BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UM 2377
Investigation into Marginal Cost Study Treatment of Costs for Large Customers and Further Modifications to Portland General Electric Company's Rule C and Rule I

PORTLAND GENERAL ELECTRIC

Opening Testimony

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I. Introduction and Summary

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Jaki Ferchland. I am the Senior Manager of Pricing, Tariff and Power Cost Recovery.

My name is Isaac Barrow. I am the Senior Manager of Data Centers and Growth.

Our qualifications are provided below in Section VIII.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond comprehensively to the priorities and concerns raised by the Commission in Docket UE 430, where the Commission approved PGE's initial steps to ensure the fair and forward-looking recovery of new large load connection costs. PGE remains firmly committed to meeting our statutory obligation to serve all customers reliably and equitably. Our proposals reflect our recognition that the costs associated with rapid large load growth—particularly from data centers and similarly energy-intensive facilities—must be allocated appropriately to maintain system integrity while supporting beneficial economic development and helping to support the transmission and distribution investments required to deliver on the State's vision of a more equitable and cleaner system. Our testimony addresses the development of a dedicated Data Center rate class, refinements to marginal cost methodologies, updates to Rules C and I, enhancements to Contributions in Aid of Construction (CIAC) policies, and opportunities for direct resource contracting. We also speak to broader system and policy impacts, including implementation of House Bill 3546 (HB 3546), the treatment of the load-following credit, and the evolving implications of large load integration on system planning and cost recovery.

Building on these foundational elements, our testimony emphasizes that well-designed tariffs, cost-reflective rates, and transparent contracting mechanisms are critical to sustaining system reliability and enabling predictable, economically beneficial load growth across Oregon. The changes PGE proposes in this docket are designed to support equitable cost responsibility--ensuring all customers, including new large loads, contribute fairly to the infrastructure and energy services they use.

PGE supports the Commission's continued investigation and shares the goal of establishing a clear, enforceable framework that enables utilities to plan for, invest in, and deliver the infrastructure needed to serve all customers—existing and new—without compromising fairness, affordability, or long-term system planning. As Oregon continues to grow and decarbonize, it is essential that large loads such as data centers are integrated in a way that reflects their contribution to system needs and supports the state's broader energy and economic goals.

Q. How did UE 430 conclude, and what is the purpose of the continued investigation in Docket UM 2377 (UM 2377)?

A. In docket UE 430, the Commission approved PGE's proposed changes to Rules C and I and required that any service contracts entered into during the interim period would be subject to change based on any changes required as a result of the final order in this UM 2377 investigation. PGE proposed changes are designed to enable service to new large load customers on terms that fairly allocated the cost of serving these new customers while maintaining fairness of how infrastructure costs are shared and avoiding unintended cost shifts among customer classes. These changes included separating new customer load requests into three categories based on requested capacity, instituted a new contract process for customers with requested capacity greater than 30 MW, created new credit requirements, instituted a minimum transmission demand requirement and capacity exceedance penalties, set distribution demand requirements and exit fees, and specified a process for system capacity reallocations. UM 2377 provides the opportunity to expand on certain topics considered in the UE 430 docket, as well as discuss those not included in the scope of UE 430 such as marginal cost study implications, Contributions in Aid of Construction (CIAC), HB 2021 compliance and the larger ratemaking implications of large load customers.

Q. How is PGE's testimony in this proceeding shaped by HB 3546, which was adopted by the Oregon State legislature and signed by the Governor on June 19, 2025?

A. PGE's proposals in this proceeding reflect the directives of HB 3546 and are consistent with its requirements. Consistent with the legislation, PGE is introducing Schedule 96, a new data center rate class for customers engaging or who will engage in data center business with demand of 20 MW and greater. This new rate class enables the appropriate allocation of the cost of serving these customers and addresses concerns about undue and unreasonable cost shifting. PGE is recommending a framework that emphasizes three core principles, (1) balancing the needs of all customers, (2) accountability with strong obligation for data center customers to demonstrate commitment that can be used in planning and (3) equity and reliability commitments to all customers, mitigating cross-class subsidization

To address cost shifting from one customer class to another we are proposing (1) updates to marginal cost of service studies, (2) introduction of generation demand charges, not only in Schedule 96, but in all industrial schedules that will allow us to enable the addition of a minimum generation demand charge, (3) optional CIAC on distribution assets, and (4) an option for special contracting directly with Schedule 96 customers for the cost of service, including for generating resources. PGE Exhibit 101 provides a draft of the Schedule 96 tariff.

Q. Please summarize the key elements of your testimony.

A. In Section II, we provide details of the creation of Schedule 96, our new data center rate class. Section III presents updates to our marginal cost of service studies that are intended to better align cost allocation with cost causation principles applicable when system investments are driven by peak demand growth, ensuring the approach remains durable over time. In Section IV we revisit positions taken in the prior docket and introduce several new proposals, including a generation demand charge and the application of a minimum generation demand charge. Section V introduces a proposal for implementing contributions in aid of construction (CIAC) related to distribution infrastructure. Section VI discusses the potential use of special contracts, as authorized by HB 3546, for the cost of service, including as applicable generation resources to serve large customers. Finally, Section VII provides context related to the Load Following Credit.

Q. What is the cumulative impact of PGE's proposed changes on customers?

A. If adopted, PGE's proposed changes would not affect the final revenue requirement established in Docket UE 435 (UE 435). However, they would modify how costs are allocated among customer classes, which in turn would affect customer pricing. Table 1 below illustrates the baseline impact of adding Schedule 96 to the approved final compliance filing from UE 435. Note that this is the hypothetical increase from 2024 rates. The cost impacts shown throughout the remainder of this testimony will be based upon this scenario (adding Schedule 96 to the final approved UE 435 compliance filing) for ease of understanding. Table 2 shows the cumulative impact of the marginal cost studies based on the premise that

Schedule 96 was included in the approved final compliance filing from UE 435. PGE Exhibit 102 details the impacts of all marginal cost changes on the UE 435 Compliance Filing, assuming Schedule 96 was included.

Table 1
Percentage Changes between Customer Classes
[As though updated for January 1, 2025]

Customer Class	2025 GRC	2025 GRC w/ Sch 96
Schedule 7	5.4%	5.3%
Schedule 32	8.2%	8.5%
Schedule 83	8.5%	8.6%
Schedule 85	6.8%	6.8%
Schedule 89	4.2%	4.5%
Schedule 90	6.0%	6.5%
Schedule 96	[embedded in 89 & 90]	4.7%
COS/DA Total	6.3%	6.3%

* Customer Impact Offset not applied

Table 2
Incremental Percentage Impacts of Marginal Cost Proposals
[Impacts presented as change from 2025 scenario with Sch 96]

Customer Class	Total Impact of All Marginal Cost Changes
Schedule 7	-0.6%
Schedule 32	-2.3%
Schedule 83	-1.4%
Schedule 85	0.7%
Schedule 89	-3.7%
Schedule 90	-0.7%
Schedule 96	17.9%
COS/DA Total	0.0%

* Customer Impact Offset not applied

Q. Why is a balanced approach crucial to the outcomes of this docket?

A. Without a balanced approach, Oregon risks losing both economic opportunity and control over rising system costs. Large loads like data centers are mobile and will seek jurisdictions with predictable interconnection and cost structures. If Oregon lacks that clarity, these investments may shift to other jurisdictions—potentially in other Pacific Northwest territories or throughout the country—leaving the communities in our service areas and the state without the tax base, jobs, and infrastructure benefits they could bring. As Chair Tawney's recent letter to Governor Kotek highlighted, this is a moment of unprecedented need for investment in the transmission and distribution system to deliver on the State's vision of a more equitable and cleaner system. New large loads present an opportunity to advance these "broader state goals and responsibilities of the Commission." Exhibit 103, Chair Tawney, August 1, 2025, Letter to Governor Kotek, p. 1 and 12.

At the same time, even if these loads locate elsewhere, they will still compete for limited regional power and transmission resources. That added demand can drive up market prices, tightening supply and increasing procurement costs for all utilities—including those utilities that do not serve the load. The result: PGE's customers may face a higher cost of service without receiving any of the benefits that larger loads can bring when integrated responsibly.

UM 2377 is an opportunity to avoid that outcome and chart a better course. With a durable, transparent and equitable framework, Oregon can remain competitive, responsibly welcome strategic new load growth, and align that growth with the goals of affordability, reliability and clean energy. Oregon's electric system is a shared asset—and the rules and policies adopted under UM 2377 must reflect a shared commitment to long term system health, customer equity, and sustainable economic growth and clean energy development.

Q. How do PGE's proposals in this case balance the needs of all customer classes?

A. PGE's proposals in this docket refine cost of service allocations and customer commitments to better align growth-driven costs with those customer classes that are contributing to system peak growth. We recommend specific adjustments to PGE's marginal cost studies and minimum demand charges to align cost causation principles while recognizing system beneficiaries.

Q. What does PGE request of the Commission regarding its proposals?

A. We request that the Commission adopt PGE's proposals for addressing the addition of new large loads to its service territory and direct PGE to file an updated compliance filing to implement the marginal cost studies adopted in this investigation. The following is a summary of positions we are presenting in testimony that we request the Commission act on and the action we request they take:

- Approve the creation of Schedule 96 in compliance with HB 3546
- Reduce the threshold for the Large Load Customer Agreement (LLCA) from 30 MW to 20 MW to align with HB 3546
- Increase the minimum term length for LLCA from 8 years to 10 years to align with HB 3546
- Approve the proposal to move from volumetric to demand-based recovery of fixed generation costs for industrial customer classes.
- Adopt PGE's proposed Distribution Marginal Costs update for substations.
- Adopt PGE's Peak Growth Modifier for Transmission Marginal Cost (TMC) and Generation Marginal Cost (GMC)
- Approve the introduction of a minimum Generation Demand Charge (GDC) for customers subject to Large Load Capacity Agreements (LLCA)
- Approval of the approach under which large load data centers can pay for generation and related costs pursuant to Schedule 96, under the terms approved in this docket or a

special contract approved by the Commission individually if the terms and conditions vary from the approved schedule, or a combination of these two approaches

- Adopt the addition of Contributions in Aid of Construction (CIAC) for distribution assets

Q. Does PGE propose implementing these changes at the conclusion of this docket?

A. Yes. We propose implementing these changes prospectively through updates in PGE's retail tariff and a Commission order requiring PGE to make a compliance advice filing changing rates to reflect the changes outlined in PGE's proposals in this docket. Without such an order from the Commission requiring a compliance filing to change rates, any marginal cost principles adopted in this docket would not take effect until PGE's next general rate case. We see no reason for such a delay in implementation, particularly when PGE is seeing robust demand from large load customers.

II. Data Center Rate Class

Q. How does PGE's proposal for a new data center rate class align with the directives of HB 3546?

A. PGE's proposal to create a new data center rate class, Schedule 96, is aligned with the language in Section 2.2 of HB 3546, which directs utilities to "provide for a classification of service under ORS 757.230 for retail electricity consumers that are large energy use facilities."[1] Further, the bill clarifies that "the classification of service must be separate and distinct from classifications of service for other commercial or industrial retail electricity consumers and have its own tariff schedule."[2] New Schedule 96 is designed such that these requirements are met.

Q. Does PGE's proposed Schedule 96 comply with all elements of HB 3546?

A. Yes. HB 3546 provides that tariff schedules must do three things. First, it must either (i) allocate the costs of serving the data center class of customers 20 MW or over to the class in a manner that is equal to or proportional to the costs of serving the class or (ii) directly assign the cost of serving a member of the data center class to the class member. Second, it must mitigate the risk of shifting cost in an unwarranted manner or other classes paying unwarranted costs. Third, the rate class must meet any other conditions the Commission may require in the public interest when it reviews customer contracts with data center class members under the law. At present, the Commission has not set forth any requirements that are required in the public interest under the law, so the primary requirements applicable to the large data center rate classification concern appropriate and proportional allocation of the cost

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[1] House Bill 3546 Section 2.2
[2] *Ibid*

to serve the members of the rate classification and mitigating the risk of unwarranted shifting of cost to other classes of electricity customers.

Q. What parts of PGE's proposal are designed to ensure that costs are appropriately allocated to the large data center rate classifications and costs are not shifted in an unwarranted manner to other classes of customers?

A. The changes we propose to PGE's distribution, transmission, and generation marginal cost studies are expressly designed with this purpose in mind. Specifically, we propose greater detail in estimating the marginal cost of a substation to recognize the higher price of an industrial substation, versus substations that serve commercial and/or residential customers.

PGE has adjusted the methodology for its marginal cost study to incorporate a Peak Growth Modifier, which PGE details in Section III-B of testimony, that adjusts the allocation of transmission and fixed generation costs toward customer classes that are contributing most to system peak *growth* in recent years, not simply their contribution to the system peak for the target year. The intent is to reflect in our cost allocation methods the differences between investments for overall system maintenance and HB 2021 compliance versus those motivated by system expansion needs. The outcome is that customer classes contributing to PGE's system peak growth, like PGE's new large data center class and to a lesser extent, the residential class, will be allocated costs based on growth and size and not simply size[3]. This approach insulates customer classes that are not contributing, or contributing less, to overall system peak from unwarranted contributions to growth investments.

PGE's proposed changes to marginal cost studies build on other aspects in Rules C and I, such as minimum or flat demand for distribution, transmission, and generation, exit fees for

[3] Size in this context refers to the 12-month and 4-month average contributions to system peak used in transmission (12-CP) and fixed generation (4-CP) cost allocation.

distribution costs, and customer credit requirements, all of which work to mitigate the risk of unwarranted cost shifts.

Q. How did PGE identify customers to include within Schedule 96?

A. Using customer data, PGE identified customers with similar attributes consistent with the intent of HB 3546 and the Commission's general authority to create customer classification based on attributes that are relevant to the cost and terms and conditions for providing relevant services. Namely, customer facilities over, or able to be over, 20 MW in size engaging in business consistent with that of a data center, as defined in Section 2(c) and Section 2(d) of the bill.

Q. How many of PGE's current customers were identified and from which schedules were they moved?

A. There were five customers accounting for sixteen total service points identified that now make up the new Schedule 96 and its direct access equivalents consistent with the 2025 test year. Seven service points were moved from Schedule 89 and two from Schedule 90 to Schedule 96. In addition, seven service points across three of the five customers would be moved between Direct Access schedules, from Schedules 489 (4) and 689 (3) today to Schedules 496 and 696 if approved. Table 3 provides a crosswalk of the schedules these customers are currently on and the schedule they will be moving to.

Table 3
Existing Customers Eligible for New Rate Class

Customer	Current Rate Schedule	New Rate Schedule	Count of SPIDs
A	90	96	2
B	89	96	1
	489	496	1
	689	696	2
C	89	90	1
D	89	96	3
	689	696	2
E	89	96	2
	489	496	2
Total			**16**

Q. What other steps did PGE take to allocate costs to customers in Schedule 96?

A. To ensure that costs allocated to customers in Schedule 96 reflect their actual contribution to system usage and costs, which supports fairness, transparency, and long term-cost stability, PGE took several steps:

First, we identified the appropriate customers for Schedule 96 and moved their energy and demand values out of Schedules 89 and 90. We then used detailed customer usage data to isolate Schedule 96's contribution to the monthly system peaks. This allowed us to allocate marginal unit costs to Schedule 96 based on the specific system impact of the class, and to assign a proportional share of the functionalized 2025 revenue requirement to this new rate class.

Importantly, we did not update 2025 marginal unit prices for generation in this filing. Instead, we applied the unit prices previously approved in Docket UE 435 to the revised usage quantities that reflect the addition of the new class. This approach holds unit costs constant, helping to isolate the impact of cost-allocation methodology changes—ensuring that observed pricing impacts stem from the creation of Schedule 96 rather than from broader price adjustments.

For transmission and distribution, however, full updates to the marginal cost studies were necessary. These had not been refreshed since our 2024 rate review (UE 416), and the proposed distribution methodology includes the development of differentiated substation costs by class—an important refinement that improves cost accuracy across all classes.

For customer-related marginal costs, PGE did not update the underlying costs used in our UE 435 approved study, rather we re-allocated the 2025 unbundled revenue requirement for billing, metering and uncollectibles among all customer classes, including Schedule 96, resulting in revised unit costs for these elements.

These steps are essential to aligning costs with cost causation. By reflecting system usage and peak contributions, this approach helps ensure that each customer class pays its fair share, supports long-term system planning, and avoids cross-subsidization. The result is a more accurate and equitable foundation for rates—one that benefits the entire system and all customers, not just those in the new class.

Q. Going forward, how will PGE determine if a new large load customer should be included in this schedule?

A. If a new or existing customer who meets the definitions in our proposed Schedule 96 makes a reservation request for a total of 20 MW or more, they will receive service under Schedule 96. Though a customer may not initially take service at 20 MW, in order to avoid excessive rate migration and to ensure that these customers take service on the proper schedule, they will be placed on Schedule 96 if their request is for service at or above 20 MW.

III. Marginal Cost of Service

Q. What role do marginal cost of service studies play in the creation of rate design?

A. Marginal cost of service studies provide a forward-looking assessment of the incremental costs a utility incurs to serve an additional unit of demand—such as the need for new distribution, transmission or generation capacity. These studies are foundational to cost-based ratemaking because they identify which customer classes are driving both current and future system costs. This alignment promotes transparency, supports efficient decision-making by customers, and helps avoid unreasonable cost shifting between classes. From a system-wide perspective, marginal cost studies also help guide long-term investment and resource planning by sending more accurate price signals. By tying rates more closely to incremental system costs, utilities like PGE can support responsible growth, improve system efficiency, and maintain affordability and fairness for all customers.

In this docket, our use of marginal cost principles reflects a commitment to equitable cost allocation—particularly as new, large loads with distinct system impacts emerge. A strong marginal cost framework ensures that rate design evolves with the grid, while continuing to protect the integrity of the system and the interests of all customers.

Q. What are PGE's key objectives in revising its marginal cost studies for this proceeding?

A. In addition to following traditional cost causation, marginal cost principles, our proposed changes are design to more accurately align revenue responsibility with the customers classes driving the need for new system investments, particularly in generation and transmission infrastructure. As the system grows and evolves, traditional peak contribution methods require adjustments to properly allocate costs to, and reflect the impact of, rapidly growing load classes.

Our revised approach introduces an adaptable, scalable methodology because it focuses on contribution to peak growth—that is, how different customer classes contribute to the system's evolving peak over time, rather than at a single point in time. This distinction is critical: a class with fast-growing demand may not dominate today's peak, but it may be driving the need for new capacity and long-term investments.

By capturing this dynamic, our updated methodology ensures costs are allocated more equitably, sends more accurate investment signals, and supports a system that remains both reliable and affordable. It reflects PGE's commitment to modernizing rate design tools in ways that keep pace with system realities, while avoiding the long-term consequences of misaligned cost recovery.

Q. What did you consider as you reviewed and analyzed options for altering your current methods within marginal cost of service studies?

A. In reviewing options for altering our marginal cost of service methods, we prioritized approaches that uphold the Bonbright principles—particularly fairness in cost causation, customer understanding and administrative simplicity. We aimed to maintain a system-level view of generation and transmission, recognizing that these assets serve all customers. At the same time, we sought to ensure that costs are allocated fairly to the customer classes driving the need for new infrastructure—primarily those contributing to system peak growth—while minimizing unjust discrimination or cross-subsidization. It is important to preserve a method that reflects real-world system investments and operational needs, sends accurate price signals, and supports integrated planning. Lastly, we made our best efforts to avoid unnecessary complexity in any changes adopted.

Q. How do PGE's proposals support solutions approved in UE 430, mentioned above?

A. Our updates to marginal cost allocations assign more shared costs that are growth-driven, rather than policy or maintenance driven, to customer groups that are driving growth in peak demand. This means that higher-growth rate classes will pay a larger share of growth-related costs, even if they're not the biggest users today, or in the test year. In addition, our proposal includes a minimum generation demand charge to all new large load customers that helps us recover fixed investment costs more quickly, which reduces the risk of stranded assets over time. All of these changes are consistent with and build on our proposals in UE 430, which were intended to appropriately allocate connection costs of new large load customers through a variety of tariff changes and contractual terms and conditions. Unlike our UE 430 proposals, some of the changes we propose in this docket would change the underlying rates and allocation of costs to different rate classes.

A. Distribution Marginal Cost

Q. What change is PGE proposing to distribution marginal cost?

A. PGE is proposing to estimate and apply differentiated substation marginal costs by customer classes, rather than using a single, system-wide estimate. In previous studies PGE estimated and applied one generic substation design—based on two 35MVa transformers—to all customer classes, resulting in uniform $/kW substation costs. This approach did not account for the significant differences in the way various customer classes use distribution infrastructure. Our proposed change aligns substation cost estimates with the distinct service requirements of each class, resulting in a more accurate, cost-reflective allocation of distribution system costs.

Q. Why does PGE propose to apply different substation costs to different customer classes?

A. The cost to serve different types of customers varies significantly—particularly at the substation level. Recent engineering studies provided in Exhibit 104, show that a substation built to serve an industrial customer costs approximately 5.4 times more than one built for a typical residential neighborhood. Applying cost-causation principles to recognize these differences ensures that substation costs are more accurately and equitably assigned to the customer classes that drive them. This is necessary to modernize our cost studies in line with actual system usage and investment drivers.

Q. How do you calculate the marginal unit costs of substations?

A. We calculate substation marginal costs using updated engineering estimates for three distinct substation types: residential, commercial and industrial. For each type, we divide the total estimated costs by the substation transformer capacity in kW, then annualize the figure to derive a cost per kW marginal cost. This approach provides a more granular and accurate estimate of the cost to serve each customer class.

Q. How will these changes to the distribution marginal cost study impact customer prices?

A. The customer price impacts from this methodological change are modest and vary by customer class, depending on their use of substation infrastructure. These changes do not affect PGE's overall revenue requirement, but they do improve cost allocation fairness and better reflect system use. Customer class-specific price impacts are presented in this proceeding as percentage point changes relative to the outcomes of PGE's 2025 general rate review (UE 435).

Table 4
Distribution Marginal Cost Impacts from 2025

Customer Class	Substation Change Impact
Schedule 7	0.0%
Schedule 32	0.0%
Schedule 83	0.7%
Schedule 85	0.7%
Schedule 89	-0.9%
Schedule 90	-1.0%
Schedule 96	-1.0%

* Customer Impact Offset not applied

Q. Did PGE perform a full update to the Distribution Marginal Cost Study in preparation for this investigation?

A. Yes, a full update was completed. PGE did not perform a new Distribution Marginal Cost Study in PGE's 2025 general rate review because the distribution marginal cost study was roughly a year old at the time and any updates would not have materially changed allocations to the various customer classes. PGE has performed a new marginal cost study for this investigation since the underlying data from the previous study was pulled from PGE's system's two and half years ago. Aside from PGE's proposal calculating the substation costs to differentiate different customer classes, PGE used the same methodology to calculate distribution marginal costs as was used in PGE's 2024 general rate review, UE 416.

Q. What impact did the updated Distribution Marginal Cost Study have on customer prices?

A. The new marginal cost study had a modest change to allocations to customer classes because the underlying data has been refreshed based on updated material costs, with the exception of Schedule 85 whose marginal cost for Feeder Local Facilities had not been materially updated since 2016. Table 5 provides the impact to customer prices based on the updated study.

Table 5
Distribution Marginal Cost Impacts from 2025

Customer Class	Change Impact (Excluding Substation Change)
Schedule 7	-0.2%
Schedule 32	-0.2%
Schedule 83	-0.2%
Schedule 85	1.0%
Schedule 89	-0.1%
Schedule 90	0.0%
Schedule 96	0.0%

* Customer Impact Offset not applied

B. Generation and Transmission Marginal Cost

Q. What changes is PGE proposing to its generation and transmission marginal cost studies?

A. PGE proposes to introduce a Peak Growth Modifier (PGM) to separately allocate the costs of incremental fixed generation and transmission investments made in the three years prior to the test year—specifically those investments driven by system growth. Currently, PGE allocates fixed generation costs using a 4-CP allocation method and transmission costs using a 12-CP allocation method, both of which allocate costs based on class contribution to system peak for the target year. These methods, however, do not distinguish between customer classes that are driving current peak loads versus those driving growth in peaks over time. The PGM adds a layer that isolates the impact of peak growth—ensuring that the revenue requirement for growth-related investments is allocated to the customer classes most responsible for increasing the system's peak demand. This approach aligns more closely with cost causation principles, better reflects the realities of infrastructure planning, and supports a more equitable and efficient allocation of system costs as Oregon's electric grid continues to evolve.

Q. What is the PGM and how does it work?

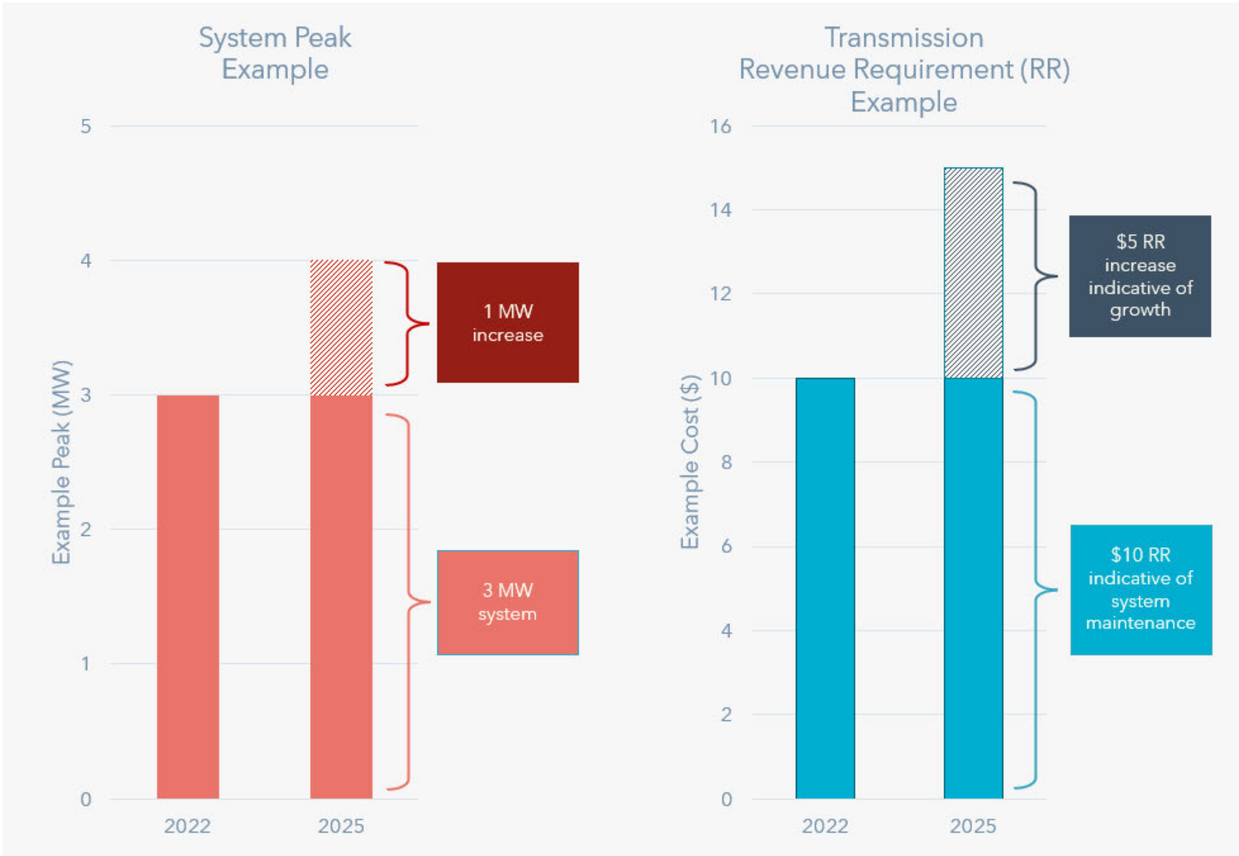
A. The PGM is a cost allocation methodology. It calculates class growth between two test years, measured in terms of average contribution to system peak (4-CP or 12-CP), as a percentage of overall cost of service system (henceforth referred to as system) peak growth during the same timeframe,

$$\frac{\Delta\ Class\ CP}{\Delta\ System\ Peak}$$

where the sum of class CP deltas is equal to the system peak delta.

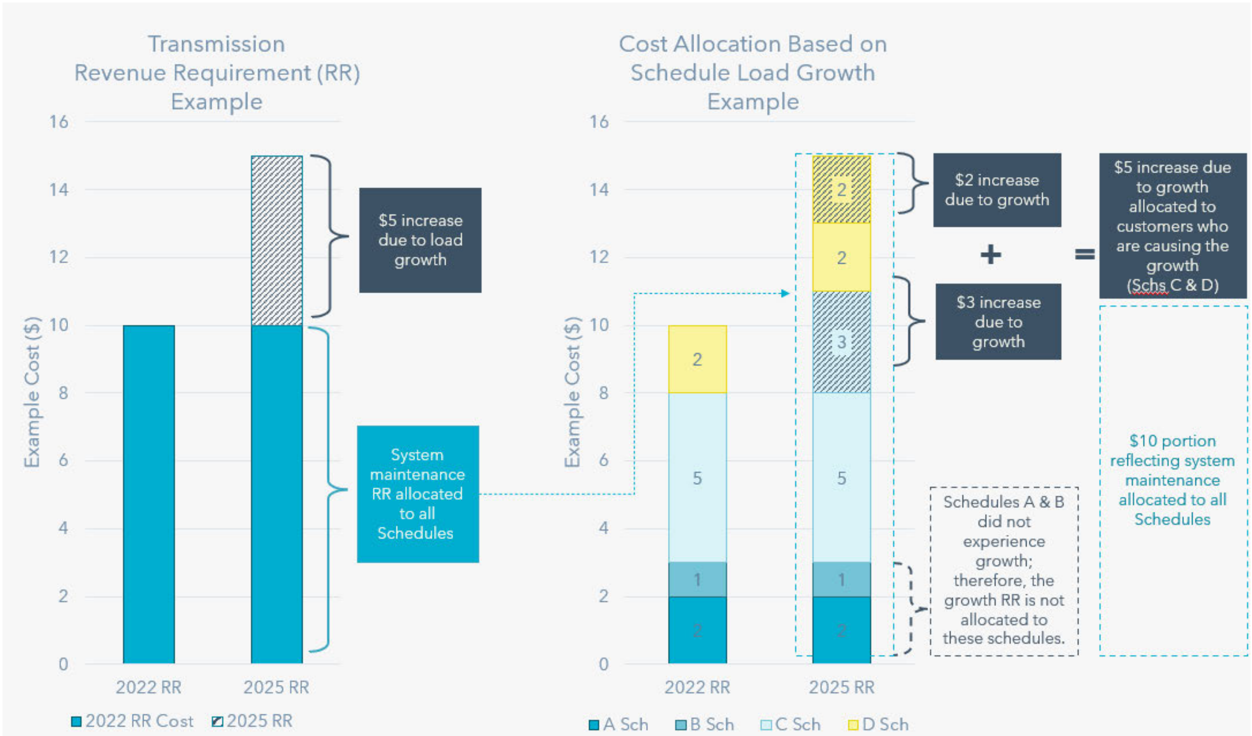
PGE proposes this allocation method be applied to the portion of fixed generation and transmission functionalized revenue requirements that are associated with growth-motivated investments. Specifically, PGE proposes a 3-year backward looking window for assessing both incremental revenue requirements that can be characterized as growth investments and the PGM components—system peak growth and class coincident peaks. The 3-year window smooths short term volatility and aligns cost allocation with actual investment drivers, avoiding distortions that could result in lumpy infrastructure investments or customer load additions or shifts in any single year.

The graphic below illustrates a simplified system-level of PGE's PGM proposal, where the 1 MW of system peak growth between 2022 and 2025 aligns with the $5 increase to the transmission revenue requirement during that period.



The following graphic shows the growth-driven $5 increase to the transmission revenue requirement is allocated specifically to the customer classes driving system growth (Schedules C and D) while remaining costs are allocated using PGE's standard 12-CP method.[4]

[4] The 12-CP method allocates costs based on each customer class's average monthly coincident peak.



Q. Will all generation and transmission investments for the previous three years have the PGM applied?

A. No. The Peak Growth Modifier is applied only to growth-driven investments—those specifically made to meet increased system demand. Many generation and transmission investments made in the three years prior to the test year are unrelated to load growth and instead address other essential needs, such as asset retirements and replacements, system hardening or compliance with policy mandates like HB 2021. These are investments PGE would make regardless of customer load growth and are allocated to customer classes using the typical 4 or 12-CP methodology consistent with long standing regulatory practice.

Q. Can you provide an example of an investment that would be subject to the PGM and an investment where it would be inappropriate to apply the PGM?

A. The Constable Battery Energy Storage System is an example of an investment made to ensure additional capacity was available to serve growth in peak periods reliably and would thus be subject to the PGM. Whereas the Wheatridge Wind Project is an example of an investment PGE made that was not related to peak load growth, but was instead made to ensure PGE has sufficient clean energy to serve all customers after the retirement of the Boardman Coal Plant in 2020.

Q. How does this method address cost shifting and support the fair allocation of costs between customer classes?

A. The Peak Growth Modifier (PGM) enhances fairness in cost allocation by introducing a dynamic, growth-sensitive approach to assigning generation and transmission costs—ensuring that customer classes driving peak growth are more accurately assigned the costs of the infrastructure built to serve them. Traditional CP methods offer a static, single-year snapshot of peak contributions in the target year. The Peak Growth Modifier adds critical nuance by measuring customer class growth over time, providing a more robust reflection of cost causation, especially in rapid load change. This flexibility applies both to the influence of the PGM in overall transmission and fixed generation allocations, as well as class allocations within the PGM. The PGM is also responsive to system conditions.

In the near future, when significant investment and purchases are needed to meet increasing load expectations, a larger portion of transmission and generation revenue requirement will be allocated using the PGM as compared to typical coincident peak methods. In periods of slower growth and proportionately less spending on growth-related assets, the PGM would have less influence on cost allocations.

Considering class-level allocations within the PGM, the methodology accounts for a range of growth contribution scenarios. If one customer class is driving 100% of system peak growth, that class would be allocated 100% of growth-related revenue requirement for the first few years the asset is in service, somewhat akin to direct class assignment but for a period of time. If all customer classes are growing at the same rate (such that their proportional contributions to system peak are constant), the PGM would allocate growth-related revenue requirement in the same manner as 12-CP or 4-CP and have no incremental influence on class allocations. The Company forecasts indicate that two customer classes are currently contributing most to system peak increases—the new data center class, due to its rapid expansion, and the residential class, which despite modest growth, has such a large base that results in significant absolute increase in peak demand.

Our proposal of a PGM, in combination with minimum demand requirements for large load customers and exit fees, helps ensure that COS allocations are better balanced, forward looking and aligned with actual system impacts. It reduces the risk of cost shifting and supports more sustainable and equitable rate structures across all customer classes.

Q. What impact does the PGM have on Customer prices?

A. Table 6 below illustrates the resulting impacts by customer class.

Table 6
PGM Marginal Cost Impacts

Customer Class	Transmission PGM Impact	Generation PGM Impact	Combined PGM Impact
Schedule 7	-0.4%	0.0%	-0.3%
Schedule 32	-1.3%	-0.7%	-2.1%
Schedule 83	-1.3%	-0.7%	-1.9%
Schedule 85	-0.5%	-0.6%	-1.1%
Schedule 89	-1.2%	-1.6%	-2.7%
Schedule 90	0.4%	-0.1%	0.3%
Schedule 96	11.1%	7.7%	18.9%

Q. Why is the measurement of the contribution to system peak growth the right measurement for ensuring fair allocation of costs?

A. Measuring each customer class's contribution to system peak growth is essential for fairly allocating the costs of infrastructure investments needed to serve rising demand. A class's share of system peak in a single year tells only part of the story—what matters for cost causation is which classes are driving growth in that peak over time, which is what ultimately triggers the need for new generation and transmission resources.

For example, over the past three years, the residential class, while showing only modest growth in relative terms (in terms of 4-CP, the class increased by about 6%), it accounted for 45% of the growth in system peak during the four highest use months. Customers eligible for Schedule 96, which currently represent just 4% of the system peak during the four highest use months, have grown five-fold since 2022 and contributed 54% to total system peak growth during the same period. Together, these two classes (Schedule 7 and 96) have been the primary drivers of the recent growth in system peak.

Relying solely on forecasted peak contributions would place most of the incremental costs on residential customers and under-assign costs to Schedule 96. Allocating new costs based on class contribution to system peak growth instead yields a more equitable and efficient cost structure. If PGE were to solely allocate all new costs to Schedule 96, they would bear an unfair burden because they are not the only contributors to the growth in the system peak. Table 7 shows the calculations and contributions of rate classes to system peak growth, in terms of 12-CP and 4-CP, over the 2022-2025 period.

Table 7
Class Contributions to System Peak

Class Contributions to Average Monthly System Peak (12-CP)				
Customer Class (Rate Schedule)	**2022**	**2025**	**2022-2025 Growth**	**2022-2025 Percent of Growth**
Schedule 7	1,523	1,600	77	34%
Schedule 32	256	249	-6	-3%
Schedule 83	458	457	0	0%
Schedule 85	392	403	11	5%
Schedule 89	80	74	-6	-3%
Schedule 90	355	387	32	14%
Schedule 96	22	146	124	54%
All other schedules	25	23	-2	-1%
COS Coincident Peak	3,111	3,340	229	100%
Class Contributions to Four Highest Monthly System Peaks (4-CP)				
Customer Class (Rate Schedule)	**2022**	**2025**	**2022-2025 Growth**	**2022-2025 Percent of Growth**
Schedule 7	1,791	1,901	110	45%
Schedule 32	279	268	-11	-5%
Schedule 83	483	479	-4	-2%
Schedule 85	402	408	6	2%
Schedule 89	78	72	-6	-2%
Schedule 90	357	386	29	12%
Schedule 96	21	142	120	50%
All other schedules	30	29	-1	0%
COS Coincident Peak	3,442	3,685	243	100%

Q. Did PGE perform a new Transmission Marginal Cost Study for this investigation?

A. Yes. PGE performed an updated Transmission Marginal Cost Study for this investigation because for the same reasons as the Distribution Marginal Cost Study, it was not revised in UE 435. Aside from PGE's proposal to apply a PGM to differentiate customer classes and the addition of the new data center rate class, PGE used the same methodology to calculate transmission marginal costs as was used in UE 416.

Q. Is PGE proposing the direct assignment of any transmission or generation costs?

A. No, PGE is not proposing to directly assign PGE transmission system or generation costs for assets procured for general cost of service. However, PGE is proposing consistent with

HB 3546, that large load data centers have the opportunity for direct contracting for the cost of service, including generation and capacity resources through power purchase agreements or owned assets, pursuant to a Commission-approved special contracts schedule or subject to Commission approval if the terms and conditions vary from the Commission-approved schedule (see Section VI below for further details).

Q. Why isn't PGE proposing the direct assignment of costs for transmission and generation assets to specific customer classes?

A. PGE is not proposing to direct assign the costs of transmission or generation assets to any single customer class, for reasons grounded in both regulatory fairness and system functionality as described below.

As an initial matter, it is important to distinguish between direct assignment and direct contracting. "Direct assignment" refers to allocating the costs of a particular asset to a customer class within PGE's ratemaking model. "Direct contracting" refers to special contracts where a specific customer (or group of customers) agrees to directly procure and pay for an asset outside the general cost allocation framework.

PGE is not proposing to directly assign costs for specific transmission and generation assets to any one customer class for two primary reasons. First, transmission and grid-connected generation resources are network system assets intended to serve all customers, not individual customers or customer classes. Second, implementing direct assignment for network resources is unworkable and inappropriate. Allocating an individual asset that is a network resource to a particular customer class or classes does not represent the physical reality of how the system operates nor the regulatory principles of cost causation and benefit distribution. Further, if one asset were assigned to a customer class, the utility would have to track all future investments, depreciation and cost of removal for each asset individually assigned. Additionally, the forecasted energy and demand requirements for that class would need to be adjusted in the larger cost allocation model such that the class is fairly allocated other system generation and transmission costs. Both of these tracking and estimation requirements add unnecessary complexity and burden, particularly for utilities calculating group depreciation.

If one set of customers seek to push all the cost of shared system costs unto one customer class, there is no reason other customer classes will not make the same type of arguments for other system resources that are driven by other customer classes. For example, distribution costs in urban areas undoubtedly are more associated with residential customers than industrial or data center customers. If the cost of network upgrades that benefit and serve all customers are allocated exclusively to large data centers, then data centers could argue that the cost of distribution system should be exclusively assigned to residential customers. The outcome of such fragmentation of the network is uncertain given that the arguments in favor of such a misguided approach go both ways and will not stop with attempts in this context to assign all such grid improvement costs to a large data center customer class. Finally, the assumption underlying these arguments for fragmentation is unfounded: loads for residential customers are growing and contributing to peak growth.

Q. As PGE is at the forefront in this space, what else have you considered as you support your new approach to marginal cost and rate design?

A. PGE's updated approach reflects a forward-looking, principle-based response to a rapidly evolving system. We recognize that while data centers are a significant contributor to near term system growth, as shown in Table 7, they are not the only ones. Residential and commercial load growth, electrification, and evolving end-uses (like EVs and heat pumps) are all expected to increase over time. Importantly, future growth may also come from other customer classes for whom special contractual arrangements would be impractical. Relying solely on direct contracts is therefore not a comprehensive solution as they cannot substitute class-based allocation frameworks for certain investments. Developing a marginal cost and rate design model that adjusts the allocation of future investment costs toward the classes driving that growth—using our Peak Growth Modifier—offers a fair, sustainable approach that can endure over time.

Q. Does the PGM approach to allocating costs of growth reflect the impact of energy efficiency on class peaks?

A. Yes, the PGM method is based on historical growth in class peaks and as such reflects the actual implementation of energy efficiency measures by class. PGE is performing additional research into the relative class contributions of the cost of energy efficiency.

C. Customer Marginal Cost

Q. Is PGE proposing any changes to the customer marginal cost study in this proceeding?

A. Yes, PGE is proposing the inclusion of new Schedule 96 in the customer marginal cost study that was approved in UE 435.

Q. Is PGE proposing any additional changes?

A. No. Because of the nature of the customer marginal cost study, there are no changes, apart from the addition of Schedule 96, needed in this docket. These customers will utilize already existing services and at this time, they are not driving substantive growth in costs contained in the customer marginal cost study. In future rate proceedings, we will continue to evaluate how customer classes are utilizing customer service resources, but no substantive changes are needed at this time.

IV. Rules C and I

Q. What changes to Rules C and I were established in UE 430?

A. Primarily, Rules C and I changed to create new customer classifications for new customer load requests. The changes also instituted a new contract process for customers with requested capacity greater than 30 MW, created new credit requirements, minimum transmission demand requirements, capacity exceedance penalties, distribution demand requirements, exits fees, and specified a process for system capacity reallocations. The Rule C change introduced the prohibition of load banks to temporarily increase load to meet minimum load or demand levels.

Q. Is PGE proposing any changes to the categories currently in Rules C and I?

A. Yes, to align with the standards set in HB 3546, PGE is revising the categories in Rules C and I from 30 MW to 20 MW. Provisions specific to data center customers will be present in Schedule 96 while the terms in Rules C and I will be applicable to all large customers, regardless of industry.

Q. Is PGE recommending any other changes to Rules C and I from where we landed in UE 430 at this time?

A. UE 430 only discussed transmission and distribution. PGE is aligning the work to match, where necessary, HB 3546. PGE is also making a recommendation to add a minimum generation demand of 80%, in concert with our proposal to introduce generation demand charges for all industrial customers, since generation was not discussed in UE 430. PGE is also proposing a few minor adjustments to the existing rules for clarity. Additionally, PGE is considering updates to customer agreements required under Rule I and Schedule 96 to reflect the impact of generation on the forecasted in-service date. We are not currently recommending any additional changes to Rule C.

Q. What minor changes is PGE proposing?

A. PGE is proposing that load requests under 4 MW (1.0 MW to 3.99 MW) be charged a flat rate for Feasibility, System Impact, and Facilities Studies. Requests of this size are typically less complex than larger requests and PGE can utilize historical data to set these rates and update annually, as needed. This will provide certainty for these smaller, yet highly important, customers in this segment. In addition, this will greatly reduce administrative efforts for both PGE and the Customer which will result in a more streamlined process for the Customer. All requests 4.0 MW and greater will maintain the current practice of a flat administrative fee and prepayment that is trued up with the actual costs following the conclusion of the study. PGE Exhibit 105 provides a redline copy of Rule I.

A. Distribution Features

Q. What distribution features are currently reflected in rule I?

A. In UE 430, PGE introduced the concept of a flat billing demand for customers subject to a large load customer agreement (LLCA). Billed Demand recovers PGE's annual revenue requirement in every year of the connecting customer's contract, guaranteeing that 100% of the costs for the necessary distribution investments are paid by the connecting customer. Charging a customer a flat value for Billed Demand, rather than billing based on actual demand, mitigates the potential risk of not recovering the annual cost to provide the infrastructure investment and associated expenses, or the full revenue requirement, if the customer's actual demand is too low, thus fairly assigning costs to the customer and mitigating risk to other customers.

Q. What changes are you recommending to ensure alignment with HB 3546?

A. We are updating the minimum contract term from 8 years to 10 years to align with HB 3546. No other modifications are necessary to comply with HB 3546.

Q. Are you recommending any other changes?

A. No.

B. Transmission Features

Q. What are the current features for transmission?

A. In UE 430, PGE instituted several changes to system capacity allocation. These included an updated system capacity study, a queueing and capacity allocation process, exceedance penalties, capacity allocation renewal terms, a refundable capacity allocation deposit, and a minimum transmission demand charge. These changes were approved and in place beginning April 16, 2024, with customer agreements signed in the interim being subject to change based on the final Commission order in UM 2377.

Q. How did PGE determine the 80% Minimum Transmission Demand standard?

A. PGE based the 80% Minimum Transmission Demand standard on the load factor for Schedule 90, which should be reflective of new large load customers. 80% strikes a balance between the need for cost recovery with the fact that transmission is a system resource. We also looked at other utilities that are developing large load or data center specific tariffs to verify that this standard was in alignment with the broader regulatory landscape.

Q. How is this standard consistent with cost causation principles and why is it preferable to 90%?

A. PGE's proposal is informed by the need to balance appropriate cost recovery and risk mitigation with avoiding undue cost burdens on new large load customers and ensuring they are treated equitably. It is unlikely that a customer will use 100% of their allocated system capacity and this, coupled with the fact that transmission is a system resource and that we have not employed minimum transmission demands in the past, makes 80% a better balance of these factors than 90%.

Q. Please provide the purpose of the system capacity allocation deposit and why the amount was chosen.

A. We created a system capacity allocation deposit as a mechanism to reduce speculative load requests and encourage customers to make thoughtful, realistic assessments of their capacity needs. Like many other of the provisions proposed in UE 430, this mechanism aims to balance the interest of all customers by supporting orderly system planning and resource procurement without creating unnecessary hurdles for new large load customers. In addition to encouraging accurate load requests, the deposit reinforces a commitment to take service and meet any associated flexible resource requirements.

Q. Why is the deposit refundable and how did PGE determine the length of the payback period?

A. The deposit is refundable because it is meant to ensure that the customer meets their obligations to come onboard the system and meet any associated flexible resource commitments, if applicable. If a customer meets their minimum transmission demand requirements, there is no need to retain the customer's deposit. PGE set the length of the payback period to be consistent with the initial three-year term of the system allocation contract.

Q. What is PGE's exceedance penalty?

A. PGE's exceedance penalty is 4 times the tariff transmission rate multiplied by the actual demand minus the exceedance threshold per hour. The exceedance penalty will take effect if the customer's demand exceeds their Transmission Reserved Capacity by the lesser of 5 MW or 10% of Transmission Reserved Capacity.

Q. Why is there a buffer for the exceedance penalty?

A. There is a buffer for the exceedance penalty because we acknowledge that there is some room for load fluctuation on the system and we plan for it, so it is not appropriate to immediately penalize the customer for exceeding their allocated load within whichever is the lesser of 5 MW or 10% of Transmission Reserved Capacity.

Q. How did PGE determine the appropriate rate for the exceedance penalty?

A. PGE designed the exceedance penalty rate to serve as a strong disincentive against customers exceeding their contracted load during a period of high system utilization. If a customer exceeds their contracted load when the system is at full capacity, the system can become unstable and place it at increased risk of localized outages. Because the precises costs and operational consequences of such exceedances are difficult to quantify in advance, a clearly defined and firm penalty rate provides a necessary signal to encourage customer to remain within their contracted limits and helps safeguard system stability.

Q. Is PGE still recommending an Enhanced Planning Area (EPA)?

A. PGE is not making any changes to our definition and application of Enhanced Planning Areas. The applicability of an EPA in the tariff is only related to the load study process criteria.

Q. Is PGE proposing changes to any of the transmission features discussed in UE 430?

A. Yes, PGE is actively considering options that mitigate the near-term financial risk from customers who exit before they have satisfied certain contract terms while continuing to enable all customers to benefit from the addition of transmission system assets. PGE is considering an exit fee for transmission but needs additional time to ensure that the proposed solution adequately balances equity for all customers with the risks and benefits of system investment. PGE is also analyzing the conditions under which allocated system capacity could be reduced at Company discretion to ensure we are striking an appropriate balance for new large load customers and existing customers.

C. Generation Features

Q. What does PGE propose regarding a generation demand charge?

A. We are proposing an expansion of generation demand charges to COS customers on Schedules 89, 90 and 96. Currently, only Customers on Schedules 83 and 85 have generation demand charges. Expanding this rate design structure to the other large commercial and industrial schedules will create design consistency from customers who migrate rate schedules as they grow.

Q. Is PGE proposing a minimum demand charge for generation?

A. Yes, consistent with PGE's approach to transmission, we are proposing a minimum generation demand charge based on 80% of the customer's reserved capacity. This aligns well with the transmission features of PGE's proposal in UE 430.

Similar to the minimum transmission demand charge proposed in UE 430, a minimum generation demand charge of 80% ensures customers who are allocated system capacity are using it and reasonably paying for generation costs.

Q. Is PGE concerned that adding a minimum demand charge for generation will be redundant to the minimum transmission demand charge?

A. No, these demand charges apply to different functional areas. Adding a minimum generation charge serves to mitigate the near-term risk of underutilized generation assets that were procured to serve a new large load customer that exits early. Transmission and Generation assets have different functionalized costs so there is risk associated with each that is not covered by the other.

Q. Is PGE considering an exit fee for generation?

A. We have not ruled out the possibility of a generation exit fee, but much the same as transmission, generation has a system benefit, and this benefit should be evaluated when considering whether an exit fee is appropriate or required. We are currently in the process of evaluating an appropriate exit fee and look forward to reviewing other parties' testimony and addressing this issue in later rounds of testimony.

V. Contributions in Aid of Construction

Q. What does PGE propose for Contributions in Aid of Construction?

A. As an option, we are offering new large load customers the ability to make a 50% Contribution in Aid of Construction (CIAC) toward the cost of their dedicated distribution infrastructure. This approach reflects a practical response to current system investment needs and allows us to balance cost recovery with customer preferences. Importantly, we are maintaining the flexibility to fully fund distribution assets ourselves, as we have traditionally done, for large customers who prefer not to contribute capital up front.

Q. PGE opposed allowing for CIAC in UE 430. Why is PGE offering a CIAC now?

A. While we have historically opposed CIACs to preserve cost-based equity, this optional structure is designed to provide greater customer choice while continuing to ensure that investments remain aligned with long-term system value and ratepayer fairness. The 50% CIAC offering is intended to reduce capital constraints without mandating customer participation or shifting risk inappropriately.

Q. How would PGE's new proposal work?

A. If a customer chose the CIAC option, they would contribute 50% of the cost of the distribution facilities built for them before construction began. Customers opting into the CIAC would pay distribution demand charges based on the methodology currently established in Rule I where a fixed demand is established using the year one revenue requirement divided by the current distribution demand charge. These customers will also receive a credit commensurate with their contribution. This credit will be calculated in the same manner as the fixed demand charge, but the kW will be based on the revenue requirement of the contribution. The credit amount will remain fixed for the duration of the initial 10-year contract period and the demand charge will revert to actuals in year 11.

Q. Is the CIAC optional or mandatory?

A. PGE is proposing an optional CIAC. As established in UE 430, setting a fixed demand and exit fees mitigate the risk that other ratepayers will not be subject to unwarranted cost shifts associated with the construction of new assets while not placing unfair burden on new large load customers.

Q. Why would a customer select the CIAC option?

A. A customer might choose to select the CIAC option if they have funds available up front and would like to reduce the fixed portion of their bill each month. The CIAC is not meant to provide an incentive to customers, just an option for those who would rather pay up front and reduce the fixed amount they are paying each month.

Q. Why is PGE proposing a ten-year term?

A. A ten-year term is not a material change and aligns with HB 3546. This leads to a more streamlined, easy to understand experience for customers by keeping contract terms consistent across options.

VI. Direct Contracting for Resources

Q. How is PGE proposing to address the challenge of procuring sufficient generation resources for data center customers?

A. PGE is proposing a multi-path-solution that adheres to HB 3546 and gives large customers a range of choice while ensuring reliability, fairness, and investment certainty. Eligible COS customers will default to Schedule 96. Customers will have the option to take service under Schedule 96 and opt not to enter any direct contracting (i.e. special contracts) for resources to serve their load. Alternatively, customers on Schedule 96 could choose to enter special contracts for resources to satisfy either some or all of their expected load.

For the portion of the service to be served under general COS, PGE will recover the cost of generation capacity needed to serve these customers through a generation demand charge. Growth-related generation procurement costs associated with serving COS data center load would be allocated to this rate class based on the PGM —ensuring the minimization of cost shifting to other customer classes.

For the portion of service customers elect to enter into a special contract, customers will be able to subscribe to all or a portion (if the resource is to be shared among multiple customers) of a new resource to directly serve their load. These contracts allow for targeted, timely procurement of resources that meet the specific needs of the customer(s) while shielding existing customers from any associated risks. Pursuant to HB 3546, any such special contract would need to be consistent with any Commission-approved schedule establishing terms and conditions for a special contract or approved individually if the terms and conditions of the special contract vary from the approved schedule, or if there is no Commission-approved terms and conditions applicable to special contracts.

Q. Please describe how these structures would be implemented in practice?

A. Data center customers opting for standard COS service would pay a generation demand charge under Schedule 96 that reflects the PGM allocated costs of serving data center load. PGE would procure resources through its integrated resource plan (IRP), but the costs would be allocated based on customer class growth to address cross-subsidization.

Customers electing to enter a special contract would work directly with PGE to structure a dedicated procurement pathway. These contracts may take the form of long-term off-take arrangement, where PGE purchases output from a clean or firm resource on behalf of the customer(s), or a PGE ownership model, where PGE develops or acquires a resource specifically for that customer's use. In either case, the customer(s) would bear the full cost of the resource, including energy, capacity, integration, and operational risks. Customers in this category may continue to use and pay for other generation and capacity related services depending on the type and quantity of resources procured through special contracts.

Q. How will PGE select and allocate generation resources for data centers under Schedule 96 versus those with special contracts?

A. For data center customers taking standard COS service under Schedule 96, PGE will include their projected load in our broader resource planning and procurement processes, such as IRPs and competitive RFPs. However, the key distinction is that the costs of growth-driven generation needed to serve customers will be assigned to that customer class based on their contribution to system peak growth—not spread across the rest of PGE's customer base that is not considerably contributing to system peak growth. While the resource itself may be part of PGE's system-wide portfolio, the financial responsibility for their portion of the new generation will rest with Schedule 96 customers through a generation demand charge or volumetric energy charge as it does for all other COS customers.

For customers who choose to enter into special contracts, to the extent that the customer has identified a specific resource it wishes to acquire, it may bring that forward to request PGE to negotiate and procure. Alternatively, PGE will work with the customer(s) to identify their specific resource needs—such as technology type, location, emissions profile, or timeline. In these cases, the selected resource may serve a single customer or a group of customers who subscribe to a defined share of a larger resource. The contract would define the percentage of capacity and energy assigned to the customer, with full cost recovery embedded in the special contract. Any such contracts would be executed pursuant to a Commission-approved special contracts schedule or submitted separately for Commission approval. This approach enables flexibility and speed to market while ensuring the resource is appropriately integrated into system operations and planning.

In both pathways, PGE maintains oversight of reliability, planning, and compliance. The financial and procurement structures are designed to match customer choice: pooled class-based procurement for COS service, or individualized cost-assigned contracting for those seeking a tailored solution.

Q. How will PGE treat transmission acquired or needed for resources procured through standard COS or through its direct contracts?

A. Delivering energy to PGE's system may require multiple segments of transmission lines.

Figure 31. PGE Transmission Concentric Circles

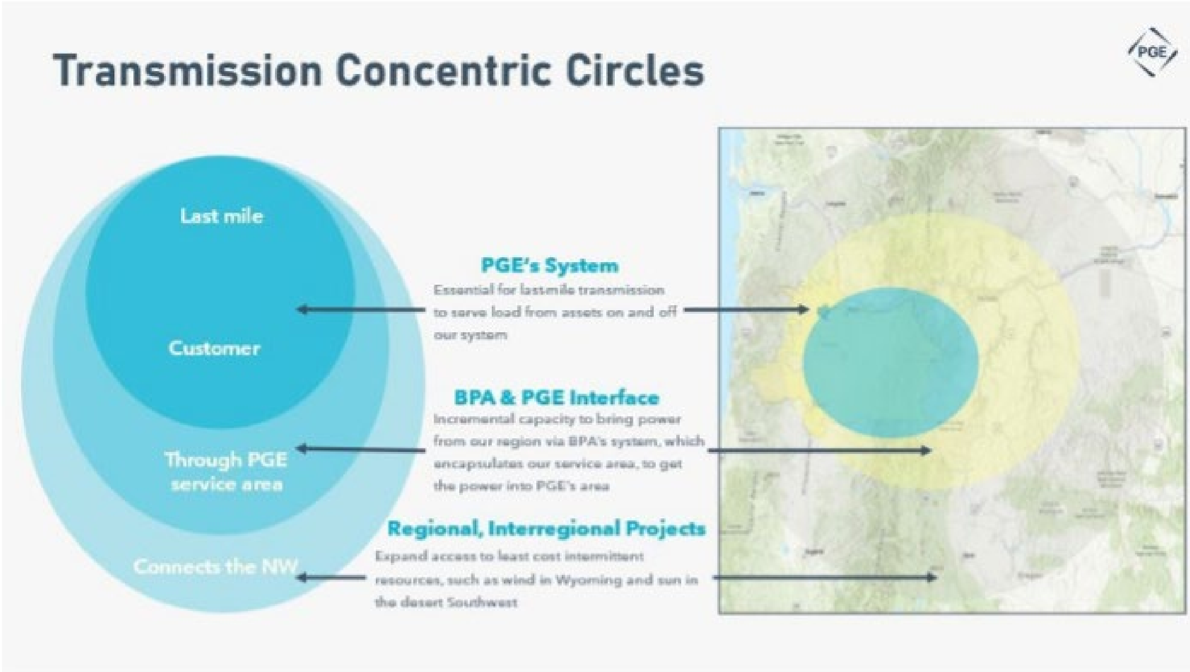


Figure taken from PGE's 2023 IRP/CEP Update. *For discussion within this testimony, PGE's System will be referred to as 'Circle 1', BPA & PGE Interface will be referred to as 'Circle 2' and Regional, Interregional Projects will be referred to as 'Circle 3'.*

PGE needs to ensure that the costs associated with the delivery of any generation project is treated in a manner consistent with the cost associated with the generation project itself. If a resource is acquired for COS under Schedule 96, the costs associated with Circle 2 and Circle 3 will go through the marginal cost allocation process, but if a resource is acquired under a special contract, any costs associated with Circle 2 and Circle 3 for transmission to deliver to PGE's system would be included in the costs charged to the customer under the special contract.

Q. How does PGE propose engaging in procurement for additional generation resources?

A. PGE's approach to both COS procurement and special contracting will remain grounded in transparency and regulatory oversight. For standard COS procurement—including resources serving Schedule 96 customers who do not elect a special contract—PGE will continue to follow the Competitive Bidding Rules under which resources are selected through a fair, transparent, and least-cost framework that protects all customers. The percentage of generation that was procured for peak load growth will be allocated based on the PGM. However, for customers who enter special contracts, PGE does not anticipate using a formal Request for Proposal (RFP). These contracts will be structured as bilateral agreements between PGE and the specific customer(s), designed to meet that customer's unique resource preferences, timing needs, or emissions goals. The resource is not intended to serve the broader system, and no cost is socialized to other ratepayers. Additionally, one primary purpose and intent of special contracts is to allow customers to receive service quicker than they may otherwise through COS. Formal RFP processes not only take additional time to acquire and contract for resources, but resources that will be acquired through RFPs will be allocated to all customers. That said, PGE will still ensure that pricing under special contracts is rooted in market conditions, and that the resource can be reliably integrated into the grid. The bilateral nature of these contracts allows for flexibility and speed, while clear cost assignment, exit provisions, and integration standards protect existing customers and maintain alignment with regulatory expectations for prudency and fairness.

Q. Why is bilateral flexibility in special contracts important for economic development and speed to market?

A. Bilateral flexibility allows PGE to respond to large customers, like data centers, on timelines that traditional RFP-based procurement cannot meet. These customers often have aggressive development schedules and unique resource needs, such as 24/7 clean energy or co-located generation. Special contracts let PGE tailor solutions quickly, helping Oregon remain competitive in attracting high-impact investments.

At the same time, all costs and risks are fully assigned to the contracting customer, ensuring existing COS customers are not negatively impacted by special contracts. This structure balances flexibility with fairness, enabling economic growth while preserving system reliability, regulatory integrity, and protecting other customers from unwarranted cost shifts.

Q. Under these special contracts, will PGE include the option to allow co-location of generation resources with large customers?

A. Yes, where technically and operationally feasible, PGE is open to co-locating generation resources with large customers under a special contract under Schedule 96. One of the core benefits of the special contract model is its flexibility—it allows PGE to tailor resource procurement and delivery structures to the specific needs of large customers, including co-location, without shifting cost or risk to other customers.

PGE recognizes that many data centers are increasingly interested in co-locating clean energy resources to meet sustainability goals, support reliability, or streamline permitting. When structured appropriately, co-location can help customers meet 24/7 clean energy targets, reduce transmission needs, and accelerate development timelines.

That said, any co-located resource would still need to meet PGE’s operational standards, interconnection requirements, and resource adequacy obligations. These elements would be addressed through the special contract to ensure the resource can be safely and reliably integrated into the grid. In short, co-location is an option PGE can support—provided it aligns with system needs and is fully customer-funded through the terms of the contract.

Q. Why not simply increase the cap on direct access to allow data centers to directly procure for generation?

A. While direct access is being examined separately in UM 2024, it does not address the immediate system planning, reliability, and cost-allocation challenges posed by new large loads. Under direct access, PGE remains Provider of Last Resort—even if the customer purchases energy elsewhere.

Special contracts offer a solution under UM 2377. They allow large customers to meet their specific procurement goals while enabling PGE to maintain load visibility, ensure planning alignment, and assign all appropriate costs and risks to the contracting customer. This approach supports timely, coordinated resource development—something direct access cannot guarantee in the near term.[5] This approach also allows PGE to be part of the solution to serve these customer's needs.

Q. How will PGE address resource adequacy within its special contracts?

A. PGE will structure special contracts to ensure that the contracted generation contributes to our overall resource adequacy obligations. This means customers entering into special contracts will be responsible for securing resources that meet PGE's planning criteria—such as firmness, deliverability, and capacity accreditation—or for covering the cost of supplemental resources if their chosen supply does not qualify.

These requirements will be embedded in the contract terms, ensuring that each customer brings sufficient capacity to the system or pays for PGE to procure it on their behalf. This approach maintains fairness, supports grid reliability, and ensures that the obligations created by data centers are fully met without impacting existing customers.

[5] Calpine Solutions 200/Higgins/page 7 -8

Q. How can this structure support PGE's efforts to achieve Oregon's clean energy and reliability goals in HB 2021?

A. The special contract framework directly supports the state's goals under HB 2021 by enabling PGE to procure clean, reliable resources tailored to large customer needs—without compromising affordability or compliance for existing COS customers. These contracts can be structured to include non-emitting or renewable generation, resource adequacy contributions, and integration services, all of which align with the planning, reliability and emissions reduction mandates in HB 2021.

For example, if a data center customer wishes to pursue a generation option—such as nuclear—that does not currently align with PGE's RFP eligibility criteria, a special contract offers a pathway to accommodate that choice without distorting COS procurement or increasing rates for other customers. In this way, special contracts provide both the flexibility to meet evolving data center customer preferences, and the control needed to ensure Oregon's broader energy goals are achieved equitably and reliably without shifting risks and costs to existing COS customers.

Q. What provisions would PGE propose to prevent cost-shifting under these special contracts?

A. The entire cost of the resource—including but not limited to development, energy, and capacity—will be borne by the contracting customer. Contracts will include binding commitments and exit provisions to prevent stranded costs from falling to other customers if the data center customer departs or scales back.

Under HB 3546, any such special contract will either need to be consistent with any Commission-approved special contract schedule or require Commission approval so the

Commission will have the opportunity to ensure that the contract terms and Schedule 96 fairly allocate the cost of serving the customers and that other customers are not subject to unwarranted cost shifting.

Q. How are PGE's proposed special contracts different from its Green Tariff offer under Schedule 55?

A. PGE's Green Tariff (Schedule 55) is a rider designed for COS customers who want to match their energy use with new renewable generation through a structured, subscription-based program.

Schedule 55 has proven to be a successful and valuable framework, and it has helped PGE better understand how to meet the clean energy preferences of large customers. However, data centers and other high-impact loads require a more flexible and tailored approach—particularly around resource selection, development timelines, and integration—given the need for the resource to effectively help serve their load. In addition, PGE's Green Tariff product under Schedule 55 is not intended to be a load-serving product but is intended to provide claims to bundled renewable energy credits from resources for which their direct contracting helped bring to PGE's portfolio. While the concepts and some of the structures under Schedule 55 can and should be used in special contracts for large load, changes and additional provisions to ensure COS customers are not subject to unwarranted cost shifts will be needed.

Special contracts are designed to meet those more complex needs. These individually negotiated agreements allow for custom resource types, dedicated procurement pathways, and faster execution timelines. This makes special contracts the appropriate tool for serving large, fast-growing customers that need energy solutions beyond the scope of existing tariffs.

Q. What is PGE's recommendation to the Commission?

A. PGE recommends that the Commission adopt a multi-path framework under UM 2377 that enables data center customers to be served either through a COS rate structure under Schedule 96 or through a special contract for generation via long-term off-take agreements or ownership model or a combination of the two. This structure offers choice while preserving the integrity of Oregon's electric system and mitigating the risk of unwarranted cost shifts to existing customers.

For data center customers electing Schedule 96 COS without special contracts, generation costs would be allocated to the class based on the PGM. For data centers pursuing special contracts through Schedule 96, the full cost of the dedicated resource—including capacity, integration, and any system-related obligations—would be borne by the contracting data center customer. To ensure this framework functions as intended, PGE urges the Commission to include three key elements:

- Require binding financial or contractual commitments to enable accurate forecasting and timely procurement for either PPA-based or utility-owned resources.
- Mitigate risk to existing customers from stranded costs through clear cost allocation, exit fee provisions, and planning alignment.
- Support expedited generation procurement to allow customers with time-sensitive needs—such as data centers—to secure service quickly, provided they are willing to pay the full and fair cost of that service.

VII. Load Following Credit

Q. What is the rationale for the Load Following Credit for Schedule 90?

A. To receive the load-following credit a customer must meet the following conditions, the customer must have aggregate energy usage above 250 MWa and maintain a load factor of 80% or greater for each account. The benefits of volume and load factor are significant for the remainder of PGE's customer base. Due to the consistent nature of Schedule 90's load, PGE does not need to operate a peaker plant or buy energy in the short-term market to serve this customer's load. The load-following credit recognizes this benefit.

Q. What is the impact of removing the load following credit?

A. Table 8 shows the impact across customer classes if the load following credit were removed from the final compliance filing of PGE's 2025 general rate review, UE 435.

Table 8
Removal of Load Following Credit

Customer Class	UE 435 Price Change	Impact of Removing Load Following Credit
Schedule 7	5.4%	-0.2%
Schedule 32	8.2%	-0.2%
Schedule 83	8.5%	-0.2%
Schedule 85	6.8%	-0.3%
Schedule 89	4.2%	-0.3%
Schedule 90	6.0%	2.1%
Schedule 96	[embedded in 89 & 90]	-0.3%
COS/DA Total	6.3%	0%

Q. Is PGE proposing the use of the Load Following Credit for Schedule 96 Customers?

A. No, PGE is not proposing to apply the Load Following Credit to Schedule 96.

Q. Does PGE support the continued use of a load following credit?

A. PGE is not taking a position on the load following credit at this time, but we are open to reviewing and responding to other parties' positions.

VIII. Qualifications

Q. Ms. Ferchland, please state your educational background and qualifications.

A. I received a Bachelor of Science in Electrical Engineering and a Master of Business Administration both from the University of Denver and a Post-Baccalaureate in Accounting from Portland State University. I joined PGE in 2015 as an Investor Relations Analyst and transitioned to the Principal Treasury Analyst role in 2017 where I worked with PGE's revolving credit facility, debt issuances, and annual rating agency presentations. I became the Manager of Revenue Requirement within Rates and Regulatory Affairs in November 2019, and the Senior Manager of Pricing, Tariff and Power Cost Recovery in February 2025.

Q. Mr. Barrow, please state your educational background and qualifications.

A. I received a Bachelor of Arts in Business with a dual major in management and marketing from Portland State University. I joined PGE in 2018 in the Business Development department. In 2019 I transitioned to the role of Commercial Real Estate Market Manager, leading efforts to engage with builders, developers, and projects to pursue increased electrification and grid interactive program enrollment. In 2022 I became the Manager of Commercial Offerings, leading the development and evolution of programs and offerings for non-residential customers, including data centers. In April of 2025 I became the Senior Manager of Data Centers and Growth with the creation of the team.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
101	Schedule 96 Tariff
102	Marginal Cost Study Impacts
103	Letter to Governor Kotek from Chair Tawney
104	Substation Engineering Estimates
105	Rule I Redlines

SCHEDULE 96
DATA CENTER
STANDARD SERVICE
(FACILITIES >20,000 kW)

PURPOSE

This tariff describes the terms and conditions for facilities whose end use is a Data Center. Customers subject to this Schedule may be tenants of companies who build, develop and may own the Data Center or customers who are landlords with tenant companies who are data centers. Tenants of data center campuses or sites individually metered that receive service from the Company are subject to this schedule even if the site demand does not exceed 20,000 kW at the time of energization, but where the aggregated site exceeds 20,000 kW or has contracted with PGE for at least 20,000 kW.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To each Large Nonresidential Customer whose Demand has exceeded 20,000 kW or has a contract for demand of 20,000 kW or greater within their site point of delivery who is engaged directly in providing a service described under code 518210 of the 2022 North American Industry Classification System ("data center services") or who is indirectly related as a landlord with tenants engaged in providing data center services.

SCHEDULE 96 (Continued)

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Service Point (SP)*:

	Primary	Subtransmission
Basic Charge	$12,000.00	$12,000.00
Transmission and Related Services Charge		
per kW of monthly Peak Demand**	$3.11	$3.27
Distribution Charges***		
The sum of the following:		
per kW of Facility Capacity		
First 4,000 kW	$5.68	$5.68
Over 4,000 kW	$5.37	$5.37
per kW of monthly Peak Demand**	$1.61	$0.27
System Usage Charge		
per kWh	2.89 ¢	2.89 ¢
Generation Demand Charge	$18.67	$18.34
Per kW of monthly Peak Demand**		

* See Schedule 100 for applicable adjustments.
** Peak Demand hours are Monday - Saturday 6:00 a.m. to 10:00 p.m.
*** The Company may require a Customer with dedicated substation capacity and/or redundant distribution facilities to execute a written agreement specifying a higher minimum monthly Facility Capacity and monthly Demand for the applicable SP.

Energy Charge Options:

Any Energy Charge option selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option below and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service. If a Customer chooses Direct Access Service or a pricing option other than the Cost of Service Option, it may not receive service under the Cost of Service Option until the next service year and with timely notice.

NON-COST OF SERVICE OPTION

Daily Price Option - The Intercontinental Exchange Mid-Columbia Daily on- and off-peak Electricity Firm Price Index (ICE-Mid-C Firm Index) plus 0.319¢ per kWh for wheeling, plus losses. If prices are not reported for a particular day or days, the average of the immediately preceding and following reported days' on- and off-peak prices will be used to determine the price for the non-reported period. Prices reported with no transaction volume or as "survey-based" will be considered reported. To begin service under this option, the Customer receiving service under Cost of Service price option will notify the Company by the close of the November Election Window or for eligible Customers, the close of a Balance-of-Year Election Window.

SCHEDULE 96 (Continued)

NON-COST OF SERVICE OPTION (Continued)

Losses will be included by multiplying the above applicable Energy Charge Option by the following adjustment factors:

Subtransmission Delivery Voltage	1.0416
Primary Delivery Voltage	1.0530

Non-Cost of Service Option is subject to Schedule 128, Short Term Transition Adjustment

PLUG-IN ELECTRIC VEHICLE TIME OF USE (EV TOU) OPTION

Should a Customer receiving service under this Schedule 96 opt for a separately metered EV TOU option, the separately metered Electric Vehicle charging load will determine the applicable rate schedule under which EV TOU charging service is provided. For example, please refer to Schedules 32 and 38.

ELECTION WINDOWS

Balance-of-Year Election Window

The Balance-of-Year Election Window begins at 8:00 a.m. on February 15th (or the following business day if the 15th falls on a weekend or holiday). The Window will remain open from 8:00 a.m. of the first day through 5:00 p.m. of the third business day of the Election Window.

During the Balance-of-Year Election Window, a Customer may notify the Company of its choice to move to Direct Access Service. For the February 15th election, the move is effective on the following April 1st. A Customer may not choose to move from an alternative option back to Cost of service during a Balance-of-Year Election Window.

November Election Window

The November Election Window begins at 2:00 p.m. on November 15th (or the following business day if the 15th falls on a weekend or holiday). The November Election Window will remain open until 5:00 p.m. at the close of the fifth consecutive business day.

During a November Election Window, a Customer may notify the Company of its choice to change to any service options for an effective date of January 1st.

During an Election Window, Customers may notify the Company of a choice to change service options using the Company's website, https://portlandgeneral.com

SCHEDULE 96 (Concluded)

MINIMUM CHARGE

The Basic, Distribution, Transmission, and Generation Charges specified in this schedule will be subject to minimums specified in Rule I and the Customer Service Contracts required under this Schedule. The minimum Facility Capacity and Demand (in kW) will be 200 kW and 4,000 kW for primary voltage and Subtransmission voltage service respectively, unless different minimums are specified in the Customer Service Contract.

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

CONTRACTS

The following customers must enter into a contract with the Company for the provision of service: Customers commencing service after the effective date of HB 3546 (the Power Act) (June 16, 2025) or commencing service before June 16, 2025 if the provision of electricity service requires the Company to make significant investments or incur costs after June 16, 2025, that could result in increased costs or risks to other PGE retail customers. Customers required to enter into a contract for service under this Schedule may sign a contract with the Company consistent with the terms and conditions of this Schedule and Rule I or enter into a special contract with the Company for provision of electricity service, including as applicable, transmission, distribution, energy, capacity or ancillary electricity services. Any special contract signed by a customer and the Company under this Schedule shall be subject to Commission review and approval.

ADJUSTMENTS

Service under this schedule is subject to adjustments approved by the Commission. Adjustments include those summarized in Schedule 100.

TERM

Service will be for not less than one year or as otherwise provided under this schedule or the Customer Service Agreement.

Incremental impacts assuming inclusion of Schedule 96 in final UE 435 Compliance Filing

Sch	+ new Dist MC (excl. substns)	+ new substns	+ Trans PCM	+ Gen PCM	**Sum of proposed changes**
7	-0.2%	0.0%	-0.4%	0.0%	**-0.6%**
15	-0.6%	0.0%	-2.0%	-0.8%	**-3.4%**
32	-0.2%	0.0%	-1.3%	-0.7%	**-2.3%**
38	0.9%	0.8%	0.3%	0.6%	**2.6%**
47	2.3%	-0.1%	0.6%	0.4%	**3.2%**
49	0.7%	1.3%	-1.6%	-1.0%	**-0.7%**
83	-0.2%	0.7%	-1.3%	-0.7%	**-1.4%**
85	1.0%	0.7%	-0.5%	-0.6%	**0.7%**
89	-0.1%	-0.9%	-1.2%	-1.6%	**-3.7%**
90-P	0.0%	-1.0%	0.4%	-0.1%	**-0.7%**
91/95	-0.6%	0.0%	-1.9%	-0.7%	**-3.3%**
92	-0.6%	-0.1%	0.0%	-0.2%	**-0.9%**
96	0.0%	-1.0%	11.2%	7.8%	**17.9%**
COS	0.0%	0.0%	-0.2%	0.0%	**-0.2%**
DA	2.5%	-2.1%	14.5%	0.0%	**14.8%**
COS/DA	0.0%	0.0%	0.0%	0.0%	**0.0%**

Oregon
Tina Kotek, Governor

Public Utility Commission
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503-373-7394

August 1, 2025

Dear Governor Kotek:

Thank you for your letter, dated March 20, 2025, describing the challenges facing the electricity sector in Oregon and your priorities, particularly emphasizing the need to protect the most energy burdened customers, manage the rapid addition of large loads and deliver on the clean energy goals set out in HB 2021. We appreciate your recognition of the Commission's ongoing work on these critical issues, and we are pleased to respond to your request for more information.

The Oregon Public Utility Commission has served Oregonians for over 150 years, ensuring access to safe, reliable, and fairly priced utility services. This is a moment of unprecedented investment in the electricity system – investment needed to avoid other, higher costs such as wildfire damage or volatile energy market prices and to deliver on the Legislature's vision of a more equitable and cleaner system. The PUC's work lies at the intersection of competing interests, balancing inherent tensions to find solutions that allow for the necessary growth and change efficiently and avoiding unnecessary spending. We have the tools to hold utilities accountable and discipline their spending. We will also continue to provide targeted support to the most energy burdened. However, we have limited ability to avoid the impact of costs outside of even the utilities' control such as unbounded wildfire liability, necessary transmission expansion and the impact of federal policy changes on customer bills. We look forward to working with you and the Legislature on these issues.

The following is a brief summary of the challenges before us, our past actions and the steps we plan to take. Following the summary is an appendix with more detailed information.

Recent Utility Bill Cost Drivers

Frequent rate cases and other rate adjustments have led to rapidly rising customer bills, creating hardship for customers already struggling with other daily costs. While the cost drivers differ between utilities and over time, the primary factors putting upward pressure on rates include regional and global natural gas price volatility, high energy demand events driven by extreme weather, storm and wildfire recovery costs, accelerating wildfire hardening to reduce risk to communities, transmission and distribution system investments and overall inflation and supply chain constraints.

Efficiency and Forward-looking Cost Discipline

Our primary focus is, and always has been, on holding utilities accountable to deliver safe, reliable service to all customers at the lowest cost. We have proactively disciplined utility costs through planning processes, like the Integrated Resource Plans, that subject utility investment strategies to stakeholder and Commission review before money is spent. For example, recognizing that the electric distribution system required significant modernization, we instituted Distribution System Planning in 2021, to bring transparency to a substantial, ongoing area of utility investment.

To discipline power costs, which make up roughly half of customers' utility bills, we have long required the utilities to bear some risk and cost for fuel and power costs. This performance-based ratemaking is relatively unique in the country and has been held up as a positive example by research groups such as the Rocky Mountain Institute. We also subject power cost forecasts and true ups to stringent annual reviews, where parties such as the Citizen's Utility Board and Association of Western Energy Consumers can dispute utility forecasts and contracts.

In rate cases, which include thousands of data requests to examine the utilities' rate proposals in detail, a wide range of utility costs are scrutinized by PUC staff and multiple intervenors with the goal to eliminate spending on items deemed unnecessary and to minimize necessary expenses where possible. We continue to invest in our staff's capabilities to perform this scrutiny effectively, as well as investing in the capacity of the stakeholder community through our intervenor funding program.

We have also invested heavily in programs to most efficiently utilize existing resources. For example, the Energy Trust of Oregon has avoided the need to build multiple gas plants through energy conservation and distributed generation projects. Participation in the Western Energy Market has also reduced emissions and fuel use and in turn saved millions of dollars in power costs each year.

Ongoing Cost Pressure

Despite this work, utility rates have accelerated in Oregon beyond the pace of inflation and burdened customers. Addressing cost drivers requires, in many cases, investing in the systems we depend on to mitigate future rate impacts. For example, the region requires additional transmission and generation to meet load growth and decarbonization goals and protect reliability during extreme weather conditions. Postponing those investments exposes customers to very high market prices, coal and natural gas price volatility, and reliability risks. Utility wildfire liability risk is extremely high and is expanding as Oregon grapples with repeated droughts. Accelerated investments to harden the infrastructure and manage tree mortality inside and outside the utility right of way is required to avoid catastrophe.

While the Commission's existing – and new – authorities provide ample tools to discipline costs and ensure efficient solutions to many cost drivers, there are areas the Commission likely cannot materially reduce or avoid increased costs. These are:

1. Recent actions by the federal government including energy import tariffs, permitting changes on federal lands, elimination of tax credits, withdrawal from several federal spending commitments such as the Columbia Basin Restoration Initiative, the proposed elimination of energy bill assistance (LIHEAP), and the cancellation of several clean energy manufacturing facilities fundamentally increase the costs of many unavoidable investments and reduces the federal contribution to the Oregon energy system. Utility customer bills will bear the brunt of these changes.

2. Unbounded utility wildfire liability will drive up the cost of utility capital, raising the overall cost of every utility investment. It will also continue to require the prioritization of scarce capital towards extensive grid hardening, pressuring customer bills and limiting capacity for goals such as economic development and decarbonization, as we have observed in California.

3. The scale of required transmission investment is likely beyond the ability of any one entity to finance, particularly as wildfire liability risk limits Oregon IOU's access to capital at reasonable cost. Additionally, customers beyond the Oregon IOUs benefit from these investments. The State must find avenues to spread transmission costs across more beneficiaries and access other sources of capital. The lack of a large-footprint RTO to manage transmission expansion requires bespoke solutions to these issues. We are extensively participating in regionalization efforts to facilitate solutions, but those are also limited and likely insufficient to the challenge, on their own.

Protecting Vulnerable Customers

Despite our scrutiny and discipline, utility costs will continue to be pressured in coming years, so the Commission is focused on protecting the most vulnerable, energy burdened households from price shocks. We continue to advance tools to reduce bills and provide targeted support, in close consultation with impacted communities and in light of a growing body of Oregon specific data.

All of the utilities we regulate have implemented tiered rates for households experiencing low incomes. Our most recent data shows Portland General has enrolled roughly 65% of their eligible customers and Pacific Power has enrolled roughly 41%. This uptake can be compared to the more limited reach of emergency energy assistance, which typically serves only 15 to 18% of eligible customers.

We continue to revise our requirements for programs to target those most needing support and expand uptake. For example, utilities can now identify which energy burdened households have the highest usage and work directly with Energy Trust of Oregon to target more extensive energy efficiency upgrades to those addresses to reduce usage and cost over the long run.

This success, in and of itself, does become a cost for other customers, just as other policy programs like community solar and necessities like wildfire hardening do. PGE currently estimates the annual cost at $67 million and Pacific Power estimates an annual cost of $22 million for 2025.

Commitment to Oregonians

We remain committed to diligent scrutiny of utility investment plans and rate recovery requests. We will continue to improve and adapt our processes as emerging issues, such as the unexpected and sudden end of clean energy tax credits, demand. We will continue to discipline utility spending to ensure they deliver safe, reliable and clean power at the lowest cost possible.

Below is a comprehensive list of ongoing processes, legislative implementation plans and planned projects. For example, we are undertaking further revisions of the rules governing disconnection for non-payment. We are implementing risk/spend efficiency metrics to better discipline spending on wildfire hardening. We will continue to address PGE's New Large Load tariff proposal under the direction provided by HB 3546. We will also continue to accelerate ongoing utility procurement to effectively compete for projects eligible for federal tax credits.

However, the cost of all sources of energy is rising rapidly, driven in large part by federal policy changes. Significant investment is necessary to enable economic development, adaptation to new wildfire and other climate risks, and decarbonization. In light of the ongoing pressure, we will continue to listen closely to impacted customers and improve targeted support for the most vulnerable. We look forward to working with you and the Legislature to navigate Oregon through this challenging time.

Sincerely,

Letha Tawney

Letha Tawney

Chair, Oregon Public Utility Commission

Appendix: Past Decisions and Future Processes Addressing Priority Issues

This Appendix responds to the three areas of focus outlined in the March 20th letter:

1. Energy burden, implementation of docket UM 2475, and studies and actions to focus ratepayer-funded distributed energy resource programs on customers with the highest energy burden and on resources that provide measurable energy resilience benefits;

2. The impact of new large users and our efforts to understand and address the impact of these loads;

3. Commission actions to address transmission and distribution challenges and create new opportunities for cost-effective resources to meet reliability and clean energy needs.

Part 1: Affordability and Energy Rate Classification

Energy burden is the percentage of a household's income that is spent on energy costs, including electricity and heating. Commission Staff address energy burden through a hierarchy of actions. The first priority is to ensure utilities are considering their resource options in a least-cost, least-risk manner in any revenue recovery proceeding. Next, we ensure that – as outlined in your letter – existing energy programing opportunities that may save customers energy are in part directed to those with the highest energy burden. We set expectations that utility bill discount programs are available, known, and targeted to those same energy burdened customers. The Commission continues to evaluate and implement ways to prevent people from getting so far behind on bills that they cannot catch up or face large, one-time payments with programs such as arrearage management and payment plans with blended grants. Finally, we have extended disconnection/reconnection protections and reduced punitive fees for energy burdened customers.

Current Proceedings to Implement HB 2475 (2021)	
Area of Focus:	Description of Agency Actions:
Rate Design	Rate design is the process of creating customer rates to allocate the cost of providing service across different types of customers. As you noted, HB 2475 provided the Commission new authority to classify customers by their energy burden and design rates accordingly.

	By 2022, the Commission approved interim bill discount programs for all large energy utilities. (Idaho Power implemented a bill discount program in 2024.) These programs were developed to prioritize relief for those most in need, provide low barriers enrollment, bundle bill discounts with energy efficiency and other relief programs, and utilize feedback and data analysis to continually improve and right-size the programs. Between 2022 and the fall of 2024, all energy utilities performed Energy Burden Assessments to understand their customer needs in significantly more detail. In response to these assessments, the Commission has required revisions in individual utility bill discount programs, adding more tiers and deeper discounts and requiring additional outreach to ensure extensive enrollment. The Commission has addressed and will continue to address the cost allocation of these discounts as they are recovered from non-participating customers, including large customers.
Customer Disconnection Protection	During the COVID-19 pandemic, the PUC put in place temporary disconnection moratoriums across the energy utilities. In fall of 2022, before lifting the blanket disconnection moratorium, the Commission updated OAR 860-021 to significantly extend permanent protections for low-income customers, reduce fees and late charges and reduce other access barriers. In fall of 2024, in response to emerging disconnection data, the Commission adopted emergency rules further limiting severe weather disconnections, extending protections for low-income and medical certificate holders, changing deposit and late fees, and reducing reconnection fees. These protections prioritized the health of the customer when energy is vital to maintaining a safe home environment. Staff is currently workshopping permanent updates to the disconnection protection rules with stakeholders, targeting adoption by the end of 2025.
Arrearage Management	Arrearage management provides a structured payment approach to energy burdened customers who fall behind on payments and is an important tool to prevent disconnection or customer use of payday loans or other negative

	financial decisions such as skipping medication in order to avoid disconnection. In response to the extraordinary customer arrearages accumulated during the pandemic, the Commission established a blend of interim grant programs and time-delimited arrearage management programs to support energy burdened customers returning to financial stability while avoiding significant utility bad debt or customer disconnections. These programs were differentiated by utility and in place several months before the temporary disconnection moratorium was lifted. This further reduced the risk of significant disconnections. As a result, utility bill arrearages normalized to pre-pandemic levels in Oregon without a significant increase in disconnections and well before arrearages normalized in peer states such as Washington and California. In fall of 2024, the Commission required all energy utilities to re-establish arrearage management programs to address the emerging disconnection data.
Procedural Justice	1. Intervenor Funding - the Commission has implemented the environmental justice intervenor funding provisions of HB 2475. This required the negotiation of a funding agreement for justice groups, developed with utilities, and the implementation of rules. The funding opportunity has been in place since 2022 and resulted in a significant increase in the number of community focused and consumer groups participating in our proceedings. 2. Rate case enhancement – Staff has taken tangible actions in rate cases to structure the process so that smaller, community focused organizations can effectively participate in key docket events, such as settlement. This has led to settlement outcomes that address more issues and concerns central to the communities represented by these organizations. 3. Staff is currently drafting a Procedural Equity report, which will propose further enhancements to Staff led Commission processes in 2026.

Data and Metrics	1. Enhanced energy burden reporting – in 2024, informed by the completed Low-Income Needs Assessments, the PUC updated enhance energy burden data reporting requirements for electric and natural gas utilities, including service disconnections for non-payment, customer arrearages, and information to understand the relationship between income, housing type, and customer energy use patterns. 2. Community Benefits Indicators – in 2023, the Commission began requiring the use of community benefits indicators to capture the cost, benefits, and impacts of long-term resource planning decisions on environmental justice communities. We continue to work with stakeholders and utilities to enhance the value of the metrics.
Energy Efficiency Programing	Staff is working with the Energy Trust of Oregon (ETO) to increase the number of customers receiving no- or low- cost energy efficiency offers. Staff and Commissioners have consistently reinforced at annual budget meetings and in associated comments the need to increase the organization's impact and focus upon those customers experiencing energy burden and work with non-profit, community partners. This was a repeated priority in ETO's 5-year strategic plan process, which concluded at the end of 2024. The following tangible actions have been taken to address energy burdened customers with ETO: 1. ETO annual reporting to the PUC includes tracking metrics for program delivery to energy burdened customers. 2. Staff facilitated and established channels between ETO and utilities for the secure sharing of Income Qualified Bill Discounts information. With the infrastructure now in place, ETO has begun to target no-or low-cost incentives to these customers. 3. The PUC modernized the agreement with ETO, allowing ETO to explicitly consider benefits to those experiencing energy burden when developing programs.
Transportation Electrification	The PUC oversees each electric utility's transportation electrification plans and the implementation of the Legislature's direction to target 50% of the funding to underserved communities. This includes the development of community benefits indicators. For example, in Pacific Power territory, 97% of all program-enabled charging ports funded in 2024 benefited

	low-to-moderate income customers.
Community Solar Program	Oregon is a national leader in "low-income" participation in community solar programs. The OPUC has established a Low Income Facilitator to ensure thoughtful implementation of the Legislature's direction to ensure income qualified participation. As of February 2025, 11% of all installed CSP capacity serviced low-income households which totaled over 1,000 homes and 1,300 multi-family units saving on average 10.5% off their bills annually.
Storage Pilots	Staff is working with both PacifiCorp (PAC) and Portland General Electric (PGE) on storage pilots that focus on community resilience. PacifiCorp is nearing the completion of 2 MW / 6 MWh battery at a substation in Klamath Falls that was selected under the docket UM 1857 pilot program to improve system resiliency. Additionally, PAC has partnered with ten communities to scope and design on-site storage projects at community facilities designated to provide resiliency benefits. Behind-the-meter (BTM) battery storage systems have been growing at PAC under a pilot partnership with ETO. PacifiCorp now has over 10 MW of BTM storage, largely paired with solar systems. Through work with OPUC staff, PAC is updating its Wattsmart program to dispatch these batteries during grid events. PGE has one storage pilot designed to improve resiliency with 4.2 MWh of BTM storage.

Future Proceedings to Implement HB 2475 (2021)	
Area of Focus:	Description of Agency Actions:
Rate Design Investigation (2026)	Using the results of Staff's current Energy Burden Rate Design research project, completing in 2025, Staff and stakeholders will evaluate additional implementation options to mitigate energy burden, promote energy efficiency, and ensure cost-based rates.
Legislative Implementation	Two significant pieces of rate-related legislation passed in the 2025 session; SB 688 – a performance ratemaking bill that give the Commission new resources and direction to use rate-focused incentives to change utility priorities, performance, and operations – and HB 3179 – a significant bill that will move Oregon to multi-year rate planning. We will look for opportunities to leverage new tools for cost discipline as we implement this 2025 legislation, and we are currently developing a comprehensive implementation plan.

Part 2: Large Loads

The Commission recognizes the significant impact new large loads can have on Oregon, region, and on other customers. In multiple investigations – described below – our focus has been geared toward protecting consumers, ensuring appropriate cost allocation, and protecting reliability. That noted, large loads also present opportunity – and we are currently reviewing and considering how we can use the capabilities, capital/resources, and load profile of new large loads to meet system needs and support existing clean energy and other policies. Importantly, new legislation passed in the 2025 session gives the Commission tools to ensure new large loads do not create impacts on other customers and can allow Oregon to potentially leverage these loads to achieve state goals. Finally, we note that effective approaches to large load issues will require collaboration with other agencies, particularly Oregon Department of Energy.

Past Proceedings on Large Load Growth Management	
Docket:	Description of Agency Actions:
UE 358 PGE's New Load Direct Access (2020)	New large load is generally not planned for in standard utility procurements. This docket implemented a customer choice program that leverages that fact to allow these customers to select an energy supplier other than their incumbent utility in a way that mitigates risk to all customers, promotes competition, and can further accelerate emissions reductions.
UM 1953 Voluntary Renewable Energy Tariff (VRET) (2019-2024)	This docket implemented a program to allow large customers further flexibility in their generation mix, allowing them to procure or subscribe to emissions free generation without leaving the utility's service or impacting the costs or risks of all other customers. Some of Oregon's largest employers utilized this program to achieve their own emissions goals, accelerating the decline of carbon emissions and supporting compliance with HB 2021.
UE 433 – PacifiCorp General Rate Case (GRC) (2024)	This 2024 rate case implemented extensive protections for smaller customers from the risks of large loads coming on to the system. The Commission adopted policies that work to align incentives of large and small customers, protecting against stranded asset and class cross-subsidization risks.

UE 430 – PGE Large Load (2023-2025)	This docket was an investigation into the costs and risks posed by large datacenters on PGE's system, in response to PGE's proposed tariff approach. Issues identified in this docket are now being addressed and resolved in docket UM 2377, discussed below.

Current Proceedings on Large Load Growth Management	
Docket	Description of Agency Actions:
UM 2377 – Follow-up Large Load Docket (Active)	Staff and stakeholders are working to mitigate the costs, risks, and impacts of large load connections on PGE's system while implementing policies that leverage the sophistication of the customers to maximize benefits to the system. The docket has a holistic scope, identifying the appropriate contract terms, cost allocations, and compliance implications.

Planned Proceedings on Large Load Growth Management	
Area of Focus:	Description of Agency Actions:
HB 3546 Implementation	HB 3546 directs the PUC to create a separate rate class for data centers. The new rate class must be separate and distinct from classifications of service for other commercial or industrial retail electricity consumers and have its own tariff schedule. The bill outlines specific requirements for the tariff schedule, including that it must directly assign costs of serving large energy use facilities to those consumers and mitigate risks of cost shifting to other rate classes. HB 3546 also directs the PUC to require electric utilities serving large energy use facilities to enter into a contract with the consumer and spells out certain requirements for these contracts, including that they be for a duration of 10 years or longer. These requirements apply to contracts entered into on or after the effective date of the bill. HB 3546 implementation will build on the progress we have made to date on this issue. The PUC intends to act on its direction through tariff filings beginning with completion of docket UM 2377 for PGE. Staff will review existing requirements in PacifiCorp territory for consistency with HB 3546 and update as needed in future dockets. Recognizing the new precedent of defining a rate class based on industrial sector, HB 3546 directs the PUC to review trends in data center and other

	large retail electricity consumer load requirements and report biannually on these trends to the legislature. Staff will coordinate with ODOE regularly to share information on broader trends in large users and incorporate relevant information in these reports. Ultimately, the goal for this implementation effort is to ensure that new data center load growth in IOU territory does not put unwarranted costs on other ratepayers – beyond this, we hope to leverage new large load growth to support broader state goals and responsibilities for the Commission.

Part 3: Transmission and Distribution; New Resources

Oregon faces a confluence of issues in our near and long-term efforts to decarbonize our energy system. Like many states, we face increasing load growth – not just from data centers – as discussed above, but also from sustained transportation electrification and other forms of electrification and manufacturing expansion. At the same time, Oregon faces significant transmission barriers – with geography, development timelines, ownership structures and costs all presenting challenges to the deployment of new resources. To address this, we have been focused on the following: modernizing procurement to take advantage of previously overlooked transmission products, increasing non-wires solutions to reduce energy and capacity needs, and looking to the future – to continue to support regional transmission efforts and to implement new legislation affecting resilience. Below is a brief description of measures the Commission has taken to prioritize actions that make progress on emission while targeting reliability, resilience, community benefits, and affordability.

Current Proceedings on Transmission and Distribution	
<u>Area of Focus:</u>	<u>Description of Agency Actions:</u>
Integrated Resource Plans and Distribution System Plans	The Commission has been modernizing resource and infrastructure planning requirements to focus on the most important challenges to maintaining a reliable and affordable energy system during the clean energy transition. The Integrated Resource Plan (IRP) process actively evaluates transmission, including upgrades to existing lines and the application of new technologies, as a resource to access lower-cost, non-emitting resources regionally and across the West. The Distribution System Planning (DSP) process explores programs and local investments that enable cost-effective alternatives to larger transmission investments. Information and stakeholder input from both planning processes are leveraged by and inform the other. This enables a holistic transmission and distribution planning environment that guides system investments, which make up the majority of

	utility capital investment, while reflecting the multitude of policy goals and stakeholder perspectives needed to enable the infrastructure undergirding Oregon's energy transition.
Demand Response Programs	Over the past five years, we have required both PacifiCorp and PGE to develop a suite of reliable and cost-effective Demand Response (DR) programs for all classes of customers. These programs send signals to customers to cost-reduce energy need during critical peak hours in the winter and summer. In 2024, PGE was able to reduce peak summer demand on the hottest day of the month by nearly 4%, greatly reducing stress on the transmission and distribution system. DR programs provide cost-effective solutions to utilities to avoid purchasing high-cost, peak energy while reducing the strain on and need for new transmission and distribution infrastructure. These programs also enable customers to directly control their energy expenditures.
Request For Proposal (RFP) Modernization	Staff, utilities, and stakeholders have sought to optimize the use of existing transmission assets by renewable resources in RFPs to avoid unnecessary spending. By adjusting compensation frameworks, sharing transmission asset availability, and rightsizing capacity expectations for intermittent resources, both PAC and PGE have allowed for greater project participation in RFPs while minimizing the need for new transmission infrastructure. These changes reflect direction from the IRP/RFP modernization process, which sought to make RFPs more competitive, streamlined and transparent.
CPCN Rules Modernization	In 2022, we completed a modernization of the rules governing the evaluation of utility requests for a Certificate of Public Convenience and Necessity for a transmission project. We particularly expanded the requirement to demonstrate that non-wires alternatives such as Grid Enhancing Technologies and targeted energy efficiency and demand response were fully evaluated as alternatives to a new transmission project.

Future Proceedings on Transmission and Distribution	
<u>Area of Focus:</u>	<u>Description of Agency Actions:</u>
New Legislative Direction	The PUC received new direction on both distributed resources and transmission through bills on microgrids (HB 2065 and HB 2066) and grid-enhancing technologies (GETs). Both of these technologies offer paths to maximize the capacity of existing grid and transmission systems while long-term and regional processes to plan new transmission are underway. 1. Microgrids are an emerging technology which allow a section of the grid to separate from the rest of the grid and remain energized if the rest of the utility grid is down. This allows local communities to keep the power on when outages occur, particularly for critical infrastructure. In some cases, microgrids can also help the grid if they can deliver energy back to the system at key summer and winter peak hours or help solve grid engineering issues like power quality stabilization. 2. The PUC will develop a regulatory framework for microgrids that will provide needed clarity on numerous aspects of microgrid ownership, deployment, and operation. This clarity, especially if complemented by new resources to fund community projects and technical assistance, will provide a smoother path to microgrid projects that bolster both local and broader grid resilience. 3. Grid-enhancing technologies (GETs) are a suite of technologies that can increase the efficiency of the transmission system and more actively manage the flow of electricity in power lines. For example, PacificCorp is currently implementing dynamic line ratings throughout their six-state footprint. HB 3336 requires utilities to analyze cost-effective ways to use these technologies and file regular strategic plans for GETs deployment. The PUC will provide guidance on evaluating GETs cost-effectiveness to help prioritize projects that bring the most value to customers.

UM 2377

Exhibit 104 has been retained in its native format

RULE I
NEW CONNECTIONS, LINE EXTENSIONS, AND SYSTEM UPGRADES

1. Purpose

This rule establishes procedures and defines respective cost responsibilities for new Electricity Service connections or increases to existing Electricity Service and their respective system upgrades including but not limited to a Line Extension to a builder, developer, Customer or Applicant who requests a Line Extension on its own behalf, or a Customer or Applicant's agent.

A. Generally

Line Extensions will be at primary and/or secondary voltage levels. Modifications to transmission or subtransmission voltage facilities or substations are not considered Line Extensions for purposes of this rule and require special contract arrangements. When an agent requests a Line Extension on behalf of a Customer or Applicant, the agent must provide documentation acceptable to the Company evidencing its authority to request a Line Extension.

B. Definitions

1) **Allocated System Capacity**
The capacity on the Company's transmission system that is available to reliably serve an Applicant or Customer and that the Company allocates as a result of the system capacity allocation process, which is reflected in the Customer Service Contract.

2) **Applicant**
For purposes of this rule, an Applicant is a builder, developer, Customer, Applicant or other Customer or Applicant agent requesting a Line Extension to:
a) Serve new construction; or
b) Obtain additional capacity for, or a change in, service conditions relative to existing Distribution Facilities.

3) **CIAC**
An elective contribution in aid of construction of 50% of the Estimated Cost of the Work paid by Customer to the Company pursuant to the terms of the Customer Service Contract.

4) **CIAC Billed Demand Credit**
A credit to the billed demand charge (as a kW or MW equivalent) calculated as a proportional credit to the annual revenue requirement based on the Customer's CIAC.

RULE I (Continued)

Definitions (Continued)

~~3)~~5) **Cost of Work**
The Company's actual direct and indirect costs to install new, additional, or upgraded Distribution Facilities to serve the Applicant's planned Electricity needs and assigned to the Applicant in the Customer Service Contract, including but not limited to administrative and engineering design costs.

6) **Customer Service Contracts**
~~4)~~ ~~a~~Are either (1) a Minimum Load Agreement (MLA) for Applicants in Capacity Category 2B or (2) a Large Load Customer Agreement (LLCA) for Applicants in Capacity Category 3, the terms and conditions for which are outlined in this Rule I.

~~5)~~7) **Distribution Capacity**
The capacity that the Company makes available to the Customer or Applicant via upgrades to existing or construction of new Distribution Facilities.
Distribution Facilities
Distribution Facilities are all structures and devices needed to distribute Electricity at any of the primary or secondary voltages listed in Rule C. Distribution Facilities will be installed in accordance with applicable laws, codes and Company standards and practices. It is the Applicant's responsibility to provide the Company with accurate information about their usage including but not limited to nameplate ratings of major installed electrical equipment and the intent to operate equipment above or below the nameplate rating. If damage results to Facilities owned by the Company through failure of the Applicant to fully disclose its load requirement to the Company, the repair and, or replacement costs of such Facilities will be paid by the Applicant.

~~6)~~8) **Enhanced Planning Area**
An area within the Company's service territory in which the transmission system requires more complex planning efforts in order to reliably serve expected capacity requirements. These designations are reviewed annually during system-wide analysis and with every study performed for customer requests. The Company will update designations based on a variety of factors such as changes in system conditions, regional growth, and/or individual capacity requests.

9) **Estimated Cost of Work**
The Company's estimated direct and indirect costs to install new, additional, or upgraded Distribution Facilities to serve the Applicant's planned Electricity needs, including but not limited to administrative and engineering design costs, as determined in the final study report issued by the Company.

RULE I (Continued)

Definitions (Continued)

~~7)~~10) **Exclusive Use Facilities**
Facilities owned and operated by the Company required to provide Electric Service to the Customer between existing Company transmission or Distribution Facilities and the Applicant's or Customer's Service Point (SP) that are for the sole benefit and use of the Customer receiving Electricity Service are Exclusive Use Facilities. Customers with Exclusive Use Facilities are responsible for all costs associated with such facilities less any Line Extension Allowance for which the Customer qualifies. Neither upgrades to the Company's transmission nor distribution network(s) made for the benefit of all respective users are considered Exclusive Use Facilities and, as such, their costs are not allocated directly to any Customer(s).

~~8)~~11) **Exit Fee**
The amount that a Customer must pay to the Company if the Customer Service Contract expires or is terminated by the Customer or by the Company in the event of a Customer default or breach or by either the Company or Customer in the event of change of law defined in the Customer Service Contract.

~~9)~~12) **Facilities Study**
A study performed by the Company that includes analysis of facilities impacts and Applicant or Customer cost allocation as applicable to Distribution Facilities upgrades or new construction required to accommodate a capacity request.

~~10)~~13) **Feasibility Study**
A high-level planning study performed by the Company to determine whether service can be provided at the location and under the timeline specified in the Applicant's request and whether new or upgrades to transmission or Distribution Facilities may be required. The results of a Feasibility Study may indicate the need for more detailed review in either a System Impact or Facilities Study.

~~11)~~14) **Line Extension**
A Line Extension is the installation of new, additional or upgraded Distribution Facilities from a point on the Company's existing distribution system that the Company provides for the Applicant's planned Electricity needs to the Applicant's Service Point (SP). Where the Applicant is requesting either a new individual residential service or an upgrade to an individual residential service, upgrades to existing primary lines will not be considered part of the Line Extension. Any new primary or secondary Line Extensions, transformer additions or replacements necessary to serve the new load will be considered part of the Line Extension. However, for residential Electric Vehicle charging-related line extensions, transformer additions or replacements necessary to serve that charging load will not be considered part of the Line Extension.

RULE I (Continued)

Definitions (Continued)

~~12)~~15) **Line Extension**
A Line Extension is the installation of new, additional or upgraded Distribution Facilities from a point on the Company's existing distribution system that the Company provides for the Applicant's planned Electricity needs to the Applicant's Service Point (SP). Where the Applicant is requesting either a new individual residential service or an upgrade to an individual residential service, upgrades to existing primary lines will not be considered part of the Line Extension. Any new primary or secondary Line Extensions, transformer additions or replacements necessary to serve the new load will be considered part of the Line Extension. However, for residential Electric Vehicle charging-related line extensions, transformer additions or replacements necessary to serve that charging load will not be considered part of the Line Extension.

~~13)~~16) **Line Extension Allowance**
The Line Extension Allowance is the portion of the Line Extension Cost that the Company will provide without charge to the Applicant. Estimated annual kWh values used to calculate non-Residential Customer line extension allowances do not reflect onsite generation.

~~14)~~17) **Line Extension Cost**
The Company's total estimated cost to install new, additional, or upgraded Distribution Facilities to serve the Applicant's planned Electricity needs. Line Extension Costs are intended to recover the expenses of labor, material and equipment involved in the design, installation and inspection of the Line Extension under the Company's design standards and using standard construction methods inclusive of but not limited to primary and secondary voltage conductors, tree trimming or tree removal, Company indirect charges and the cost of any necessary rearrangement of existing Facilities. Where the Applicant is requesting either a new individual residential service or an upgrade to an individual residential service and the transformer requires upgrading, the Line Extension Cost will be credited for the estimated original cost, less depreciation, less removal costs, of the existing transformer.
However, for residential Electric Vehicle charging line extensions, any transformer additions, or replacements necessary to serve the charging load will not be considered part of the Line Extension. Estimates of Line Extension Costs provided to Applicants are valid for six months from the date of issue. After six months the Company reserves the right to provide a revised estimate. The Line Extension Cost does not include payments to a third party for easements, additional costs associated with Underground Line Extension or other additional costs described in this rule.

~~15)~~18) **Long Side Service Connection**
A service connection, which runs parallel to the street, rather than perpendicular to the street.

RULE I (Continued)

Definitions (Continued)

~~16)~~19) **Primary Voltage Project**
A Primary Voltage Project is a planned undertaking of construction, where the Company initially installs only primary voltage facilities. Primary Voltage Projects include large lot residential subdivisions, industrial parks and other similar complexes. It is expected that within the project each Customer will be served from one or more transformers dedicated to that Customer's use.

~~17)~~20) **Public Thoroughfare**
A Public Thoroughfare is a municipal, county, state, federal, or other street, road, or highway, which is dedicated, maintained and open to public use in which the Company has the right to construct, operate, and maintain Facilities.

~~18)~~21) **Residential Subdivision**
A Residential Subdivision is a parcel of land divided into four or more smaller lots for the purpose of development or sale, which has been platted and filed under Oregon law as a subdivision. It is expected that within the subdivision several homes will be or are served from the same transformer.

~~19)~~22) **System Impact Study**
A study performed by the Company to identify system-specific upgrades or new construction required to accommodate a capacity request while maintaining system reliability, stability, and performance. The System Impact Study report also includes a rough order of magnitude (ROM) cost estimate and preliminary schedule to energization. The results of a System Impact Study may indicate the need for more detailed review in a Facilities Study.

C. **Company Requirements**

1) **Capacity Categories**
Total requested capacity by Site, as defined in Rule B and subject to the Like Ownership provision of Rule E, is categorized in this Rule as follows:

Category 1: Less than 1,000 kW
Category 2: 1,000 kW to 2~~30,000~~ 19,999 kW with

A: no required substation transformer upgrades and for which total Line Extension Costs required to serve the load request are estimated to be less than $1 million, or
B: required substation transformer upgrades or for which total Line Extension Costs required to serve the load request are estimated to be $1 million or greater.

Category 3: ~~Greater than 30,000 kW~~20,000 kW and greater

RULE I (Continued)

Company Requirements (Continued)

For customers in Capacity Categories 2 and 3, the Company will aggregate capacity requests as one Site request where buildings with Like Ownership are located within 2,500 feet or are located at greater than 2,500 feet and are electrically connected, such as served from the same substation.

Transportation electrification customers who qualify for service under Schedule 38 are exempt from requirements applicable to Capacity Category 2B or 3 under this Rule I.

2) **Facilities Equipment Sizing and Use**
It is the Applicant's or Customer's responsibility to provide the Company with accurate information about their usage including but not limited to nameplate ratings of major installed electrical equipment and the intent to operate equipment above or below the nameplate rating. If damage results to Facilities owned by the Company through failure of the Applicant or Customer to fully disclose its load requirement to the Company, the repair and/or replacement costs of such Facilities will be paid by the Applicant or Customer.

3) **Company to Determine Route**
The Company will determine the route for all Line Extensions along Public Thoroughfares and may determine the route of a Line Extension made on private property. If the Applicant requests a route different than that determined by the Company, the Company may provide the Line Extension along the requested route if the Applicant pays the Company all additional costs resulting from the provision of that route and the requested route is not contrary to Company standards and practices.

4) **Company Ownership**
The Company will own and maintain all Facilities to the SP.

5) **Company Installation**
The Company will install all Facilities to the SP except that an Applicant for overhead Facilities may arrange to have the Facilities located on the property constructed by an electrical contractor acceptable to the Company, subject to the following conditions:
   a) The Company will furnish the design and construction specifications for the connection and perform the necessary surveying;
   b) The Applicant will, prior to the beginning of construction, cause the contractor to furnish the Company a certificate naming the Company as an additional insured in an amount not less than $1 million under the contractor's general liability policy;

RULE I (Continued)

Company Installation (Continued)

c) During and after completion of the work by the contractor, the Company will make inspections. If the construction meets the Company's design specifications, the Company will accept ownership, and the Applicant will provide to the Company the title to the construction using form documents provided by the Company, together with all rights-of-way and easements required by the Company, free and clear of any liens or encumbrances; and

d) Following receipt of the title and Company-approved form documents indicating successful transfer, the Company will energize the Line Extension to make Electricity Service available to the Applicant.

e) If the Company determines that the overhead Distribution Facilities are deficient in materials or workmanship within 24 months of the time the Company energized the Line Extension, the Applicant must pay the cost to correct the deficiency to the Company's satisfaction.

6) **Unusual Distribution Facilities or Nonstandard Construction**

The Company is required to install only those Facilities deemed necessary to render service in accordance with the Tariff. The Company is not required to make Line Extensions which involve additional or unusual Facilities, nonstandard construction, or other unusual conditions. Any facilities installed at Applicant's request which are in addition to, or in substitution of, the standard Distribution Facilities which the Company would normally install but which are otherwise acceptable to the Company, the additional cost of such nonstandard Facilities will be paid by the Applicant and will not be subject to the Line Extension Allowance in Schedule 300. In the case of conversion from overhead service to underground service, Section 6 of this Rule applies. In the case of relocation or removal of services and facilities, Section 7 of Rule C applies.

2. Applicant Cost Responsibilities

A. **Payment**

Applicants who have cost responsibilities under this section and Section 3 will make payment in full at the time the Company agrees to make the Line Extension or for Applicants in Capacity Categories 2B or 3, pursuant to the terms of their Customer Service Contract.

A letter of credit or a deposit may be required by the Company if the Applicant does not meet the Company's credit requirements and is requesting capacity of 1,000 kW or greater. Applicant's payment requirements for jobs with Line Extension Costs estimated to be equal to or exceeding $250,000 but with requested capacity in Capacity Categories 1 and 2A are as follows:

RULE I (Continued)

Payment (Continued)

1) The Applicant will provide a cash payment of 10% of the estimated Line Extension Cost prior to the Company initiating design work;
2) At the time the Company orders any special order and/or long lead-time electrical and/or pathway material, the Applicant will provide a cash payment to the Company for the full cost of the order; and
3) At the commencement of construction, the Applicant will provide a payment equal to any remaining Line Extension Costs necessary to complete construction. Acceptable means of payment will be at the sole discretion of the Company.

A Line Extension Allowance shall only be available for Customers or Applicants in Capacity Categories 1 or 2A. The Line Extension Allowance will be refunded at the time the Applicant's Electricity Service is established. If Applicant's Electricity Service is not established, payments made under Section (2)(A) are not refundable.

B. **Applicants for New Permanent Service – Capacity Categories 1 and 2A**

Applicants for new permanent service in Capacity Categories Category 2A will be required to pay a nonrefundable application fee that cannot be applied to Line Extension Costs and to enter into an agreement to pay study costs and will make payment for each applicable study prior to the Company initiating the study and within specified periods to retain queue position as described in Section 4 of this rule. Applicants with requests between 1MW and 3.99MW will pay a flat rate for each study. ~~The Applicant~~Applicants with requests 4MW and greater will pay for each study based on the Company's estimated cost to complete the study, and the Applicant will be assessed or refunded the difference as applicable at the conclusion of or upon Applicant's exit from the study process.

The following provisions will apply to Applicants and Customers in Capacity Categories 1 or 2A.

1) **Individual Applicants**
Applicants for new permanent service will be responsible for the Line Extension Costs, less the applicable Line Extension Allowance listed in Schedule 300. In addition, any payments to a third party for easements, permits, additional costs associated with Underground Line Extensions, and all other additional costs described in this rule will be the responsibility of the Applicant and are not eligible for the Line Extension Allowance.

RULE I (Continued)

Individual Applicants (Continued)

2) **Other than Individual Applicants**
The Company will install a main-line primary distribution system to provide service to a project (e.g., a subdivision, industrial park, or similar project) to serve Customers within the project provided the Applicant pays in advance for: 1) the total estimated cost of the installation of a continuous conduit system which includes, but is not limited to, the costs of trenching, boring, excavating, backfilling, ducts, raceways, road crossings, paving, vaults, transformer pads and any required permits; and 2) all other Applicant cost responsibilities based on the expected load within the project. The expected load in a large lot subdivision, industrial park, or similar project is comprised of only those loads projected to be connected within the first five years. Any Line Extension refund owed to the Customer or Applicant will be based on load connected within the first five years.

In residential subdivisions or phases of residential subdivisions where Line Extensions will not require subsequent additional extensions of primary voltage Distribution Facilities to serve the ultimate users within the subdivision, the refund will be based on the Line Extension Allowances for the subdivision calculated in accordance with Schedule 300.

C. **Existing Customers – Capacity Categories 1 and 2A**

Existing customer expansions in Capacity Category 2A will be required to enter into an agreement to pay study costs and will make payment for each applicable study prior to the Company initiating the study and within specified periods to retain queue position as described in Section 4 of this rule. Applicants with requests between 1MW and 3.99MW will pay a flat rate for each study. Applicants with request 4MW and greater will pay for each study based on the Company's estimated cost to complete the study, and the Applicant will be assessed or refunded the difference as applicable at the conclusion of or upon Applicant's exit from the study process. ~~The Applicant will pay for each study based on the Company's estimated cost to complete the study, and the Applicant will be assessed or refunded the difference as applicable at the conclusion of or upon Applicant's exit from the study process.~~

The following provisions will apply to Applicants and Customers in Capacity Categories 1 or 2A.

1) **Nonresidential**
Where an Applicant is an existing Nonresidential Customer requesting an additional SP, the conversion of a single-phase service to three-phase service, or additional capacity, the Applicant will make payment in full at the time the Company agrees to make the Line Extension. The Line Extension Allowance in these cases will be based on the incremental, annual kWh to be served by the Company or, in the case of a change in the applicable rate schedule, equal to four times the increase in annual revenues from Basic and Distribution Charges.

RULE I (Continued)

Existing Customers – Capacity Categories 1 and 2A (Continued)

2) **Residential**
Where an Applicant is a Residential Customer requesting additional capacity at the same SP, the Line Extension Allowance is as listed in Schedule 300. Any excess amount will be the responsibility of the Applicant. In addition, any payments to a third party for easements, permits and additional costs associated with Underground Line Extensions and all additional costs described in this rule will be the responsibility of the Applicant and are not eligible for the Line Extension Allowance.

D. **New and Existing Customers - Capacity Categories 2B and 3**

1) Applicants for new permanent service or existing customer expansions between 1MW and 3.99MW are required to pay a nonrefundable study fee. Applicants will may payment prior to each applicable study prior to the Company initiating the study and within specified periods to retain queue position as described in Section 4 below.

~~1)~~2) Applicants for new permanent service or existing customer expansions 4MW and greater ~~in Capacity Categories 2B or 3~~ are required to pay a nonrefundable application fee and to enter into an agreement to pay study costs. Applicants will make payment for each applicable study prior to the Company initiating the study and within specified periods to retain queue position as described in Section 4 below. The Applicant will pay for each study based on the Company's estimated cost to complete the study, and the Applicant will be assessed or refunded the difference as applicable at the conclusion of each required study.

~~2)~~3) Applicants for new permanent service or existing customer expansions in Capacity Categories 2B or 3 shall be required to enter into a Customer Service Contract that will allocate the Cost of Work to the Applicant and contain other commercially reasonable terms and conditions, including but not limited the obligations and benefits outlined in this Rule I.

~~3)~~4) The Company reserves the right to recover transmission costs from Customers in Capacity Categories 2B or 3 in a manner other than through a Customer Service Contract if the nature of the transmission investments required to serve the Customer are such that an alternative method of recovery is required to avoid an inequitable or unreasonable result.

RULE I (Continued)

3. Special Conditions for Underground Line Extensions

A. **Applicability**

Underground Line Extensions will be made:

1) When required by a governmental authority having jurisdiction;
2) When required by the Company for reasons of safety, resiliency or because the extension is from an existing underground system; or
3) When otherwise mutually agreed upon by the Company and the Applicant.

B. **Responsibility for Costs**

1) The Applicant will be responsible for the current and reasonable future costs associated with the installation of the Line Extension's continuous conduit system, which includes but is not limited to, the costs of trenching, boring, excavating, backfilling, ducts, raceways, road crossings, paving, vaults, transformer pads and any required permits. The Company will own and maintain the conduit system once Company conductors have been installed.
2) At its option, the Company may perform the Applicant's responsibilities listed in (B)(1) above at the Applicant's expense or permit the Applicant to perform these responsibilities at Applicant's expense. Where work is to be performed in an existing right-of-way and requires the Company to obtain a permit from a governmental body, the Company may specify additional requirements and place restrictions on the selection of contractors.
3) Where the Company provides trenching, and backfilling, estimated actual costs will apply as specified in Schedule 300. The Applicant will be responsible for all additional costs of excavating rock, furnishing and installing raceway, excavating to a depth in excess of Company standards, manual digging, and the repair of paved roads, walks, and driveways when such work must be performed.

C. **Additional Services**

1) **Service Locates**
The Company will locate underground water, sewer and water runoff services along the Applicant's proposed trench route on the Applicant's property if requested by the Applicant.

RULE I (Continued)

Additional Services (Continued)

2) **Service Guarantee/Wasted Trip Charge**
The Company will begin the installation of residential single family underground service laterals within seven working days following the date an Applicant requests such service, except during periods of major storms or other such conditions beyond the Company's control. If the Company does not meet this standard, the Company will pay the Applicant the Service Guarantee Charge in Schedule 300. If, however, Company resources are dispatched to install the residential single family service lateral within the seven-day period and the Applicant's site or other facilities are not ready for service, the Applicant will be assessed the Wasted Trip Charge in Schedule 300.

3) **Joint Trench Installation Charge**
Upon mutual agreement between the Company and the Applicant, the Company may install telephone and cable services during the installation of the underground service lateral. The parties involved will mutually agree to the price for such service.

4. System Capacity Allocation Process – Capacity Categories 2A, 2B, and 3

Applicants in Capacity Categories 2A, 2B, and 3 will be required to enter a system capacity allocation process for system planning, energization schedule, and determination of Allocated System Capacity.

Existing customers that have already been allocated system capacity over 30 MW prior to December 19, 2023, and have entered into a service agreement with the Company but have not been energized by December 20, 2024, must agree to amend the terms of their service agreement with the Company to specify their Allocated system Capacity and associated Capacity Exceedance Threshold. These customers are otherwise exempt from this allocation process until or unless they request additional system capacity.

A. **General Conditions**

1) The Company will determine which study or studies will be required. Applicants may be required to sign a comprehensive study agreement for all required studies or individual agreements for each required study at the Company's discretion.

RULE I (Continued)

General Conditions (Continued)

2) Applicants will be placed in a queue. The Company reserves discretion to divide Applicants or Customers into separate queues and to perform studies in clusters by service interconnection, requested capacity, location within Enhanced Planning Areas, or other relevant factors. Applicants in Capacity Categories 2A or 2B in an area that has not been identified as an Enhanced Planning Area and all Applicants in Capacity Category 2A or 2B with requested capacity of less than 4 MW will be studied and positioned in the queue based upon the date of a complete Application. The Company will make a good faith effort to manage queue position on a first-come, first-served basis for such Applicants. All other Applicants in Capacity Categories 2A, 2B or 3 will be placed in a cluster study upon completion of an Application to be studied with other Applicants in the cluster study.
3) For Applicants in a cluster study, the determination of Allocated System Capacity will be assessed on a pro-rata framework based on the total requested capacity and available capacity up to the transmission system capacity limit derived based on reliability standards requirements for the transmission system. Additional system capacity may be allocated to Applicants committing to providing dispatchable flexible load pursuant to a Company-authorized flexible load program such as Schedule 200 or demand side management program.
4) Study durations may be significantly affected if coordination with other utilities is required.
5) Completion of a study by the Company does not guarantee capacity or service or that capacity will be allocated to the Applicant.
6) Failure of the Applicant to sign a required study agreement within ~~30~~ 60 days of receipt from the Company and provide any required accompanying evidence, such as property ownership or good faith efforts to acquire property, shall automatically forfeit position within the queue.
7) Generally, the Allocated System Capacity and in-service timeframe offered to the Applicant by the Company will be determined by available system capacity and the amount of capacity the Applicant requests and are subject to change by the Company until a Customer Service Contract is executed by the Applicant and the Company.

B. **Allocation Process**

1) **Pre-Feasibility Review**
The Applicant or Customer shall submit a capacity request to the Company. The request will be evaluated for pre-feasibility, which includes a high-level screening of the Company's general ability to serve the request at the specified location and within the requested timeframe.
2) **Application Submission**
The Applicant or Customer shall submit a completed application to the Company to enter into the system capacity allocation process. The Applicant ~~will~~ may be required to pay the application fee and sign the Study Agreement.

RULE I (Continued)

Allocation Process (Continued)

3) **Load Flexibility**
Applicants in a study may gain access to additional Allocated System Capacity beyond their initial allocation by participating in eligible Company flexible load programs. In order to be considered for such allocation of additional transmission capacity, an Applicant must include proposed eligible flexible load in their Application prior to the initial study. Any proposed eligible flexible load will be required to meet the applicable requirements of a Company-approved flexible load program, including but not limited to Schedule 200 and demand side management programs. Requests to add flexible load after the initial study completion may require submission of a new Application or result in the need to restudy the Application.

4) **Feasibility Study**
The Company requires a minimum of 30 days to complete Applicant's Feasibility Study and will provide the Applicant with an estimated completion date in the study agreement.

5) **System Impact Study**
The Company requires a minimum of 60 days to complete Applicant's System Impact Study and will provide the Applicant with an estimated completion date in the study agreement.

6) **Facilities Study**
The Company requires a minimum of 90 days to complete Applicant's Facilities Study and will provide the Applicant with an estimated completion date in the study agreement.

5. **<u>Customer Service Contracts – Capacity Categories 2B and 3</u>**

Applicants in Capacity Categories 2B and 3 will be required to sign a Customer Service Contract as a condition of receiving Electricity Service from the Company. The Applicant's Customer Service Contract will be provided along with the last study report of the system capacity allocation process and must be signed by the Applicant within 60 days of issuance. Failure to return a signed Customer Service Contract to the Company within 60 days of issuance will result in forfeiture of the Applicant's queue position. This requirement may be temporarily waived by PGE for a reasonable period of time if the Customer Service Contract is subject to revision based on a pending proceeding before the Oregon Public Utility Commission.

Customer Service Contracts will be form contracts with terms and conditions required by this Rule as well as other commercially reasonable terms and conditions and may be revised by the Company consistent with applicable requirements in the Company's tariffs, the Public Utility Commission rules and orders.

RULE I (Continued)

Customer Service Contracts – Capacity Categories 2B and 3 (Continued)

A. **Billed Distribution Demand**
If providing service to the Applicant requires the construction of Distribution Facilities, the Customer Service Contract will contain an annual Billed Demand that the Customer must pay at the then-current tariff rates for distribution. Billed Demand will be based on the Company's levelized annual revenue requirement associated with the Cost of Work attributable to the Customer. The annual revenue requirement for Exclusive Use Facilities is allocated 100% to the attributable Customer but is otherwise proportionally assigned. Generally, under any LLCA, the Billed Demand shall be a flat amount that the Customer will be billed at the then-current tariff rate regardless of the Customer's actual demand.

Billed Demand for a LLCA will be directly calculated as a kW or MW equivalent based on the annual revenue requirement associated with the Cost of Work. Under the LLCA, the Billed Demand will continue during any renewal period if and only if Billed Demand exceeds Allocated System Capacity. If a Customer under a LLCA would be required to pay a Billed Demand amount of less than 25% of its Allocated System Capacity, then the Customer will be billed at the greater of Billed Demand or actual demand.

Customer may elect to contribute fifty percent (50%) of the Cost of Work via a Contribution in aid of construction (CIAC) payment. Should a Customer elect to provide a CIAC, upon energization, they will be issued a fixed monthly bill credit equivalent to the kW associated with the revenue requirement of the contribution multiplied by the distribution charges at the time of the calculation. This may apply to Customers with an MLA or LLCA.

Billed Demand for Minimum Load Agreements will be set in the fifth year to no less than 75% of Distribution Capacity and set to recover no less than 17% of the Cost of Work totaled over the five-year load ramp period, provided that for each year during the ramp period the Billed Demand many not exceed the Distribution Capacity. Customers under a Minimum Load Agreement will be billed at the greater of Billed Demand or actual demand.

B. **Contract Term**
The term of a Minimum Load Agreement will be 10 years. The term of the LLCA will be 10~~8~~ to 30 years, at the Customer's election, measured from the in-service date.

C. **Contract Renewal**
Customer Service Contracts will renew automatically unless terminated according to the terms of the Customer Service Contract.

RULE I (Continued)

Customer Service Contracts – Capacity Categories 2B and 3 (Continued)

D. **Credit Requirements**
If Applicant does not meet the Company's credit requirements or does not provide a parental guarantee from a parent company meeting the Company's credit requirements, then Applicant will be required to provide a deposit in the form of a letter of credit. The Company's credit requirements will be identified in the Customer Service Contract.

E. **Exit Fee**
In the event a Customer Service Contract expires or is terminated by the Customer or by the Company in the event of a Customer default or breach or by either the Company or Customer in the event of change of law defined in the Customer Service Contract, the Company will calculate the Exit Fee in a commercially reasonable manner and provide notice of the amount to Customer and Customer shall pay the Exit Fee to the Company within ten (10) calendar days of the date of such notice.

The Exit Fee for the LLCA shall be (i) the net book value of the Cost of the Work calculated as of the date that is three (3) years after the date of termination or expiration of the LLCA, as determined by the Company in accordance with generally accepted accounting principles; plus (ii) any additional costs reasonably incurred or owing by the Company in connection with winding up the construction work, including any costs of decommissioning and removal of the Distribution Facilities, net of salvage value as determined by the Company in its reasonable discretion, and costs incurred in connection with the cancellation of third-party contracts; plus (iii) an amount equal to three years of distribution charges at the then current tariff rates for distribution and equal to either Billed Demand or actual demand (if there is no Billed Demand) as applicable to the Customer at the time of termination or expiration of the LLCA. If a CIAC is paid by Customer, the net book value of the Cost of Work shall be reduced accordingly for the purpose of calculating the Exit Fee.

The Exit Fee for the Minimum Load Agreement shall be (i) the net book value of the Cost of the Work calculated as of the date of termination or expiration of the Minimum Load Agreement, as determined by the Company in accordance with generally accepted accounting principles; plus (ii) any additional costs reasonably incurred or owing by the Company in connection with winding up the construction work, including any costs of decommissioning and removal of the Distribution Facilities, net of salvage value as determined by the Company in its reasonable discretion, and costs incurred in connection with the cancellation of third-party contracts.

RULE I (Continued)

Customer Service Contracts – Capacity Categories 2B and 3 (Continued)

F. **Failure to Satisfy Flexible Load Requirements**
The Customer Service Contract will contain terms and conditions providing for remedies if a Customer fails to satisfy the requirements for its participation in any Company-approved flexible load program when such participation is a condition of service. Customers who are enrolled in a flexible load program with the Company as a condition of service are not eligible for financial benefits associated with such programs so long as participation in the Company approved flexible load program is a condition of service.

G. **Capacity Exceedance Penalty**
Under the terms of any LLCA or any Minimum Load Agreement for Allocated System Capacity of 12 MW or greater, if the Customer's actual demand exceeds Allocated System Capacity by 10% or 5,000 kW, whichever is less ("Capacity Exceedance Threshold"), then the Customer will be assessed an exceedance penalty. The penalty amount will be calculated and charged per hour and per MW of exceedance over the threshold as four times the transmission rate specified by demand per the retail schedule under which the Customer is served. Customers who exceed their Capacity Exceedance Threshold will be subject to curtailment, termination and other remedies specified in the Customer Service Contract.

H. **Minimum Transmission Demand**
LLCAs will require Customers to annually meet or pay a minimum of 80% of Allocated System Capacity (the "Minimum Transmission Demand") at the then current tariff rate for transmission per the retail schedule under which the Customer is served.

I. **Minimum Generation Demand**
LLCAs will require Customers to annually meet or pay a minimum of 80% of Allocated System Capacity (the "Minimum Generation Demand") at the then current tariff rate for generation per the retail schedule under which the Customer is served.

~~I.~~J. **System Capacity Allocation Deposit**
LLCAs will require Applicants provide a one-time deposit for Allocated System Capacity equal to two years' worth of Minimum Transmission Demand. Customers with no arrearage will be entitled to a refund of the System Capacity Allocation Deposit. Eligible refunds will be paid at 50% following Year 2 and 50% following Year 3 of the Customer Service Contract.

~~J.~~K. **Subject to Revision**
For any Customer Service Contract signed after April 16, 2025 and before [insert effective date of revised compliance tariff based on UM 2377], all contract terms are subject to change pending and based upon Commission final orders in Commission Docket Nos. UE 430 and UM 2377.

RULE I (Continued)

Customer Service Contracts – Capacity Categories 2B and 3 (Continued)

~~K.~~L. **System Capacity Allocation Period**

Under the terms of any LLCA, Allocated System Capacity is determined on a rolling three-year basis until the termination or expiration of the LLCA. At the end of each allocation period, the allocation will auto-renew at the Allocated System Capacity unless, (1) the Company has reduced the Allocated System Capacity due to failure to meet the Minimum Transmission Demand at least three (3) times in the immediately preceding allocation period, (2) the customer has requested a reduction of their Allocated System Capacity and the Company has accepted the reallotment of system capacity to another customer, or (3) the Customer fails to meet the requirements of the Flexible Load Plan, as defined in the LLCA.

If Customer's Demand fails to meet the Minimum Transmission Demand as outlined in the LLCA at least three (3) times in the immediately preceding allocation period, then the Company may reduce the Allocated System Capacity to Customer's highest Demand measured during such allocation period pursuant to the terms of the LLCA. The terms and conditions applicable to potential reductions in Allocated System Capacity based upon the Customer's failure to satisfy the requirements of any Company flexible load program or upon the Customer's timely request to reduce the Allocated System Capacity will be set forth in the LLCA. The Customer will not be required to pay a new System Capacity Allocation Deposit at commencement of each allocation period, but transmission charges will be based upon the Minimum Transmission Demand established for the three-year period.

Customer requests for reductions of Allocated System Capacity and their accompanying cost responsibilities will only be considered at the expiration of each three-year allocation period and will be contingent upon the Company's ability to reallocate such capacity to another customer. Capacity reallocation will be allowed if either of the following conditions are met:

(1) The assuming customer is at the same physical location and has the same electrical point of connection to the transmission grid as the customer requesting the capacity reallocation; or
(2) The assuming customer(s) is(are) at a different physical location, and the Company determines that reallocation is feasible through a study that checks electrical proximity and effects on the transmission system. Feasibility is met if the Company determines that the new physical location and electrical connection are not adversely impactful to power flow and network topology. The study will be provided to Staff of the Public Utility Commission of Oregon.

RULE I (Continued)

6. Refunds

A. Where an Applicant has paid all or a portion of the costs of a Line Extension and additional Customers are subsequently connected to it, the Company will, at its initiative or on request from the Applicant for the original Line Extension, compute on a prorated basis the Line Extension Cost responsibility for up to three additional new Applicants connected to the original Line Extension and make collections and refunds for up to three additional Applicants, provided the following three conditions are satisfied:
   1) The original Line Extension has been in service for less than five years when the additional connections are made;
   2) The original Line Extension has been in service less than six years when the application for refund is made; and
   3) The payment made by the original Applicant was $100 or more.

B. Where additional Applicants are connected within five years of completion of the original Line Extension, and the allowances for the subsequent Line Extensions exceed additional Applicants' costs, the difference may be refunded to the original Applicant under the following conditions:
   1) Application for such refunds may be made as additional Applicants are connected, but no more frequently than on an annual basis; and
   2) The total amount refunded will not exceed the Line Extension Cost paid by the original Applicant.

7. Special Conditions for Portland River District Undergrounding Project

For an area within the City of Portland, depicted as the shaded region on the map included as Appendix A[(1)], the applicable Applicant cost responsibilities of Underground Line Extensions, as specified in Section (3)B(1), will be incurred as a Service Connection Charge. This charge will be equal to $39,040.00[(2)] for a standard 200' X 200' block within the district. For any development area other than the standard size, the charge will be prorated based on the comparative size of that area.

(1) Between Broadway and Glisan Street and behind Union Station, the River District boundary is defined by the railroad right-of-way. Their respective streets or the Willamette River defines all other sections of the River District boundary.

(2) This amount will be applicable through the year 2009. Beyond 2009, the charge will be escalated annually by the Company's then authorized cost of capital.

8. Conversion from Overhead to Underground Service

A. **General**

The Company will replace overhead with underground Facilities whenever such conversion is practicable and economically feasible. Customers connected by overhead Distribution Facilities owned by the Company that desire underground service will comply with applicable provisions of this rule.

RULE I (Con<u>tinued</u>~~cluded~~)

Conversions from Overhead to Underground Service (Continued)

B. **Payment for Service Changes**

The party requesting conversion from overhead to underground will pay the Company, prior to conversion, the estimated original cost, less depreciation, less salvage value, plus removal expense of any existing overhead Facilities no longer used or useful by reason of said underground system, and the costs of any necessary rearrangements, modifications, and additions to existing Facilities to accommodate the conversion of Facilities from overhead to underground.

C. **Special Conditions**

The conversion of overhead to underground Facilities affecting more than one Customer will be conditioned on the following:

1) The governing body of the city or county in which the Company's Facilities are located will have adopted an ordinance creating an underground district in the area in which both the existing and new Facilities are and will be located, providing:
   a) All existing overhead communication equipment and Distribution Facilities in such district are removed;
   b) Each Customer served from such electric overhead Facilities will, in accordance with the Company's rules for underground service, make all necessary electrical facility changes on said Customer’s Premises in order to receive service from the Company’s underground Facilities as soon as available; and
   c) The Company is authorized to discontinue its overhead service on completion of the underground Facilities.
2) All Customers served from overhead Facilities will agree in writing to perform the wiring changes required on their Premises so that service may be furnished in accordance with the Company's rules regarding underground service. Such Customers must also authorize the Company to discontinue overhead service upon completion of the underground Facilities.
3) The local government requires the Company to convert overhead Facilities to underground at the Company's expense, the provisions of OAR 860-022-0046 will apply.
4) That portion of the overhead system that is placed underground will not impair the utilization of the remaining overhead system.

D. **Cost of Area Conversions**

Area conversions may involve an assessment of costs and responsibilities among Customers. Such assessment and collection thereof will be the responsibility of a governmental unit or an association of those affected.

RULE I (Continued)

Conversions from Overhead to Underground Service (Continued)

E. **Cost of Additional Circuit Capacity**

Where the Company installs an underground circuit with capacity in excess of the existing overhead, any additional cost to provide such excess circuit capacity will be at the Company's expense. Applicant cost responsibilities will be as defined in Section (6)(B) plus all reasonable costs for conduit or vault space installed to establish pathways for future circuit capacity.

9. Nonpermanent Line Extension

A. **General**

A Line Extension is nonpermanent when the Company believes service for its intended purpose by the Applicant will continue for less than five years. If the Company believes a requested Line Extension is nonpermanent, the Company will require a cash advance of the entire Line Extension Cost, plus payments to third parties for easements and those costs outlined under Section 3, plus the estimated cost of removing the Line Extension, less any salvage value. If service is used for the intended purpose by the Line Extension Applicant for a period of five years, that portion of the amount advanced by the Applicant which was in excess of the amount that would have been charged for a permanent Line Extension will be refunded to the Applicant with interest.

B. **Nonresidential Nonpermanent Service – Capacity Categories 1 and 2A**

Nonresidential Line Extension Applicants with Line Extension Costs of $50,000 or greater, with loads in excess of 1 MWa, will sign a contract agreeing to accept Electricity Service at a specified minimum load. If service is terminated within an initial term of five years or if service is reduced to shut-down mode, a Service Termination Charge equal to the Line Extension Allowance (LEA) less 1/5th for each year service was taken at the specified minimum will be assessed as follows:

$$\left[\frac{(5 - \text{Years Served}) * \text{LEA}}{5}\right]$$

10. Excess Capacity

Excess Capacity will be determined to exist where:

A. The characteristics of the Customer's load require the Company to install Facilities larger than the kVA demand of the load for voltage regulation or other reasons;
B. The Customer requests additional capacity due to planned expansion needs that have not yet occurred; or
C. The Customer requests Facilities that are in excess of what the Company determines is required based on the Company's analysis of the Customer's planned load.

RULE I (Concluded)

Excess Capacity (Continued)

E. When a Customer applying for a service upgrade or a new service Applicant requires Excess Capacity, such installation will be ineligible for a Line Extension Allowance associated with the unused or underutilized portion of the Line Extension. The unused or underutilized portion of the Line Extension will be determined by comparing the cost of the Line Extension with and without the Facilities necessary to serve the Excess Capacity. The Customer or Applicant will also be responsible for a maintenance charge equal to the present value of future maintenance of the excess Facilities at the time the new service or service upgrade is installed. If within five years of installation the excess capacity situation is determined to no longer exist the Company will refund the portion of the Line Extension charges that resulted from the designation of Excess Capacity, including the maintenance charge. It is the responsibility of the Customer to inform the Company as to the change in their capacity requirement within the five-year period.

11. Rules Previously in Effect

Amounts advanced under the conditions established by a rule or contract previously in effect will be refunded in accordance with the provisions of that rule or contract.

RULE I

APPENDIX A