Portland General Electric Company
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February 29, 2024

Via Electronic Filing

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

RE: **UM 2024 – AWEC's Investigation Into Long-Term Direct Access Programs**

Dear Filing Center:

Enclosed for filing in the above-referenced docket is Portland General Electric Company's direct access straw proposal.

Thank you in advance for your assistance.

Sincerely,
/s/ *Riley Peck*
Riley Peck
Senior Manager
Resource & Regulatory Strategy

RP/bp

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2024

In the Matter of ALLIANCE OF WESTERN ENERGY CONSUMERS, Petition for Investigation into Long – Term Direct Access Programs.	**PORTLAND GENERAL ELECTRIC COMPANY'S STRAW PROPOSAL**

I. INTRODUCTION

Portland General Electric Company (PGE) respectfully submits this Straw Proposal on long – term direct access (LTDA) issues. LTDA is a longstanding framework in Oregon's energy policy landscape which, when thoughtfully designed, can provide options to large customers. The framework must also recognize and minimize shifting of costs and risks to cost of service (COS) customers, be compatible with regional resource adequacy (RA) requirements, and support Oregon's energy and climate policies. This docket and AR 651, a related rulemaking, could bring significant changes to LTDA, most notably adding preferential curtailment as an option for some LTDA loads. PGE supports modifications to LTDA that achieves the program's objectives of protecting COS customers and creating thoughtful options for LTDA customers consistent with the state's overall energy policy.

Section II of this Straw Proposal addresses preferential curtailment policy issues, including customer election, eligibility, customer curtailment, liability, and uncommitted supply demonstration and pricing. Section III focuses on preferential curtailment implementation, including Electricity Service Supplier (ESS) failure, curtailment protocols, demand response, and curtailment infrastructure. Section IV discusses transition adjustments and bypassed costs. Section V addresses program caps. Finally, section VI discusses other issues, including the election window, updates to emergency default service, returning to COS, and the importance of strong RA requirements for ESSs.

PGE highlights a few essential features in the Straw Proposal:

- *A preferential curtailment program must protect COS customers*. Any preferential curtailment program must allow PGE to immediately and directly shed curtailable load; otherwise, the risk of load shed of COS customers increases. Similarly, any "uncommitted supply" rate must fully collect all incremental costs from curtailable LTDA customers, including costs that may be difficult to quantify.

- *Maintain the existing 300 MWa cap for LTDA load*. In prior phases of this docket and AR 651, it was suggested that preferentially curtailable LTDA load might need to be subject to a different cap, or no cap at all. While preferential curtailment partially mitigates some of the risks that justify PGE's LTDA cap, many risks to COS customers would increase if the cap were increased.

- *Critical customers should be excluded from preferential curtailment*. PGE strongly opposes allowing critical customers such as hospitals or 911 call centers to participate in preferential curtailment, even with a waiver from the Commission.

- *LTDA program features cannot substitute for a rigorous resource adequacy requirement*. Concepts like preferential curtailment and uncommitted supply inherently shift an ESS's fundamental obligation – to actually provide physical power when needed by the customer – to PGE. If an ESS and PGE are subject to equivalent resource adequacy requirements, the ESS should be well-positioned to meet its fundamental obligations and some of the risks associated with these new concepts may be mitigated. But if an ESS is not required to participate in a comprehensive resource adequacy program, PGE's COS customers would face an unreasonable shifting of cost and risk from the ESS.

II. PREFERENTIAL CURTAILMENT POLICY ISSUES

A. Eligible LTDA customers may be preferentially curtailable after installation of necessary equipment and execution of an agreement.

LTDA customers interested in the preferential curtailment program would submit a request, likely on a timetable aligned with the existing annual LTDA election window. PGE will review the request to determine eligibility and work with the customer to identify all infrastructure needed to effectuate preferential curtailment. Then, PGE and the eligible customer will enter into a preferential curtailment election agreement that lists the service points covered by the agreement and the customer will need to pay for the needed infrastructure. The customer will be preferentially curtailable after the infrastructure is installed and passes tests PGE determines to be necessary and after all contractual requirements are met.

B. Preferential curtailment eligibility should be based on customer type and technical feasibility.

1. Critical customers should be excluded from preferential curtailment.

PGE maintains that critical customers should not be eligible for preferential curtailment, even if back-up service is available.[1] Under PGE's existing policy, critical customers – such as hospitals, 911 call centers, and wastewater treatment plants[2] – are excluded from rotating outages to the maximum extent possible, as they are essential for public health and safety.[3] Given that existing policies protect these customers from curtailments to the maximum extent possible (even when the customer is protected by multiple levels of backup), there are no compelling reasons to adopt a different policy for LTDA customers with critical facilities. Voluntarily disconnecting critical infrastructure would inherently (and unnecessarily) increase risks for our communities. Additionally, it would be unfair to ask a PGE employee to disconnect a hospital, 911 call center, or wastewater plant without contemporaneously confirming that a backup is online and fully available. Incorporating extra time into the preferential curtailment process to accommodate this verify action is infeasible.

2. *Service points will be preferentially curtailable only if technically feasible.*

As PGE continues to develop its preferential curtailment technical policies, it is likely that the company will identify general categories of service points as "infeasible to curtail" based on technical or cost – prohibitive limitations. PGE must maintain flexibility to do so and update its policies as needed.

C. Contractual curtailment should not be relied upon.

In the AR 651 docket, the Alliance of Western Energy Consumers (AWEC) proposed that "preferential curtailment could be effectuated through contractual means rather than physical [disconnection by PGE]," requiring direct access customers to "self-curtail their load or face substantial financial penalties."[4] PGE opposes this proposal because it is not practical and creates reliability risks. For example, PGE may need to call on curtailable customers to curtail load during significant system reliability emergencies, which may include an Energy Emergency Alert (EEA). If the customer does not self-curtail on a timely basis, or at all (*i.e.*, decides to accept financial penalties instead of self-curtailing), it could materially increase the likelihood of negative system impacts, such as a load shedding event. In PGE's view, not even the most "substantial financial

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[1] *See In the Matter of Rulemaking Regarding Direct Access Including 2021 HB 2021 Requirements,* Docket No. AR 651, Portland General Electric Comments on Direct Access Rulemaking at 6-7, (Mar. 31, 2023), available at: https://edocs.puc.state.or.us/efdocs/HAC/ar651hac111122.pdf.

[2] PGE, Rule C – Conditions Governing Customer Attachment to Facilities, 8.A. Service Restoration, Generally, C-10, January 1, 2024, available at: https://assets.ctfassets.net/416ywc1laqmd/5SfZZl4LC1xf9xctCK3Aqr/79b1326041f513c8f299a25c30704a9b/Rule_C.pdf.

[3] *Id*., 2.B. Short Term Emergency Curtailment, C 1-2.

[4] *In the Matter of Rulemaking Regarding Direct Access Including 2021 HB 2021 Requirements*, Docket No. AR 651, Comments of the Alliance of Western Energy Consumers at 3, (Sept. 15, 2022), available at: https://edocs.puc.state.or.us/efdocs/HAC/ar651hac153535.pdf.

penalties" provide adequate protection for other customers, who may lose power if self-curtailment is not effectuated timely and when needed.

D. Customers may have the ability to change curtailment options annually if there will be no negative impacts to other customers.

PGE proposes that LTDA customers have the option to change curtailment options on an annual basis, which would limit the required administration including contract management and database updates. However, if there are unique local or constraint issues, the ability to switch designation to or from preferential curtailment may be restricted at the discretion of PGE. In any case, a customer will remain non-curtailable until all needed infrastructure has been installed, passed all testing, and all contractual requirements are met.

E. PGE should not be held liable for curtailment decisions.

Preferentially curtailable customers voluntarily forfeit access to PGE's traditional role as the provider of last resort for their load. This decision should not be taken lightly and must be with full recognition of the risks the customer is assuming. To be clear, in choosing to be preferentially curtailable, customers are voluntarily assuming *all risk* – foreseen and unforeseen – associated with uncommitted supply and curtailment. It would frustrate the purpose of a preferential curtailment program if customers could later claim that PGE could have, or should have, served them.

Accordingly, neither the customer nor the ESS should be able claim that PGE is liable for uncommitted supply determinations or curtailment; in all cases in which the preferential curtailment program is implemented, PGE must be held harmless and indemnified for any damages resulting from such curtailment. The customer must agree to absorb all costs associated with serving the direct access load with uncommitted supply, including risks associated with procurement and imbalance. It is essential that the Commission clearly articulate this risk allocation in the policy decisions for this docket so that customers and all other stakeholders are given notice. Additionally, PGE intends to include liability and indemnification language in the preferential curtailment election agreement.

F. Even with best efforts, it is not likely that uncommitted supply will be available at times when needed despite best efforts.

OAR 860 – 038 – 0290(9) requires electric companies to make "best efforts" to serve preferentially curtailable customers with "uncommitted supply" prior to curtailment. "Uncommitted supply" means "generation reasonably available to the electric company in the market or through the electric company's own resources. Uncommitted supply "excludes any generation needed to meet the electric company's firm load service obligations, anticipated nearterm load obligations, contractual obligations, and federal reliability standards."[5] It is worth noting that the market conditions that may lead to ESS failure – and invocation of a preferential curtailment – likely overlap with situations where PGE would be using every available resource, including all available market purchases, to serve its COS load. Thus, it is possible that even with best efforts, preferentially curtailable customers will not have access to "uncommitted supply."

G. Demonstrating that PGE made best efforts to serve preferentially curtailable customers with uncommitted supply should be based on clear criteria.

PGE highlights that the process to determine if uncommitted supply is available should be based on clear criteria. To this end, PGE suggests that the availability of uncommitted supply should be presumptively dependent on:

- PGE's ability to pass resource sufficiency tests for all relevant energy markets;

- the company's ability to fulfill its Western Resource Adequacy Program (WRAP) obligations, both binding and non-binding; and

- the sufficiency of PGE's available import capacity.

If PGE is unable to meet any of these criteria, uncommitted supply is *per se* unavailable. Further, if these criteria are met, PGE should retain the ability to demonstrate that uncommitted supply was in fact not available, with a presumption that the company's determination was reasonable.[6] As discussed in Section II.E., PGE should not be liable to a curtailable customer if the company determines that uncommitted supply is not available.

H. The price paid for uncommitted supply should incorporate all incremental costs.

OAR 860-038-0290(11) requires that any uncommitted supply be priced at the higher of the "incremental capacity and energy costs or a market rate." Conceptually, this appears to create a pass-through mechanism, making the preferentially curtailable customer responsible for whatever incremental costs are attributable to their unexpected return – either costs of dispatching PGE's own resources or of market purchases to serve the customer.[7] There are two market-based aspects to determining how much a customer should pay for uncommitted supply: first, the rate, and second, the quantity of supply procured on behalf of the customer at that rate.

[5] OAR 860-038-0005(42).
[6] For example, it is possible that uncommitted supply may be unavailable, even if PGE passes all relevant tests and has sufficient transfer capacity, due to tag curtailments or plant/transmission contingencies.
[7] PGE suggests that the rate should be based on market prices, not the incremental cost of the company's own energy and capacity because, even if PGE's own generation is "uncommitted," by delivering it to the curtailable customer, the company would be losing out on the ability to sell that generation on the market at the market price.

First, to determine the uncommitted supply rate, PGE proposes including the price of four distinct cost drivers:

- *Energy pricing:* The energy price component would be set at 150 percent of the higher of Mid-C or EIM actuals for the period in which the returning customer was served. PGE recommends including the 50 percent adder to account for premiums associated with physical energy purchases and overhead. Alternately, a per-MWh premium would also respond to the same concerns.

- *Capacity pricing:* The capacity component should be based on actual market costs, as those costs change over time. We recommend considering use of the WRAP forward showing deficiency charge (the Cost of New Entry (CONE) charge).[8]

- *Transmission and ancillary services:* This charge would recover the cost to deliver purchased power to the preferentially curtailable customer. Pricing this element at the Bonneville Power Administration (BPA) tariff price for daily, weekly, or monthly firm transmission service, plus the cost of BPA ancillary services, would accurately collect those costs.

- *Policy compliance adder:* A number of state policies, including the renewable portfolio standard (RPS), HB 2021 compliance, and small-scale resource mandate, add costs that increase as PGE's load increases. Serving preferentially curtailable customers' load with uncommitted supply increases PGE's load. Therefore, these costs should be included in any uncommitted supply rate and all supplemental rate schedules should apply.

Second, to determine the quantity of supply procured on behalf of the preferentially curtailable customer, PGE proposes to charge based on the forecasted load that PGE uses to determine the quantity of supply procured on behalf of the customer. That forecast – not actuals – drives PGE's purchasing and, therefore, costs incurred.

Finally, PGE notes that providing uncommitted supply will become more complex in the future. After 2030, finding resources for preferentially curtailable customers may require PGE to source energy from unspecified sources, which carry a carbon emissions component. Incurring carbon emissions to serve preferentially curtailable customers could imperil PGE's compliance with HB 2021 and may change the company's dispatch decisions for the remainder of the

[8] Western Resource Adequacy Program Tariff of Northwest Power Pool D/B/A Western Power Pool, section 17, available at:
https://www.westernpowerpool.org/private-media/documents/WRAP_Tariff_12-12-22_W0327945x8DF47_2.pdf.

compliance year. While resolution of this issue is not immediately necessary, it is worthy of later consideration in this docket or a future proceeding.

III. PREFERENTIAL CURTAILMENT IMPLEMENTATION ISSUES

A. Defining "ESS failure" should be based on stated criteria, and resumption of normal service should depend on the ESS.

Preferential curtailment is intended to provide an alternative to PGE's provider of last resort obligations when an ESS fails to serve its LTDA load in PGE's Balancing Authority Area (BAA). At this point, PGE proposes several principles for defining ESS failure, with specific operational details to be defined at a later point:

- *PGE must receive notice of ESS failure in advance of real-time.* PGE must have sufficient time to procure uncommitted supply or initiate preferential curtailment.

- *Determination of ESS failure must be based on stated criteria.* All parties – PGE, the ESS, and the preferentially curtailable customer – must know, without any ambiguity, what ESS actions will trigger preferential curtailment or provision of uncommitted supply, if available.

- *The preferentially curtailable customer is responsible for all PGE costs associated with uncommitted supply.* Depending on ESS scheduling practices and when PGE receives notice that the ESS will resume delivering energy to PGE's BAA, it is possible that PGE may have procured uncommitted supply at the same time that the ESS is resupplying its customer. In this case, PGE's imbalance costs will likely increase. The preferentially curtailable customer should bear the costs of the uncommitted supply and any associated imbalance charges.

- *Repeated ESS failure should be grounds for decertification.* Regardless of whether a DA customer is preferentially curtailable or not, ESSs have a basic responsibility to serve their customers' load. If an ESS does not fulfill that basic responsibility, PGE will consider recommending that the Commission decertify an ESS, consistent with current rules.

- *Preferential curtailment is not a replacement for Open Access Transmission Tariff (OATT) charges and practices.* When an ESS's deliveries do not perfectly match its load, PGE makes up that difference (positive or negative) with its own resources and market purchases and charges the ESS an OATT rate. It is important that OATT charges that recover these costs are set at a level that discourages ESSs from leaning on imbalance or other BAA services, which may require FERC changes. PGE looks forward to continuing to discuss how the OATT remedies interact with preferential curtailment in future stages of this proceeding.

B. Preferential curtailment will be accomplished with existing load shed protocols.[9]

Initially, PGE proposes to set up energy blocks in the Advanced Distribution Management System (ADMS) consisting of each ESS's preferentially curtailable service points. Before initiating preferential curtailment, PGE will attempt to serve these service points with uncommitted supply. If uncommitted supply is not available or becomes unavailable, then PGE will curtail preferentially curtailable load served by the ESS that failed. If a preferential curtailment overlaps with a PGE load shed event, any ADMS energy block of preferentially curtailable customers that has been curtailed will remain deenergized until normal service is restored.

Given the complexity of implementing preferential curtailment, PGE suggests that an annual test of systems—including a brief customer curtailment—would be advisable.

C. Demand response and preferential curtailment serve different purposes.

While demand response and preferential curtailment both reduce load in the PGE BAA, they are implemented with different customer and utility actions, require distinct equipment, and operate within different regulatory contexts.[10] Demand response is not, and should not become, a tool for LTDA customers to avoid curtailment during critical system emergencies. Likewise, demand response should not become a tool to manage ESS failure in a preferential curtailment program.

PGE does not have a mechanism to offer direct access customer participation in a demand response program since direct access customers' electricity demand is served by a separate entity.[11] The purpose of demand response is to temporarily reduce a load-serving entity's load so a limited amount of electricity can be redirected to other customers. Because PGE is not a LTDA customer's

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[9] PGE, Rule C – Conditions Governing Customer Attachment to Facilities, 2.B. Short Term Emergency Curtailment, C 1-2, January 1, 2024, available at: https://assets.ctfassets.net/416ywc1laqmd/5SfZZl4LC1xf9xctCK3Aqr/79b1326041f513c8f299a25c30704a9b/Rule_C.pdf.

[10] *In the Matter of Rulemaking Regarding Direct Access Including 2021 HB 2021 Requirements,* Docket No. AR 651, *see* Portland General Electric Comments on Staff's Updated Preferential Curtailment Proposal at 7, (Feb. 3, 2023), available at: https://edocs.puc.state.or.us/efdocs/HAC/ar651hac163051.pdf. Demand response and curtailment are distinct. Demand response is a traditional utility energy and capacity resource asset deployed as part of a generation stack of services optimized to serve customer demand during peak periods. By contrast, curtailment is implemented exclusively during critical grid health emergencies when demand surpasses the operational capacity of the system. Curtailment events are unscheduled, duration is not known, and terms of participation are not variable; events are default and mandatory due to the severity of the immediate grid conditions. On the other hand, demand response is a customer load modification scheme that is voluntary and within control of the customer. Further, demand response is variable in its energy reduction and defined in event duration. In general, demand response events are scheduled and known.

[11] This includes both LTDA customers and all other customers on different PGE direct access programs.

load-serving entity, a reduction in a LTDA customer's load would not free up PGE-owned electricity to serve other customers. Additionally, the program would not reduce PGE's costs to provide electricity during peak periods (a significant purpose underlying demand response). Therefore, even if equipment needed for preferential curtailment could also effectuate demand response, there would be no demand response co-benefit unless the LTDA customer returned to PGE as a COS customer.

D. Infrastructure to enable preferential curtailment is customer specific.

To operationalize curtailment, PGE must be able to curtail only the preferentially curtailable service points while maintaining service for other service points at the same feeder. The specific equipment, configurations, investments, and associated cost estimates will be specific to each customer and dependent on the size of the system, nature of connectivity, configuration of service, and whether the system is overhead or underground.

PGE anticipates that additional facilities, poles, vaults as well as engineering and installation would be required for all customers. In many cases, extensive programming and coordination of systems may be required, including Supervisory Control and Data Acquisition (SCADA), Energy Management Systems, and customer systems. Customers served by an overhead system would need a SCADA enabled recloser at each primary metered service point. Customers served by an underground system would need a SCADA enabled pad mounted switch, reconfigurations, and other equipment. Equipment for substation – connected service points and express feeder service points that can be disconnected with existing SCADA distribution breakers or transformer circuit switchers may be minimal.

IV. TRANSITION ADJUSTMENTS AND BYPASSED COSTS

A. Transition adjustments should include ten years of fixed generation costs.

PGE recommends that the Commission extend PGE's transition adjustments for LTDA to allow ten years' worth of fixed generation costs to be recovered over five years. This change will better protect COS customers from unwarranted cost-shifting. PGE has previously proposed modifying PGE Schedule 129 (Long-Term Transition Cost Adjustment) to recover ten years of fixed generation costs in five years of transition adjustments, as the Commission has allowed for PacifiCorp.[12]

PGE's transition adjustment currently collects five years of fixed generation costs over five years, which is insufficient to prevent unwarranted cost shifting. Currently, Long-Term Transition Cost Adjustments in Schedule 129 are calculated for each LTDA schedule by delivery voltage, for

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[12] *In the Matter of Portland General Electric Company Request for General Rate Revision*, Docket No. UE 335, Portland General Electric Direct Testimony and Exhibits of Maria Pope and Jim Lobdell at 712 (Apr. 15, 2018), available at: https://edocs.puc.state.or.us/efdocs/HTB/ue335htb172131.pdf.

an enrollment period, for a particular year, and currently for five years. The calculation takes five years of net variable power costs (NVPC) and adjusts for various PGE supplemental schedules.[13] This results in the Total Part A COS price. The anticipated market value of the power for that year is then deducted from this total, resulting in the Schedule 129 Part A Transition Adjustment for that year. For a LTDA schedule and enrollment window, the five-year Levelized Schedule 129 Part A payment is then calculated.

Schedule 129 Current Part B is the fixed generation costs from the previous general rate case for a particular year. The sum of the Levelized Schedule 129 Part A and Schedule 129 Current Part B results in the Schedule 129 Transition Adjustment for a particular year, which has the potential to be either a cost or a credit. Generally:

- if the difference between the adjusted NVPC and the anticipated market value of the power left behind by the departing customer is greater than that customer's share of the fixed costs of generation, the LTDA customer's transition adjustment is a credit; or

- if the fixed costs of stranded generation are greater than the difference between the adjusted NVPC and the anticipated market value of the power, the transition adjustment is a cost.

Fixed generation costs are a key determinant in whether transition adjustments are a cost or a credit. After five years, the LTDA customer no longer pays Schedule 129 transition adjustments, so any ongoing costs associated with these schedules – including fixed costs – are borne solely by COS customers, while the LTDA customer continues to reap ongoing system benefits associated with fixed generation investments.

PGE has previously raised that there is multimillion-dollar harm to PGE's COS customers in years 6-10 related to long-term opt outs.[14] Based on a conservative assumption of fixed generation not growing from current levels, and LTDA load remaining stable, PGE has estimated harm to remaining COS to be about $70 million. PGE uses the following exhibit to calculate the

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[13] See PGE Schedule 122, Renewable Resources Automatic Adjustment Clause, available at: https://edocs.puc.state.or.us/efdocs/HAC/ar651hac163051.pdf (any deferrals associated with renewable energy resource and energy storage projects not otherwise included in rates), Schedule 135, Demand Response Cost Recovery Mechanism, available at: https://assets.ctfassets.net/416ywc1laqmd/3xXyUze7t3mv5PE4J4pUqh/ee0ba32beca8b7f543dc9cc524f843ef/Sched_135.pdf, Schedule 138.Energy Storage Cost Recovery Mechanism, available at: https://assets.ctfassets.net/416ywc1laqmd/2d3t4JbJmL02fKe4Gm36ng/61e9ca1de96a2b38a678f1ac05efad27/Sched_138.pdf, and Schedule 146,Colstrip Power Plant Operating Life Adjustment, available at: https://assets.ctfassets.net/416ywc1laqmd/1Ytc6YPnaaiGy3M9DZ7fOi/6fdcc47b955f9d9a7b65f486b5a31b85/Sched_146.pdf.

[14] *In the Matter of Portland General Electric Company, Request for General Rate Revision*, Docket No. UE 335, PGE's Direct Testimony and Exhibits of Maria Pope and Jim Lobdell at 713, (Feb. 15, 2018), available at: https://edocs.puc.state.or.us/efdocs/HTB/ue335htb172131.pdf. *See also*, Docket No. UM 2024, PGE straw-proposal for changes to long-term direct access programs at 8-10 (Aug. 23, 2021). available at: https://edocs.puc.state.or.us/efdocs/HAC/um2024hac82045.pdf.

lost fixed generation revenue in years 6-10 resulting from 50 MWa of load departing COS for LTDA:

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total Years 6-10
89-P Fixed Generation ($/MWh) with No Escalation	32.21	32.21	32.21	32.21	32.21	32.21	32.21	32.21	32.21	32.21	
MWa	50	50	50	50	50	50	50	50	50	50	
Annual Energy (MWh)	438,000	438,000	438,000	438,000	438,000	438,000	438,000	438,000	438,000	438,000	
Fixed Generation Decrement	$14,107,980	$14,107,980	$14,107,980	$14,107,980	$14,107,980	$14,107,980	$14,107,980	$14,107,980	$14,107,980	$14,107,980	$70,539,900

Figure 1 – Lost Fixed Generation Revenues from 50 MWa of LTDA Opt-out

PGE continues to estimate based on 50 MWa remaining available under the 300 MWa LTDA cap, so the $70 million figure is indicative of the fixed generation costs that COS customers could be burdened with.

As more customers choose LTDA, remaining COS customers will pay higher prices. As a result, ten years of transition adjustments would not entirely remove the cost shift to COS customers for existing generation resources, but it would contribute more meaningfully than the status quo.

B. Costs bypassed by LTDA should be further discussed.

PGE is subject to a diverse array of mandatory state and federal policy requirements that create costs for its COS customers. Some, but not all, of these policies apply to ESSs, thereby allowing LTDA customers to bypass certain policy costs paid by equivalent customers on COS. PGE believes that LTDA customers avoid costs associated with the following state and federal policy requirements, among others:

- PGE's PURPA purchase obligation
- Net metering
- The community-based renewable energy purchase mandate, ORS 469A.210
- Community solar costs

These, and other bypassed costs, deserve further attention in this proceeding.

V. PROGRAM CAPS

A. Existing caps should be maintained to protect COS customers.

PGE urges the Commission to maintain existing program caps for both curtailable and non-curtailable direct access customers. Caps remain an essential tool to mitigate cost shifting, and reliability impacts from unplanned load shifts. Caps place bounds on potential negative outcomes, particularly where future impacts are "unknown and unknowable."[15] Placing boundaries on unanticipated costs and risks is critically important when operationalizing a new curtailment regime particularly during system emergencies.

In prior phases of this docket and AR 651, there was some suggestion that curtailable LTDA load might not need to be subject to a cap, because the utility would not hold a provider of last resort obligation for that load.[16] However, that change does not justify lifting or eliminating caps because PGE still faces a risk of material load increase, which would increase costs and risks for COS customers.

From a tariff perspective, preferentially curtailable customers will not be eligible for service under PGE Schedule 81, Nonresidential Emergency Default Service, which allows a LTDA customer to purchase electricity from PGE immediately, for up to five business days.[17] However, with five business days' notice, all LTDA customers may choose a Company Supplied Energy Option, priced at Mid-C Daily Average, plus a small administrative fee and losses.[18] This means that if a preferentially curtailable customer is curtailed, it could simply choose the Company Supplied Energy Option and wait five business days and be guaranteed service. During constrained market conditions, it would be extremely difficult to accommodate a significant amount of load returning to the Company Supplied Energy Option on that timeframe – but at this point, PGE has no choice but to serve those customers.

Additionally, preferential curtailment does not reduce the risks related to PGE's overall BAA responsibilities, which are borne almost entirely by COS customers. For example, the significance and magnitude of ESS scheduling deviations increases as LTDA load increases: a five percent deviation between an ESS's schedule and actual delivery to PGE is far more impactful to COS customers if the amount of LTDA load on PGE's system doubles. Similarly, as western markets continue to become more dynamic (see, for example, the evolution and expansion of the Western Energy Imbalance Market (EIM) and the forthcoming launch of at least one, if not two, day-ahead markets) with significant resource sufficiency and transmission availability tests, PGE, via rates paid by COS customers, is continuing to increase the investments it makes that benefit the PGE BAA overall – including LTDA load served by ESSs. Most notably, PGE's Resource Sufficiency Evaluation (RSE) test, which is required due to PGE's EIM participation, is directly

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[15] *In the Matter of Portland General Electric Company, Request for General Rate Revision*, Docket No. UE 335, Order No. 19-128, (Apr. 11, 2019), available at: https://apps.puc.state.or.us/orders/2019ords/19-128.pdf.

[16] *In the Matter of Rulemaking Regarding Direct Access Including 2021 HB2021 Requirements*, Docket No. AR 651, Comments of the Alliance of Western Energy Consumers at 2 (Apr. 21, 2022), available at: https://edocs.puc.state.or.us/efdocs/HAC/ar651hac174442.pdf.

[17] PGE currently effectuates provider of last resort per Schedule 81 (Nonresidential Emergency Default Service): a direct access customer no longer receiving service from its ESS and returning to PGE without the required notice is charged 125% of ICE-Mid-Columbia (Mid-C) Firm Index plus 0.306 cents per kWh for wheeling, plus line losses. PGE Schedule 81, Nonresidential Emergency Default Service, 81-1, available at: https://assets.ctfassets.net/416ywc1laqmd/2ivuPPsBIaRFaHJVYw43MU/eb0847644a04e88c116da8e00d9bbd02/Sched_081.pdf.

[18] See, e.g., Schedule 485, p. 2. Microsoft Word - 485-23-40_E-19 GRC_12_19_23 (ctfassets.net).

related to the total PGE BAA load, including load served by ESSs. Those costs scale as the PGE BAA load increases and are borne by COS customers. PGE believes that taking a measured approach to maintain the caps is prudent and essential to protect COS customers from unforeseen harm.

Finally, PGE notes that LTDA load growth could result in upward pressure to statewide carbon emissions in 2030 and 2035, unlike PGE load growth. HB 2021 sets PGE's 2030 emissions target at 1.62 million metric tons of carbon dioxide equivalent, regardless of how much PGE's load grows. ESS emissions targets are set based on carbon intensity. As LTDA load grows, ESSs can emit more.[19] Maintaining existing caps on LTDA load eliminates the risk that ESS emissions attributable to Oregon customers grow materially; but this would not be the case if the caps are increased or eliminated.

B. The Commission should clarify the operation of the existing LTDA cap.

PGE requests the Commission clarify that PGE's existing LTDA program cap of 300 MWa applies to load growth behind direct access meters: load growth below the cap would be eligible for direct access, but load growth above the cap would be placed on COS rates. Allowing load growth above the program cap to remain eligible for direct access creates a loophole in the LTDA program.

For example, consider a situation in which 1 MWa remains under the 300 MWa cap and a customer opts out of COS when its load is 1 MWa (below the cap). Further assume that the full development plans call for the load to increase 100 MWa (100 MWa above the cap). If the cap did not apply to behind the meter load growth, then all that load growth would be allowed in the LTDA program. Accordingly, PGE's 300 MWa cap would be exceeded by 100 MWa, quietly vitiating the customer protection motivations of the existing cap. PGE strongly believes that the existing cap levels are reasonable and should be maintained. If the caps are to be increased via an exception for behind the meter load growth, at the very least the Commission should do so knowingly and intentionally, not inadvertently.

VI. OTHER ISSUES

A. The LTDA election window should be changed to reduce the risk of cost shifts.

PGE's existing month-long LTDA election window[20] creates an opportunity for participants to shift costs to nonparticipants. To reduce the likelihood of this cost shift, PGE proposes to change the long-term election window from a month-long window in September to a one-week window during the first week in October. PGE also proposes to change the effective

[19] ORS 469A.410.

[20] PGE's LTDA election window is currently open from September 1 through the last business day of September.

date for Sch 129 Long Term Direct Access transition adjustment from September first to October first.

Currently, PGE calculates its transition adjustment at the end of August based on forward market curves. Simply put, the transition adjustment plus the market cost is meant to equal PGE's cost to serve customers. Customers currently have the option to submit a LTDA contract early in the window, and then wait to see if market prices move higher or lower than the transition adjustment. If prices increase, the customer could rescind the LTDA contract and remain on COS. If prices decrease, the customer could move to LTDA, with the difference between the transition adjustment and the market forecast largely borne by COS customers. Since the customer can, in each case, choose the best option without any costs or fees, the current structure of the long-term opt-out provides participants with a "free option" at the expense of nonparticipants.[21] By shortening the length of the election window and changing the date of filing Sch 129 LTDA transition adjustments, the risk is greatly reduced.

B. <u>Emergency Default Service and PGE Supplied Energy Option Pricing should be updated.</u>

PGE proposes to change PGE's Schedule 81 to accurately reflect the cost and risks of providing Nonresidential Emergency Default Service. Per PGE's Schedule 81, a direct access customer no longer receiving service from its ESS and returning to PGE without the required notice, is charged 125% of ICE-Mid-C Firm Index plus 0.306 cents per kWh for wheeling, plus line losses. After five business days (or before) the customer is moved to PGE's standard offering of ICE-Mid-C Firm Index plus 0.306 cents per kWh for wheeling, plus line losses. The customer then can seek a new ESS or purchase from PGE at the Company Supplied Energy Option.

Schedule 81 no longer fairly reflects the costs of providing Emergency Default Service, which is substantially similar to the cost of providing uncommitted supply. PGE proposes that Schedule 81 pricing be updated to be consistent with the methodology for uncommitted supply pricing proposed in section II.H., above.

Relatedly, PGE proposes limiting how long customers may take service under the Company Supplied Energy Option.[22] All LTDA customers have the option of either purchasing from an ESS or purchasing from PGE at the Company Supplied Energy Option rate. PGE serves this load but is prohibited from planning for it.[23] Customers should be on the Company Supplied

[21] *In the Matter of Public Utility Commission of Oregon, Investigation into the Changes Proposed for the 3 and 5 year Cost of Service Opt-Out Program for Large Non-Residential Customers*, Docket No. UE 236, Direct Testimony of Marc Cody (PGE/100) at 5-6, (Nov. 9, 2011) available at: https://edocs.puc.state.or.us/efdocs/HTB/ue236htb125950.pdf.

[22] See, e.g., Schedule 485, at 485-4. Microsoft Word - 485-23-40_E-19 GRC_12_19_23 (ctfassets.net).

[23] *In the Matter of Public Utility Commission of Oregon, Investigation into Integrated Resource Planning Requirements,* Docket No. UM 1056, Order No. 07-002 (Jan. 8, 2007), IRP Guideline 9 p. 19 available at: https://apps.puc.state.or.us/orders/2007ords/07-002.pdf.

Energy Option for no more than three months at a time. A period longer than three consecutive months should result in an additional fee or penalty.

C. LTDA customers should be allowed to return to COS early upon payment of a fee that captures the incremental cost to serve their load.

Presently, LTDA customers seeking to return to COS must provide either two- or three-years' notice, depending on when they initially opted out of COS.[24] This return notification period is important, as it allows PGE time to plan for the returning load and reduces the likelihood that other customers' costs will increase. PGE proposes to allow customers the option to return to PGE's COS with at least a 12-month notification, subject to payment of a charge intended to capture the incremental cost of serving increased COS load.[25] PGE proposes that the early return charge be calculated in a manner substantially similar to the unallocated supply charge. The amount of returning load may need to be limited depending on planning and system operations limitations.

D. Proposed modifications to direct access are not substitutes for demonstrating resource adequacy.

All resource adequacy issues are better addressed in AR 660, or deferred until the Commission adopts final rules for a statewide resource adequacy program.[26] However, important issues crosscut between this docket and AR 660, so PGE offers these general principles for understanding how direct access and resource adequacy issues relate. Generally, a number of novel features proposed in both this docket and AR 660 – preferential curtailment and uncommitted supply among them – attempt to address challenges that a regional or statewide resource adequacy programs tackle more directly. These are creative concepts, and they are worthy of discussion. To be clear, however, these concepts do not solve the resource adequacy challenge; they are neither a substitute to nor an alternative for a comprehensive resource adequacy program. They merely shift risks and costs.[27]

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[24] For example, PGE Schedule 485, Large Nonresidential Cost-of-service Opt-Out (201-4,000kW), Effective for Service on or after January 2023, available at: https://assets.ctfassets.net/416ywc1laqmd/1TbkHDFrg0Z8OR6FeMsagH/4472b0023ccbdb09fc64a5ba41518b54/Sched_485.pdf.

[25] All LTDA customers would remain able to return to COS following a two- or three-year notice period, consistent with existing contracts and Commission orders.

[26] PGE's positions on implementation of a statewide resource adequacy program were presented most recently in comments filed on January 25, 2024. *See, In the Matter of Adoption of Rules Relating to Resource Adequacy*, Docket No. AR 660 (Jan. 25 2024), Comments of PacifiCorp and Portland General Electric Company, available at: ar660hac326429023.pdf (state.or.us).

[27] PGE will not be required to include LTDA load in its binding forward showings in the WRAP. The WRAP binding forward showing load obligation compliance lies with the Load Responsible Entity (LRE) under the WRAP tariff. For DA load, the LRE is the ESS. No LTDA program feature should implicitly decrease an ESS's resource adequacy obligation or shift it to the utility.

If ESSs are not required to meet stringent resource adequacy requirements, it is far more likely that PGE will need to serve them with uncommitted supply or curtail preferentially curtailable customers. These would be bad outcomes with negative implications for customers, markets, and the regional economy. PGE views a strong mandate requiring all load serving entities to participate in a resource adequacy program (either WRAP or a state program with equivalent requirements) as essential to ensuring load service. A strong resource adequacy program significantly reduces the risks that these novel LTDA features create for PGE's COS customers. Without a strong resource adequacy program, the features would impose unacceptable risk.

VII. CONCLUSION

PGE appreciates the opportunity to submit this Straw Proposal and looks forward to further discussion of these issues in later stages of this proceeding.

Sincerely,

/s/ *Riley Peck*
Riley Peck

Senior Manager, Regulatory Strategy