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 STRAW-PROPOSAL FOR CHANGES TO LONG-TERM DIRECT ACCESS PROGRAMS**

I. INTRODUCTION

Portland General Electric Company (PGE) submits this straw-proposal recommending changes to Oregon's long-term direct access (LTDA) programs.

Background

Oregon took a cautious approach to deregulation when it adopted Senate Bill (SB) 1149 more than 20 years ago, requiring utilities to create cost-of-service (COS) options for all retail customers while also incorporating measures intended to prevent cost shifting among participating and non-participating customers. The legislation sought to preserve funding streams for programs with broad societal benefits, such as energy efficiency and low-income assistance, and recognized the need to ensure reliable service by retaining the utility as the "backstop" and provider of last resort (POLR).

In the years since the legislature adopted SB 1149 the public policy landscape has shifted dramatically, with climate change driving a comprehensive rethinking of how we should generate and deliver electricity. This resulted in Oregon's first renewable portfolio standard (RPS) in 2007 (SB 838), followed by a significant acceleration of the standard (SB 1547) in 2016, and most recently this year's passage of House Bill (HB) 2021, mandating that power suppliers achieve zero greenhouse gas emissions by 2040 and reframing the obligations of the Oregon Public Utility Commission (Commission or OPUC) with respect to competitive operations associated with achievement of greenhouse gas goals.

Technological advancements and program innovations both followed and enabled these public policy changes, further altering the relationship between the utility and its customers as programs like net metering, demand response, and storage spread their costs, risks, and benefits beyond the immediate pool of participating customers. This trend will likely accelerate as we transform the system to achieve the clean energy goals required in HB 2021.

As the expectations, imperatives, and technologies that influence the energy system have changed, it has become increasingly apparent that the customer protections originally built into the regulatory framework created to implement SB 1149 are no longer adequate to achieve the ambitious but necessary goals embodied in HB 2021. This leads to the urgent imperative to eliminate loopholes in direct access programs that enable participating customers to avoid paying their fair share of costs for programs and system resources that benefit them. It also requires ensuring that direct access demands on the system are appropriately factored into long-term resource planning and procurement. We must adopt new regulatory mechanisms to address these concerns, reducing cost-shifting within the system and protecting the reliability and integrity of the energy grid.

If we fail to address issues of cost shifting and non-bypassability, we jeopardize the foundational attributes of the essential service of electricity, the safety, reliability, and affordability of the system – and at the same time, undermine the ability of customers to receive the comprehensive clean energy solutions they deserve.

Proposed changes

The changes recommended in this document relate to programs that currently have five years of transition adjustments: the LTDA program with a cap of 300 MWa,[1] and the new-load direct access (NLDA) program with a cap of 119 MWa.[2] PGE looks forward to a robust discussion on the future of these programs at the Commission. Our proposed changes relate to the following areas:

- Expand non-bypassability of costs and risks to cover all customers of LTDA and NLDA;
- Ensure transparency into ESS pricing and enforcement of OAR 860-038-0275(1) and OAR 860-038-0275(4);
- Update non-residential emergency default service provisions and clearly establish that PGE is the energy POLR and appropriately compensated for associated costs and risks;
- Expand transition adjustments to include ten years of fixed costs of generation; and
- Ensure a hard cap on behind-the-meter load growth when the LTDA program or NLDA program reaches their caps (300 MWa and 119MWa respectively).

PGE explains the imperative for the Commission to address each of these proposed changes below, providing regulatory and procedural history as necessary.

In addition to the proposed changes identified in this straw proposal, it is essential that issues associated with resource adequacy are addressed before making wholesale design changes to key elements such as program caps. PGE understands that resource adequacy is being addressed in a separate proceeding—UM 2143—but reiterates the importance of addressing those issues before making substantive changes to direct access programs or concluding this proceeding.

[1] LTDA includes PGE Schedules 485, 489, and 490, with transition adjustments contained in Schedule 129.
[2] NLDA is addressed in Schedule 689, with transition adjustments contained in Schedule 139.

II. LTDA PROGRAM DESIGN CHANGES

A. Expand non-bypassability of costs and risks

Proposed Change: Expand non-bypassability of costs and risks to ensure direct access customers pay for net-metering (NEM), demand response, and storage, among other programs.

The Commission is statutorily required to prevent "unwarranted shifting of costs" from direct access customers to other retail electricity customers.[3] Direct access can harm COS customers through the ability of LTDA and NLDA customers to bypass costs and risks that are then unfairly borne by COS customers ("bypassability"). Expanding non-bypassability to include NEM, demand response, storage, and RPS-related compliance costs for utility market-based pricing options, among other programs would continue the principle applied at both the Commission and the Legislature that costs of policies, for which there is a societal benefit, are borne by all retail electricity consumers regardless of whether they are served by an investor-owned utility (IOU) or an electricity service supplier (ESS). Below is a summary of progress on non-bypassability since UM 2024 was opened, followed by further explanation of our proposal on this topic.

1. Progress on Non-Bypassability

PGE has repeatedly emphasized that mandated costs associated with effectuating public policies should not be bypassed by choosing an alternative energy supplier.[4] Since UM 2024 opened there have been changes in tariffs and legislation that ensure non-bypassability of the costs and risks of certain policies and programs, but it remains possible for LTDA and NLDA customers to bypass the costs associated with NEM, demand response, and storage at a minimum.

On April 23, 2020 PGE filed Advice 20-09 with the Commission, updating tariff Schedule 136 (Oregon Community Solar Program Start-up Cost Recovery Mechanism: costs incurred during the development of the program including prudently incurred costs associated with implementation).[5] The update requested that LTDA and NLDA contribute to the costs associated with Oregon's Community Solar Program's start-up and bill credit rate, which the Commission

[3] ORS 757.607(1).
[4] UM 2024, PGE's Opening Comments at 26-29, filed March 16, 2020, available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAC&FileName=um2024hac154125.pdf&DocketID=21962&numSequence=52; PGE Advice No. 20-09, filed April 23, 2020, retrieved from: https://edocs.puc.state.or.us/efdocs/UAA/adv1112uaa165524.pdf ; and UE 392, PGE's Direct Testimony of Maria Pope and Brett Sims at 15, filed July 9, 2021, retrieved from: https://edocs.puc.state.or.us/efdocs/HTB/ue394htb155528.pdf .
[5] PGE Advice No. 20-09, filed on April 23, 2020, retrieved from: https://edocs.puc.state.or.us/efdocs/UAA/adv1112uaa165524.pdf .

approved in Order No. 20-173 and Advice 20-22.[6] On July 9, 2021, PGE also filed direct testimony in its 2022 rate case (UE 394), proposing "that the costs of two mandated state programs – the solar payment option (feed-in tariff) and demand response – are not bypassed when customers choose long-term and new load direct access."[7] PGE's pricing testimony in UE 394 includes a proposal to ensure the costs of the solar payment option (PGE Schedule 137) are non-bypassable by LTDA and NLDA customers. In UM 2024 we are also proposing to make the costs associated with demand response programs non-bypassable. Non-bypassability was further incorporated into several pieces of legislation that passed the 2021 session of the Oregon Legislature related to transportation electrification, energy burden, energy conservation and weatherization, and other key areas.[8]

2. LTDA and NLDA Customers are able to Bypass the Costs of NEM, Demand Response, and Storage Pilots.

Currently, LTDA and NLDA customers can bypass the costs of net-metering – a legislatively-mandated public policy – leaving these costs to be solely borne by COS customers. NEM customers are compensated at the retail rate, which is above the resource value of solar (RVOS) and the market rate for renewable power. PGE proposes that stakeholders explore ways that the costs associated with legislatively mandated net-metering can be made non-bypassable. As with the methodology that ensured Oregon Community Solar compensation costs became non-bypassable, the difference between retail rate and a market rate could be calculated and the collection of those costs expanded to include LTDA and NLDA customers.[9]

LTDA and NLDA customers are subject to many PGE supplemental adjustment tariffs,[10] but they bypass the costs associated with PGE Schedule 135 – Demand Response Recovery Mechanism (expenses associated with demand response pilots). To the extent that demand response provides system benefits – such as capacity – that accrue to LTDA and NLDA customers, those direct access customers can bypass the associated costs. Furthermore, demand response programs are legislatively mandated for the broader public good, so all customers should support them. The

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[6] UE 380, Order 20-173, retrieved from https://edocs.puc.state.or.us/efdocs/UBC/adv1112ubc153023.pdf . (Costs associated with the Oregon Community Solar Program bill credit rate were directed to be recovered from direct access customers, with the cost recovery methodology to be filed at a later date); PGE Advice No. 20-22, letter issued October 20, 2020, at 2, retrieved from: https://edocs.puc.state.or.us/efdocs/UBF/adv1170ubf13122.pdf .

[7] UE 394, PGE's Direct Testimony of Maria Pope and Brett Sims, PGE/100, Pope-Sims at 15, line 6, filed July 9, 2021, retrieved from https://edocs.puc.state.or.us/efdocs/HTB/ue394htb155528.pdf .

[8] An Act Relating to Energy, HB 3141 §1(4)(a), 81st Oregon Legislative Assembly (2021); An Act Relating to Clean Energy, HB 2021 §(14)(2), 81st Oregon Legislative Assembly (2021). An Act Relating to Public Utilities, HB 2475 §(7)(2), 81st Oregon Legislative Assembly (2021); An Act Relating to Alternative Fuel Transportation, HB 2165 §(2), 81st Oregon Legislative Assembly (2021).

[9] PGE Advice No. 20-22 at 3, letter issued October 20, 2020, retrieved from: https://edocs.puc.state.or.us/efdocs/UBF/adv1170ubf13122.pdf . PGE recovers the above-market costs from all customers, calculated as the difference between participant bill credits and avoided cost of energy in our Annual Update Tariff and Power Cost Adjustment Mechanism.

[10] UM 2024, PGE's Opening Comments at 27, filed March 16, 2020, retrieved from: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAC&FileName=um2024hac154125.pdf&DocketID=21962&numSequence=52 .

Oregon Legislative Assembly has found that "Demand response resources…protects the public health and safety and improves environmental benefits[.]"[11] PGE proposes that the costs associated with demand response and storage be made non-bypassable (e.g., PGE Schedule 135 Demand Response Cost Recovery Mechanism and PGE Schedule 14 Residential Battery Energy Storage Pilot).[12]

B. Ensure transparency into ESS pricing

Proposed Change: Ensure ESSs are complying with rules requiring them to publish publicly their indicative rates.

Oregon Administrative Rules (OAR) require ESSs to provide the Commission with a website showing their indicative pricing.[13]

Since ESS rates are not public, this rule is intended to ensure that ESS prices are subject to a minimum level of transparency. The PUC's "ESS Service Supplier & Applications" webpage shows that there are currently six active ESSs, with a column for a link to indicative pricing.[14] One ESS had its application granted this year and is not expected to have posted indicative pricing. Of the remaining five ESSs, only two (Constellation Newenergy and Shell Energy North America) provided links to their indicative pricing, with the remaining three appearing to provide links to generic homepages. To ensure transparency and to comply with the Commission's rules, it is essential that ESSs publish their indicative pricing as required by OAR.

C. Update emergency default provisions and clearly establish that PGE is the [energy] provider of last resort (POLR)

Proposed Changes:

- Update PGE Schedule 81 Nonresidential Emergency Default Service to accurately reflect the costs and risks of providing the service and increase the time from five to ten business days; and
- Clearly establish that PGE is the provider of last resort (POLR) for all retail customers in its service territory, including those served by ESSs. PGE should be appropriately compensated for the actual cost and additional risk of serving as the POLR. While the term POLR is widely used, the Commission should clearly define the term to mean an

[11] ORS 757.054 (2)(b), available at: https://www.oregonlegislature.gov/bills_laws/ors/ors757.html

[12] PGE Schedule 14 is a residential battery energy storage pilot will evaluate the ability of residential batteries to deliver services in support of PGE's electrical system. The battery energy storage pilot offers incentives to allow the Company to manage the charging and discharging of customer batteries with the option for a customer override. The pilot is expected to be conducted from August 1, 2020 through July 31, 2025.

[13] See*:* OAR 860-038-0275(1) and OAR 860-038-0275(4).

[14] OPUC ESS Service Supplier & Applicant's webpage: https://www.oregon.gov/puc/utilities/Pages/Electric-Service-Suppliers-(ESS).aspx?wp4092=l:25, accessed August 23, 2021

IOU offering emergency default service (e.g. PGE Schedule 81) and serving as a backup provider should a direct access customer cease receiving service from its ESS.

1. Change PGE's Schedule 81 to accurately reflect the Cost and Risks of Providing Nonresidential Emergency Default Service

Per PGE's 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. After five business days (or before) the customer is moved to PGE's standard offering (daily market pricing) and has the option of seeking a new ESS.

For example, updating emergency default service to accurately reflect the costs of providing such a service would ensure direct access customers are accurately paying for the costs of returning to PGE without the required notice and without shifting risk to or subsidization from COS customers. In a scenario where an ESS is unable to provide power to a customer, the market could already be constrained and without sufficient supply at Mid-C wholesale market, PGE could then be required to supply the customer from its own resources or elsewhere. This could cost more (or less) than 125% of Mid-C and could expose COS customers to unreasonable price and reliability risks. An appropriate framework for emergency default service would consider the cost of capacity fixed costs and would involve an appropriate planning and compensation structure for the possibility of such events.

2. Clearly Establish that IOUs are the Provider of Last Resort for all Retail Customers in their Service Territory

In recognition that IOUs must non-discriminately provide for all customers, it should be clearly established that PGE is the POLR for all retail customers in their service territory. In response to HB 3633 (2001) PGE designed Schedule 82[15] to "provide back-up service for any direct-access customer that loses its ESS and has not provided PGE with the notice required to receive service under the applicable standard offer service rate."[16] PGE proposed to provide this back-up service on an "as available" basis to "prevent a returning direct access customer from causing PGE to curtail service to other customers who did not go to direct access [...] other customers should not be required to suffer rolling outages to provide emergency default service or pay for standby resources for direct access customers." Staff noted that "[b]ecause PGE remains the *provider of last resort* within its service territory [...] the company is obligated to provide safe and adequate service to all customers within its service area" [emphasis added]. The Commission resolved that "customers who choose direct access should not be limited to default service on an "as available" basis."[17]

The Commission's IRP Guidelines state that an IOU should not plan for LTDA loads served by ESSs. In forming the guidelines, the Commission stated its belief that LTDA customers are

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[15] Nonresidential Emergency Default Service is now provided through Schedule 81.
[16] UM 115, Order No. 01-777 at 38, issued August 31, 2001, available at: https://apps.puc.state.or.us/orders/2001ords/01-777.pdf .
[17] Id.

"'effectively committed to service' under direct access and should be excluded from the IRP load-resource balance over the planning horizon".[18] This means that even though PGE has to be there non-discriminately for all customers in an emergency – such as when a LTDA customer returns to us without the required notice - we are not permitted to plan for LTDA loads in our IRP. These requirements should be re-examined to ensure adequate reliability planning and procurement standards are implemented for all customers.

D. Expand transition adjustments to collect ten years' of fixed costs of generation

Proposed Change: Expand the transition adjustments for LTDA and NLDA to allow ten years' worth of fixed generation costs to be recovered over five years.

This will better protect COS customers from unwarranted cost-shifting potentially caused by only five years of transition adjustments. 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.[19]

1. PGE's Transition Adjustments Collection of Fixed Generation Costs over Five years is Insufficient to Prevent Unwarranted Cost Shifting

The collection of fixed generation costs over five years of transition adjustment were set in the early 2000s when load growth would have been anticipated to provide an offset to the lost sales from customers choosing LTDA. As CUB has stated, "When SB 1149 was passed [in 1999] to create direct access, utility loads had been growing. There was a general belief that if direct access customers picked up the fixed costs for a period of time, that the system would grow into those abandoned resources. Transition costs had to cover the time period before the utility load grew into the fixed costs that were being left behind."[20]

At the time, PGE's 2002 Integrated Resource Plan (LC 33) PGE's projected Medium Growth Forecast estimated an annual growth rate of 2.55% for 2003-2051.[21] Since that time, gains in energy efficiency, changes in codes and standards and prolonged impacts of the Great Recession of 2008 have put energy delivery growth rates across the U.S., and in PGE's area, on a lower trajectory. PGE's most recent IRP load forecast estimates a reference case average annual growth rate of 1.0% for 2020-2050.[22] Given this change in overall load growth, a reassessment of transition charges is warranted. Transition adjustments "compare COS prices with expected

[18] Id.
[19] UE 335, PGE's Direct Testimony at 712, filed April 15, 2018, retrieved from: https://edocs.puc.state.or.us/efdocs/HTB/ue335htb172131.pdf
[20] UM 2024, Citizens' Utility Board Opening Comments at 5-6, filed March 16, 2020, available at: https://edocs.puc.state.or.us/efdocs/HAC/um2024hac151142.pdf
[21] LC 33, PGE's 2002 Integrated Resource Plan at 53 (Table 11).
[22] LC 73, PGE's 2019 Integrated Resource Plan at 102 (Table 4-6), filed July 19, 2019, available at: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=21929

market prices related to generation […]" and "include both fixed generation and net variable power costs [NVPC]."[23] Together, fixed generation costs and NVPC are the total production costs.[24] PGE defines NVPC to include "…wholesale (physical and financial) power purchases and sales (purchased power and sales for resale), fuel costs, and other costs that generally change as power output changes."[25] The transition adjustment for LTDA customers is charged or credited through Schedule 129 – Long-term Transition Cost Adjustment.[26]

Currently, Long-Term Transition Cost Adjustments in Schedule 129 are calculated for an LTDA schedule at a certain delivery voltage, for an enrollment period, for a particular year, and currently for five years. The calculation takes the NVPC from the previous rate case and adjusts for various PGE supplemental schedules.[27] 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 believes that fixed generation costs will grow over the

[23] UE 335, PGE's Direct Testimony and Exhibits of Maria Pope Jim Lobdell at 711, filed February 15, 2018, available at: https://edocs.puc.state.or.us/efdocs/HTB/ue335htb172131.pdf .
[24] Id at 841.
[25] Id at 90.
[26] PGE Rate Schedule 129 – Long-Term Transition Cost Adjustment covers both three year and five year opt-outs.
[27] Schedule 122 – Renewable Resources Automatic Adjustment Clause (any deferrals associated with renewable energy resource and energy storage projects not otherwise included in rates), Schedule 125 – Annual Power Cost Update (estimated adjustments due to changes in PGE's NVPC, corrected as required by Schedule 126), Schedule 137 – Customer-owned Solar Payment Option Cost Recovery Mechanism (costs associated with the Solar Payment Option/Volumetric Incentive Rate pilot not otherwise included in rates) - note that PGE has proposed making Schedule 137 non-bypassable in our 2022 General Rate Case, Schedule 145 – Boardman Power Plant Decommissioning Adjustment.

next few years as fossil fuel plants retire[28] and are replaced by clean resources that support the greenhouse gas reduction goals of Oregon's House Bill 2021 (2021).[29]

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. Based on a conservative assumption of fixed generation not growing from current levels at the time, and no load growth in the customers opting out, PGE has estimated harm to remaining COS to be about $76 million.[30] PGE used the following exhibit to calculate the lost fixed generation revenue in years 6-10 resulting from 50 MWa of load departing COS for LTDA:

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total Years 6-10
89-P Fixed Generation ($/MWh) with No Escalation	34.60	34.60	34.60	34.60	34.60	34.60	34.60	34.60	34.60	34.60	
Mwa	50	50	50	50	50	50	50	50	50	50	
Annual Energy	438,000	438,000	438,000	438,000	438,000	438,000	438,000	438,000	438,000	438,000	
Fixed Generation Decrement	$ 15,154,800	$ 15,154,800	$ 15,154,800	$ 15,154,800	$ 15,154,800	$ 15,154,800	$ 15,154,800	$ 15,154,800	$ 15,154,800	$ 15,154,800	$ 75,774,000

Figure 1-Lost Fixed Generation Revenues from 50 MWa of LTDA Opt-out[31]

PGE has explained that, at the time, 50 MWa remained available under the 300 MWa LTDA cap, so the $76 million figure was indicative of the fixed generation costs that by which COS could be burdened.

[28] All customers should pay for the costs of plants that are retired and decommissioned to meet clean energy targets. To the extent that these costs are not captured in applicable supplemental schedules or transition adjustments (i.e. they are included in base rates) they are bypassable for direct access customers.
[29] An Act Relating to Clean Energy, HB 2021, 81st Oregon Legislative Assembly, 2021 Regular Session. Available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
[30] Id. at 713.
[31] Id. at 942.

As more customers choose LTDA, the 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.

2. PGE's Transition Adjustments should be brought into alignment with other IOUs

Currently, transition charges for PGE and PacifiCorp do not align, with PGE recovering only five years of transition charges and PacifiCorp recovering ten years of transition charges over the same period. The Commission has allowed PacifiCorp to recover ten years of fixed generation costs in five years of transition adjustments. In 2013, PacifiCorp proposed a "customer opt-out charge" (COOC) as part of its transition adjustment for its five-year COS opt-out program.[32] PacifiCorp explained that the charge was "a valuation of the fixed generation costs incurred by the Company to serve customers, offset by the value of the freed-up power made available by the departing customers for years six through 20" adding that it was "necessary to minimize cost shifting to nonparticipating customers when customers in this [five-year cost of service opt-out] program cease paying Base Supply Service […] after five years."[33] The stipulating parties in UE 267 asserted that the "record contains no comprehensive analysis of projected stranded costs beyond the five-year transition adjustment period."[34] However, the Commission found that:

> The Stipulating Parties failed to rebut PacifiCorp's evidence of transition costs, up to approximately $60 million, in years six to ten of the program, and rely too heavily on mere assertions about *how transition costs beyond year five can be reduced or erased*. Moreover, we reject the Stipulating Parties' arguments that PacifiCorp's system load growth will completely mitigate any transition costs.[35] [emphasis added]

It is noteworthy that the Commission found evidence in this case that transition costs extended beyond the five-year transition adjustment period, and that it rejected arguments from the Stipulating Parties in that docket that "load growth will completely mitigate any transition costs."[36]

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[32] UE 267, PacifiCorp's Opening Testimony at 6, filed on June 14, 2013, retrieved from: https://edocs.puc.state.or.us/efdocs/HTB/ue267htb144643.pdf
[33] Id.
[34] UE 267, Stipulating Parties' Joint Post-Hearing Reply Brief at 10, filed July 28, 2014, retrieved from: https://edocs.puc.state.or.us/efdocs/HBC/ue267hbc165746.pdf
[35] UE 267, Order No. 15-060 at 7, issued February 24, 2015.
[36] Id.

3. PURPA Contract Costs Extend Beyond Five Years

PGE is required under federal and state law to enter into contracts with PUC Qualifying Facilities (QFs) and pay them for their power at calculated avoided cost rates.[37] Contracts associated with these "must purchase" obligations can have a term of up to 20 years with 15 years of fixed pricing. While ten years of transition adjustments could still allow direct access customers to avoid much of the costs associated with the PURPA obligations that PGE must absorb, it would more closely align with the burden borne by PGE's COS customers over the life of a QF contract (versus five years).

E. Ensure a hard cap on behind-the-meter growth when the LTDA program or the NLDA program exceed their caps.

Proposed Change: Ensure hard constraints on load growth behind meters if/when the LTDA program reaches 300 MWa and/or the NLDA program reaches 119MWa, requiring that load beyond the cap be split to COS.

PGE's LTDA program has a cap of 300 MWa, and our NLDA program has a 119 MWa cap. These program caps are an essential tool to help mitigate the potential for cost shifting as they place limits on "unknown and unknowable" system impacts and on the amount of load that can bypass any remaining policy costs (such as PURPA, NEM, and demand response/storage pilots). PGE notes that the Commission has observed that it "routinely use[s] caps and limits to place bounds on potential negative outcomes, particularly where future system impacts for a course of action are unknown or unknowable."[38] As the state and the region works to resolve impending resource adequacy issues while decarbonizing the electric system in line with state policy goals, it is imperative that these program caps remain in place. Reinforcing these hard caps will ensure the necessary bounds on potential negative outcomes which could lead to unwarranted cost shifting.

III. CONCLUSION

By its nature, a straw proposal is intended to serve as the basis for dialogue and to provide frameworks for parties to coalesce around a mutually agreeable set of principles and concepts to translate into regulation. PGE offers this proposal in that spirit and appreciates the opportunity to share our ideas and perspectives.

In closing, the company reiterates that our intent is to advocate for necessary measures to modernize the regulatory framework of the direct access program to reflect current conditions,

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[37] For a detailed explanation of PGE's PURPA avoided cost methodology, see: UM 2000, PGE's Response to Stakeholder Questions, filed March 29, 2019, retrieved from: https://edocs.puc.state.or.us/efdocs/HAC/um2000hac16523.pdf

[38] UE 335, Order No. 19-128, issued October 26, 2018, retrieved from: https://apps.puc.state.or.us/orders/2019ords/19-128.pdf

priorities, and public policy goals while protecting all customers. We believe that in order to preserve the ability of eligible customers to access a choice of electricity providers, we must also ensure that all customers equitably contribute to costs of system resources and programs that benefit them and serve the overall public good, whether they opt to participate via cost-of-service or direct access.

The retail electric landscape has changed significantly since direct access laws and programs were first established. The fundamental tenets of fairness and non-bypassability that were included in provisions of SB 1149 remain essential, but the mechanisms to enforce them need to be updated to reflect the modern policy landscape and energy system of today. At the same time, the challenge of climate change has altered the way we evaluate program priorities and benefits. This is illustrated in HB 2021's clarification of provisions relating to the competitive market and the need to promote solutions that further decarbonization while protecting affordability, equity and reliability.

PGE believes the recommendations described above would significantly improve the regulatory framework, to the ultimate benefit of all customers.

Respectfully submitted this 23rd day of August 2021.

/s/ *Nidhi J. Thakar*

Director, Resource and Regulatory Strategy and Engagement