energy and capacity) for the VPP based on a holistic assessment of the costs and realistic assessment of the benefits derived from the resource compared to other options. To the extent possible, the IRP/CEP modeling should capture grid services provided by the VPP. Staff looks forward to working with the Company to achieve transparency in modeling the resource in the next IRP/CEP, including a clear understanding of the Company's assumptions underpinning the VPP resource.[30]

Future DSPs should propose the capital investments necessary for the VPP based on the results of the IRP/CEP modeling. To the extent applicable, the DSP should highlight co-benefits and interdependencies of VPP enabling investments with other solutions considered for meeting identified grid needs.

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28 PGE 2024 DSP, p. 65, Figure 19.

29 *Id.* p. 103, Section 5.2 and Figure 20.

30 Examples of important modeling assumptions include costs of legacy components being folded into the VPP, costs of incremental investments, costs of investments in enabling systems or technology, and how each of these costs are represented in the model. Also important are assumptions on benefits of legacy components, benefits of incremental investments, benefits of the overall VPP, and how each of these benefits are represented in the model.

Future flexible load plans should propose programmatic investments necessary for the VPP, also based on IRP/CEP modeling. The flexible load plan should also include performance and cost-effectiveness analysis to validate the DSP and IRP/CEP information. Staff views these planning practices as complimentary and coordinated. Staff will consider PGE's planning efforts as part of the prudence review of VPP investments in cost recovery.

For the VPP, Staff also expects a clear articulation and presentation of proposed future spending and customer benefits. The VPP, as presented to date, lacks clear quantifiable goals which are often obvious for other distribution investments, such as an increase in capacity, and compliance with a new safety standard, among others. Staff notes PGE's conceptual Figure 1 as a possible example of a helpful presentation of actual proposed spending and anticipated benefits over time, using reasonable assumptions based on the results of the IRP/CEP modeling.[31]

Transmission Projects and the DSP

PGE included in the Action Plan thirty investments with transmission scope, among the costliest in the Plan.[32] Inclusion of transmission projects is helpful as it presents a more comprehensive picture of the grid and demonstrates consideration of the Company's related planning processes.[33] Three of the ten projects with the largest estimated Action Plan spend are transmission projects:

- P39016: Harborton-Trojan #3 & #4 230kV, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.
- P37781: Bethel-Round Butte 500kV Development, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.
- PXXX33: Bethel 115 kV Rebuild & Bethel-North Marion 115 kV (WVRP), **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Unfortunately information provided in both investment summaries in Appendix E and in discovery responses does not clearly delineate between transmission and distribution scope and relative costs.[34] This has limited Staff's understanding of PGE's Action Plan

[31] PGE 2024 DSP, p. 24.

[32] PGE's 57 kV DSP Appendix Outline Final Draft in Compliance with Order No. 25-100, (August 12, 2025).

[33] Guideline 8vii. calls for description of if, and how the proposed investment interacts with non-distribution asset strategies, and if made, what impact does the proposed investment have on other network assets.

[34] Guideline 8bi. calls for a project narrative including benefits of the project, and the asset classes and unit counts of the proposed solution; Guideline 8biii. calls for estimated project cost/expenditure amount.

spending. When project costs are sizeable, as is the case here where three projects represent over ten percent of Action Plan spend, it casts notable uncertainty over Action Plan spending estimates. The information provided also fails to discuss the interaction of transmission investments with distribution strategy, or the origin or basis for the projects.[35] PGE could improve transparency and confidence in spending estimates with clear articulation of scope and cost, origin of transmission projects, foundational assumptions, and project basis. This should include clear explanation of how, or whether, a transmission project's scope impacts distribution system strategy and how estimated costs and timing reconcile and align with the Company IRP/CEPs.

In Docket No. UM 2347, PGE sought Commission support to reclassify 57 kilovolt (kV) facilities from distribution assets to transmission assets. Parties reached a stipulated agreement adopted by the Commission in Order No. 25-100.[36] Term Five of the stipulation established commitments for PGE to integrate specific information about higher-voltage assets into its future DSPs, and to work with Staff to determine additional information, beyond that in the 2024 Plan, to address questions about how the Company's distribution system and transmission planning interrelate.[37] PGE filed the additional information October 3, 2025, as a supplemental filing to the 2024 Plan.[38]

Staff thanks PGE for preparing the supplemental filing and highlights select issues:

- Staff was pleased to see that PGE's distribution planners work closely with transmission planners using shared forecasts, models, and regulatory timelines.[39] Staff suggests that future DSPs and Local Transmission Plans document these shared inputs for transparency.
- The supplemental filing does not provide additional clarity about the scope or cost categories of projects. However, the Company provides two illustrative examples of why such clarity is important. First, transmission planning decisions can drive the need for related distribution system changes. To illustrate, a change in the source transmission voltage may require distribution substations be rebuilt to match the new transmission voltage.[40] In a second example, precursor projects (upgrades that enable subsequent improvements) often straddle transmission and distribution domains but provide foundational capacity needed

35 Guideline 8bi. calls for a project narrative including, as available, foundational assumptions. The narrative should identify the grid need(s) addressed by the project, and if the project was prompted by a standard, company policy, or other requirement.
36 Docket No. UM 2347, Order No. 25-100, (March 13, 2025).
37 *Id*. p.10, Term Five.
38 PGE Distribution System Plan, Supplemental 57kV Filing, (Oct. 3, 2025).
39 *Id*. p. 5.
40 *Id*. p. 6.

for future DER adoption, service to new load, or feeder automation.[41] In instances such as these, should PGE strive to demonstrate investment efficiency and cost-containment with clear presentation of scope, cost, and origin information noted above.

- PGE aligns processes to prevent orphaned distribution investments.[42] The supplemental filing points to cases in which distribution enhancements are postponed until a transmission upgrade is completed, or in which a NWS is used as a bridging strategy while waiting for large projects completion.[43] Staff appreciates these cases and encourages PGE to present them in future DSPs as examples of cost containment and investment efficiency.
- For transmission projects, PGE develops rough order of magnitude estimates, with variability of -50 percent/+100 percent, based on a widely accepted standard from the Association for the Advancement of Cost Engineering International. This is conducted at the project's initial conceptualization.[44] Staff is interested in better understanding how this practice may be applied to distribution projects, and to the extent it is, whether such error margins are used in evaluating alternative solutions.

Long-term Plan

The DSP's Long-term Plan is intended to provide insight into the Company's ten-year vision and how it aligns with state policy goals and PUC objectives. The Long-term Plan should also serve as a preview of investments that may be seen in future distribution system plans.[45]

PGE's plan includes a long-term vision that centers on the Company's grid modernization strategy with the intended goals to improve safety, reliability, and achieve HB 2021 decarbonization targets. The Company highlights DER deployment with investments in grid management systems (i.e., DERMs), advanced protection for distribution infrastructure, advanced computing for real time management, telecommunications, and cybersecurity.

Staff finds that PGE's long-term vision is clear and consistent with the development of near-term investments in the Action Plan. However, the Plan lacks detail related to planned investments beyond 2028. For example, the Plan states that half of the feeders

41 *Id*. p. 9.
42 PGE uses this term to describe projects that cannot fulfill their intended function because upstream infrastructure has not been built yet.
43 PGE Supplemental 57kV Filing, p. 9.
44 *Id*. p. 14.
45 Order No. 24-421, p. 28.

on the grid are planned to be FLISR enabled by 2035, but the Company's roadmap does not offer implementation specifics over the next six to ten years.[46] As DSP and utility forecasting matures and evolves, Staff hopes to see more investments appear first in the Long-term Plan before flowing into the Action Plan with additional certainty and specificity, and ultimately into implementation.

Additionally, the Long-term Plan does not address implications of FERC Order 901.[47] These include development of inverter-based resources (IBR) performance standards and development of future IBR-related planning considerations, including data sharing, model validation, and planning and operational studies, and how they may affect the Company's future distribution planning.

To aid in future cost recovery efforts, Staff recommends that in future Plans the Company better identify and articulate strategy for expected actions and expenditures the Company will take in years six through ten, per Guideline requirements 9b. and 9c. This should include how the Company's planning may be affected by evolving state and federal policies.

Cost Recovery Implications
Docket No. UE 459 provides a unique opportunity to review fifteen months of the Company's actions and investments, and Staff will conduct a prudence review of those investments.[48] Staff review of PGE's Plan can identify information, concerns, and issues for consideration in Docket No. UE 459. Staff expects investment review in Docket No. UE 459 to advance expectations for demonstrated justification of investments, commensurate with customer value under affordability pressures.

After reviewing the 2024 Plan, Staff observes that PGE's estimated investments exceed steady-state spending. The Plan does not consistently demonstrate benefits/value of planned investments or consideration of alternative solutions. In reviewing the DSP, Staff identified a list of specific concerns, outlined in Attachment A. Most of Attachment A is currently in scope of Docket No. UE 459, an active contested case.

Moving Forward / Continuous Improvement
Staff is encouraged by the Company's implementation of RIDM as a tool to prioritize investments and to demonstrate value-spend efficiency. Staff appreciates PGE

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[46] PGE 2024 DSP, p. 92; a total of 35 of 695 feeders have been retrofitted to respond to reliability events. See PGE 2024 DSP, p. 32.
[47] Federal Energy Regulatory Commission, Docket No. RM 22-12-000, Order No. 901, 88 FR 74250 (Oct. 19, 2023).
[48] *See* Docket No. UE 459, PGE Application for Distribution Plan Alternative Rate Mechanism.

underscoring in Round Two Reply Comments that RIDM is still being tested and refined before implementation can be completed.[49] In the Company's next DSP, Staff requests a full update on RIDM implementation. To the extent RIDM is implemented, Staff would find value in clear documentation of which projects were subject to RIDM, reviewing investment-specific RIDM end-scores, work-papers underlying those end-score calculations, and documentation and discussion of instances when RIDM was overridden by other factors.

PGE noted in Round Two Reply Comments that consideration of how RIDM is applied to capital projects may be relevant in the next DSP, pending implementation.[50] With this in mind, Staff takes this opportunity to underscore the importance of clearly presenting whichever methodology the Company uses to prioritize investments. Staff will consider the Company's process to ensure a clear and cost-efficient approach to prioritizing investments (large and small, discretionary and non-discretionary) when reviewing prudence of investments in cost recovery

Staff and stakeholder review of PGE's Plan has resulted in numerous key learnings, examples of which have been discussed here. Recently passed Oregon House Bill 3336 includes requirements for electric utilities to file a strategic plan for using grid enhancing technologies (GETs). Staff anticipates future DSPs to reflect synergies with this new GET process. In addition, we await upcoming Plans from Pacific Power and Idaho Power that will bring further key learnings. Staff plans to engage utilities and stakeholders later in 2026 to identify recommended Guideline revisions, scope, and reporting cadence.

DSP Guidelines call for utilities to file an Interim Update one year after a full DSP to provide progress updates on projects. Staff believes the Interim Update strikes the right balance of effort to all parties for improved understanding of investments between Plan filings. PGE's Interim Update is due in December 2025, per Guideline 1g, concurrent with cost recovery proceedings in Docket No. UE 459. With this consideration, Staff recommends the Commission delay PGE's Interim Update from December 18, 2025, to December 1, 2026.

Conclusion

Staff thanks PGE for its significant efforts in developing the 2024 Plan and working with Staff and stakeholders to understand it and identify areas for continuous improvement. The Company has substantially advanced its DSP from its 2021 and 2022 filings in

[49] *Id*. p. 14.
[50] PGE Round Two Reply Comments, p. 14.

many ways. Staff finds the 2024 Plan meets the requirements of current DSP Guidelines. Staff will continue to work with PGE to evolve and improve its next Plan within an increasingly complex planning environment.

PROPOSED COMMISSION MOTION:

Accept Portland General Electric's 2024 Distribution System Plan and direct the Company to file an Interim Update by December 1, 2026.

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Attachment A

Staff shares its concerns and observations below from review of the PGE 2024 DSP. The following discussion relates to investments for which the Company seeks cost recovery in Docket No. UE 459:

- PGE has included investments in the Action Plan that may fall outside of the distribution classification or be at issue in other planning venues, such as transmission investments and wildfire mitigation investments.
- Compliance: P37218: OH FITNES Distribution. Staff noted in Round Two Comments that information provided fails to show the BCA of the investment and is missing metrics.[51]
- Customer/Partner: P36954: Tonquin Substation Build. Staff notes there is a stated need to serve new load, but no analysis of the shortfalls of the existing system if the project does not go ahead. The information states that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** is the only solution but does not provide criteria for pursuing such a solution, or a comparison to other alternatives. There are statements about additional benefits resulting from the project, but no demonstration of such benefits is provided.[52]
- Customer/Partner: P37421: Foreign Utility Blanket. Staff notes the information provided does not include rationale for investments, BCA or metrics used to approve investments, or consideration of alternatives.[53]
- Reliability: P36617: South Milliken 57kV Line Rebuild. Staff raised concerns in Round Two Comments about preliminary cost estimates and a lack of discussion about **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Staff would expect to see justification for the cost and schedule to be linked to metrics on **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and relevant reliability metrics.[54]
- Reliability: P37266: Reedville Substation Rebuild. Staff notes the information provided did include some quantified improvement in risk reduction but did not include benefits and costs of the proposed investment or reasonable alternatives considered.[55]
- Grid Modernization: P36522: Distribution Automation. Staff raised concerns in Round Two Comments about this investment's omission from the Long-term

[51] PGE 2024 DSP, Conf. Appendix E, p. 122 to 125; Staff Round Two Comments, p. 6.
[52] PGE 2024 DSP, Conf. Appendix E, p.97.
[53] *Id*. p.165.
[54] PGE 2024 DSP, Conf. Appendix E, p. 71; Staff Round Two Comments, p. 6.
[55] PGE 2024 DSP, Conf. Appendix E, p. 139.

Plan, and a lack of discussion regarding metrics, consideration of lower cost alternatives, and relative costs and benefits.[56]

- Grid Modernization: P36101: Substation Communication Upgrade (MPLS). Staff notes the information provided did not include metrics or explanation of benefits for the upgrade, explain the reason for choosing the selected investment, or as noted previously, information on bids from other providers.[57]
- Grid Modernization: P37600: DPF Install. Staff notes the information provided did not explain the selection of the preferred investment or include information on bids from other providers. The information references the initial cost estimate **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, raising concern about whether the investment was the most cost effective.[58]
- Grid Modernization: P39058: Enterprise DERMS / DER SOR (VPP) and additional related projects. Staff's primary cost recovery concern for the VPP is that the resource appears to lack grounding in least-cost, least-risk evaluation. Additionally, Staff has engaged with specific questions about the scope, cost, and benefits of the VPP for some time, with the Commission providing direction in Order No. 24-454 for PGE to provide more detailed BCA and other information in the Company's Flexible Load Plan to facilitate evaluation of the performance of the VPP.[59] In the Company's compliance filing, PGE delayed reporting on a holistic BCA inclusive of VPP labor costs approved in rates.[60] Staff highlights the following concerns in reviewing PGE's Plan and feels the Company must provide clarity on these aspects for future cost recovery:

    - Staff has concerns about the capacity targets set for the resource. For example, the Plan does not provide evidence or support for its planning assumption to build out 350 MW of distributed solar by 2030, as presented in Figure 19. In response to Staff's Round Two Comments, PGE replied that the visualization and the associated list of resources should be understood as illustrative, and that the composition of the VPP will evolve.[61] This raises concerns that PGE's VPP capacity targets lack firm foundation and calls into question the validity of costs and benefits used in the BCA. Staff expects PGE in its next IRP/CEP to identify a least-cost, least-risk acquisition target (energy and capacity).

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56 PGE 2024 DSP, Conf. Appendix E, p. 62; Staff Round Two Comments, p. 5.
57 PGE 2024 DSP, Conf. Appendix E, p. 41.
58 *Id*. p. 205.
59 *In the Matter of PGE Request for a General Rate Case*, Docket No. UE 435, Order No. 24-454, p. 50 (December 20, 2024).
60 *In the Matter of PGE Flexible Load Plan,* Docket No. UM 2141, *VPP Data Filing,* p. 6 (September 17, 2025).
61 PGE Round Two Reply Comments, p. 8.

- Staff has concerns about how incremental investments are defined and represented in the VPP BCA. For example, the Action Plan includes two investments in the Dispatchable Standy Generation program to expand the program and to retrofit pollution controls (P39067: DSG Expansion, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and P37600: DPF Install, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**) however, it is not clear how the BCA considers these investments relative to the legacy component costs. In Round Two Comments, Staff expressed concerns that VPP desk staffing costs are already included for components such as the Flexible Load Plan pilots and programs. The DSP fails to demonstrate either that new VPP desk staffing offsets existing programmatic staffing currently operating dispatch, or that new VPP desk staffing delivers additional benefits.
- Staff has concerns about how consistently enabling investments are defined and represented in the VPP BCA. For example, while it appears that the BCA considers FLISR enabling investments (P36522: Distribution Automation, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**) it is not evident that the BCA considers two other investments Staff understands are closely related to the VPP: P37427: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and P39066: Accelerating and Deploying Grid-Edge Computing DOE Grant with **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Staff provides the following observations and concerns for investments not in scope of Docket No. UE 459:

- Capacity/Flexibility: P39016: Harborton-Trojan #3 & #4 230kV. Staff notes above, and in Round Two Comments, concern about articulation of this investment's scope and accounting of costs, missing metrics and prioritization, and rationale.[62]
- Capacity/Flexibility: P37781: Bethel-Round Butte 500kV Development. Staff notes concern about articulation of this investment's scope and accounting of costs, missing metrics and prioritization, and rationale.[63]
- Reliability: P36390: Redland Substation Upgrades. Staff notes the information provided discussed a variety of benefits from this investment, but did not quantify those benefits, or costs, of the proposed investment, or of reasonable alternatives considered.[64]

[62] PGE 2024 DSP, Conf. Appendix E, p. 251; Staff Round Two Comments, p. 4 (Aug. 22, 2025).
[63] PGE 2024 DSP, Conf. Appendix E, p. 233.
[64] *Id*. p. 52.