BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 2024

In the Matter of ALLIANCE OF WESTERN ENERGY CONSUMERS, Investigation into Long-Term Direct Access Programs	))))))	CALPINE ENERGY SOLUTIONS, LLC'S CLOSING COMMENTS

INTRODUCTION

Calpine Energy Solutions, LLC ("Calpine Solutions") hereby submits its closing comments to the Public Utility Commission of Oregon ("Commission") in the first phase of this proceeding. It appears that the parties are in general agreement regarding many of the questions presented in this phase of the proceeding. Therefore, Calpine Solutions' closing comments will highlight points where there may be disagreement between the parties and will attempt to clarify certain issues raised by other parties.

An overarching contextual area of disagreement arises from Portland General Electric Company's ("PGE") suggestion, expressed at the outset of its opening comments, that there is a natural monopoly for generation and retail energy service in electricity markets.[1] This belief appears to form the basis for many of PGE's arguments in opposition to direct access. However, it is now well understood that only the transmission and distribution aspect of the electricity

[1] *PGE's Op. Comments* at pp. 1-3.

market is a natural monopoly.[2] There is no natural monopoly over the wholesale generation sector or in the provision of retail service of the generation component of electricity to end-use customers.

Notably, Oregon law expressly reflects the competitive nature of the wholesale and retail generation markets. In Senate Bill 1149, the Legislative Assembly declared that "retail electricity consumers that want and have the technical capability should be allowed, either on their own or through aggregation, to take advantage of competitive electricity markets as soon as is practicable."[3] The law specifically instructs the Commission to "eliminate barriers to the development of a competitive retail market structure" and "to mitigate the vertical and horizontal market power of incumbent electric companies[.]"[4]

PGE argues that effective decarbonization will require the Commission to revive the vertically integrated natural monopoly, but this argument overlooks that numerous other states with aggressive decarbonization goals also allow for robust retail choice programs.[5] Direct access remains important and relevant to Oregon's retail electric customers and comports with the state's other policy objectives.

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[2] *See* Joseph P. Tomain, *The Past and Future of Electricity Regulation*, 32 ENVTL L 435, at 443-63 (2002) (collecting sources in a detailed history of electricity markets, and noting: "Over time, vertically integrated utilities under the traditional rate formula overbuilt, and generation became more costly. Rival producers could produce electricity more cheaply, and certain customers, particularly large industrial customers, brought pressure to bear on utilities to get access to cheaper electricity.").

[3] Or Laws 1999, ch 865 at preamble.

[4] ORS 757.646(1).

[5] For example, California has very aggressive decarbonization goals and offers multiple retail choice options, including robust community choice aggregation, direct access, and behind-the-meter generation programs. *See* CPUC, *California Customer Choice Project: Choice Action Plan and Gap Analysis* (December 2018), https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy__Electricity_and_Natural_Gas/Final%20Gap%20Analysis_Choice%20Action%20Plan%2012-31-18%20Final.pdf.

COMMENTS

1. Response to Assertions Related to Resource Adequacy

All parties to this proceeding appear to agree that resource adequacy is a key issue facing the Commission. However, PGE continues to lodge inaccurate and unhelpful accusations towards electricity service suppliers ("ESS") and direct access customers that require a response.

First, PGE overstates the risks to cost-of-service customers under the Commission's existing provider of last resort policies. PGE suggests that long term direct access customers in the five-year program (referred to herein as "LTDA")[6] and new load direct access ("NLDA") customers can immediately switch back to PGE's generation service to take advantage of PGE's long-term planning for resource adequacy at cost-of-service rates because PGE maintains the provider of last resource obligation.[7] However, as Calpine Solutions already explained in opening comments, the LTDA and NLDA customers returning to PGE's cost-of-service rates service must pay a market-based price for *three years* before returning to PGE's cost-of-service rates.[8] PGE itself acknowledges in a footnote that the LTDA and NLDA customer must pay 125 percent of the market index price for its emergency supply and cannot simply return to PGE's long-term cost-of-service supply.[9] PGE's suggestion that such customers would lean on PGE's long-term planning is therefore incorrect because the customers would pay the actual market prices for three years, not the costs of PGE's long-term generation supply.

The Commission acknowledged the realities of how provider of last resort service protects cost-of-service customers from an immediate return by NLDA and LTDA customers in

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6 PGE Schedules 485, 489, 490, 491, 492, and 495.
7 *PGE's Op. Comments* at p. 10.
8 *Calpine Solutions' Op. Comments* at p. 11; *see, e.g.*, PGE's Schedule 89.
9 *PGE's Op. Comments* at p. 10 n. 24.

Docket No. UE 358. In rejecting PGE's resource adequacy charge (the "RAD"), the Commission's order stated:

> The only explicit scenario PGE has presented to justify the RAD is a very narrow one – an instance where an ESS fails to perform, and no power is available, at any price, in the market for PGE to supply customers with emergency service. As several parties correctly observe, this could only occur where there are dramatic regional shortages of power; accordingly, the solution to this specific regional problem must be new, incremental capacity in the region. PGE, however, has proposed utilizing RAD charges to procure contracts with existing capacity resources. Such action does not serve to address the explicit problem scenario that PGE has outlined to justify the charge.

Unless there is no energy available on the market at any price, the returning LTDA or NLDA customer pays the higher prices available on the market and does not benefit from PGE's planning for resource adequacy until after the next planning cycle. The situation where there is no energy available on the market is very unlikely to occur because price increases would normally decrease demand.

Thus, PGE overstates the rights of LTDA and NLDA customers to return to cost-of-service generation rates and the risks to cost-of-service customers associated with such returns to cost-of-service rates. Moreover, to date, Calpine Solutions understands that no customers have willingly returned to cost-of-service from PGE's five-year program, further negating PGE's allegation that such customers inappropriately utilize PGE's costs of long-term planning paid for by other customers.

Next, PGE continues to make unfounded criticisms of market purchases supported by liquidated damages penalties as a reliable source of supply. Specifically, PGE argues ESSs make no contribution to resource adequacy,[10] and PGE continues to make general assertions that market transactions do not support resource adequacy.[11] However, as demonstrated in Calpine

10 *PGE's Op. Comments* at p. 46.
11 *PGE's Op. Comments* at pp. 19-20.

Solutions' opening comments, the use of liquidated damages contracts to serve direct access loads is equivalent to the "front office transactions" relied upon so heavily by Oregon's investor-owned utilities.[12] PGE has traditionally relied on the very same types of transactions as a reliable source of generation supply to serve cost-of-service customers. For example, the Commission relies on such short-term purchases as the basis for PGE's near-term avoided costs: "PGE considers it appropriate to use expected wholesale power market prices to determine avoided costs for its system due to PGE's significant market purchases . . . . paying market prices to QFs equates to PGE purchasing power on the market, which is consistent with its current operations."[13] It is hard to understand why PGE continues to cast dispersions on the use of liquidated damages market purchases when PGE itself has heavily relied on the same type of contracts for decades.

PGE also continues to mischaracterize the Commission's order in UE 358. According to PGE's opening comments, the Commission "identified that Oregon's current direct access programs have flaws which need to be addressed to ensure that COS customers are not unfairly burdened with supporting a reliable system for all customers" and urges prompt action to address this alleged finding by the Commission.[14] However, the referenced Commission order contains no such finding. Nor would the record have supported such a finding because the evidence demonstrated that PGE and PacifiCorp have long used liquidated damages contracts to reliably serve increments of load at least as significant as Oregon's entire direct access load.[15] Instead, the order stated "[p]arties have put forward credible evidence that the contracts backing ESS

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12 *Calpine Solutions Op. Comments* at pp. 29-30.

13 *Re Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Docket No. UM 1129, Order No. 05-584, at 21 (May 31, 2005).

14 *PGE's Op. Comments* at p. 20.

15 *See, e.g., Calpine Solutions' Opening Brief*, Docket No. UE 358, at pp. 11-12 (Nov. 14, 2019).

supply may in some way support regional RA."[16] As noted further in Calpine Solutions' opening comments in this docket, other regions have allowed for the use of liquidated damages contracts sourced from outside the balancing authority to support resource adequacy requirements.[17]

Furthermore, Calpine Solutions and other direct access parties *agree* that a new set of rules is needed to ensure a better accounting and more efficient use of regional assets given impending capacity shortages in the region. As noted in our opening comments, Calpine Solutions agrees there should be reasonable protections against double counting of capacity resources used in liquidated damages contracts supporting a Load Serving Entity's resource adequacy obligations. It does not appear that any party opposes such a requirement at this time in this proceeding. Such a standard should apply equally to the investor-owned utilities.

2. CUB's Arguments Regarding the Northwest's Wholesale Market Structure Do Not Identify Cost Shifts Under Oregon's Direct Access Law

As it did in UE 358, the Citizens Utility Board ("CUB") makes general assertions that direct access customers are taking advantage of current market dynamics to the detriment of cost-of-service customers.[18] CUB contends that direct access customers only pay the marginal costs of existing resources, and thus shift the fixed cost of these resources to cost-of-service customers. According to CUB, direct access customers unjustifiably enjoy low costs at the Mid-Columbia trading hub that result from the investment in renewable energy resources by Oregon's cost-of-service customers.

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16 *In re Portland General Elec Co, Advice No. 19-02 (ADV 919) New Load Direct Access Program*, Docket No. UE 358, Order No. 20-002 at 11 (Jan. 7, 2020).

17 *Calpine Solutions Op. Comments* at 27; *see also Order Instituting Rulemaking to Oversee Resource Adequacy Program*, CPUC Decision 19-10-021, Rulemaking 17-09-020, 2019 CAL PUC LEXIS 636 at **9-27 (Oct. 10, 2019).

18 *CUB Op. Comments* at 2-5; *see also PGE Op. Comments* at pp. 19-20.

There are a number of problems with these arguments. First, the marginal cost of renewable power is generally zero, but the wholesale market prices displayed in the chart in CUB's comments are clearly more than zero and thus far in excess of the marginal cost of the Oregon utilities' renewable fleets.[19] Second, the low wholesale prices in the region over the past several years have also been heavily influenced by lower than expected natural gas prices, not just acquisition of renewable assets by investor-owned utilities funded by cost-of-service customers. Third, there is no subsidy because under Commission policy PGE and PacifiCorp do not acquire new generation resources to serve the existing LTDA or NLDA customers. Further, the Mid-Columbia market does not consist entirely of energy from PGE-owned and PacifiCorp-owned generation; it is a regional market where power is sold from many different publicly and privately owned electric utilities, as well as independent power producers. Thus, the existence of the market used by direct access customers is not solely due to costs incurred by Oregon cost-of-service customers.

Additionally, these generalized arguments regarding perceived flaws in the wholesale markets do not implicate cost shifts that are proscribed by Oregon's direct access law. The section of the law proscribing unwarranted cost shifts limits recovery to assets stranded by the direct access election. The law provides that the Commission may prevent cost shifts through the imposition of "transition charges" that may include "full or partial recovery of the costs of uneconomic utility investments."[20] In turn, the utility's "uneconomic utility investments" are "all electric company investments, including plants and equipment and contractual or other legal obligations, properly dedicated to generation, conservation and workforce commitments, that were prudent at the time the obligations were assumed but the full costs of which are no longer

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[19] *See CUB's Op. Comments* at 3.
[20] ORS 757.607(2) (emphasis added).

recoverable as a direct result of ORS 757.600 to 757.667, absent transition charges. . . ."[21] Likewise, the "transition charges" the Commission may impose are limited to "a charge or fee that recovers all or a portion of an uneconomic utility investment."[22] The charges authorized are charges for stranded investments PGE or PacifiCorp made to serve the now-departed customers, but CUB's argument does not concern stranded costs caused by the direct access customers.

Instead, CUB's argument is concerned more generally with the structure of the regional wholesale market and a perception that cost-of-service customers in the entire Northwest are indirectly creating the market opportunity for Oregon's LTDA and NLDA customers to purchase power on the wholesale market at what are currently low market prices. While market prices available to direct access customers are currently low, that has not always been the case, and it is not evidence of a cost shift from PGE's or PacifiCorp's cost-of-service customers to LTDA or NLDA customers under Oregon law. It is merely a general circumstance of current market conditions. If capacity became scarce and PGE and PacifiCorp were able to charge a premium price to sell its excess energy in the market, an LTDA customer or NLDA customer purchasing such energy at a high price in the market could not credibly argue that costs were being shifted from it to cost-of-service customers. Instead, such profits would flow through to reduce rates for cost-of-service customers.

In sum, CUB's generalized arguments about the wholesale markets do not support a claim that unwarranted shifting of costs is occurring under Oregon's direct access law.

3. Clarifications on Transition Adjustments

PGE's comments discuss the history of the implementation of transition charges in Oregon but overlook some important points. Specifically, PGE provides a partial history of the

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21 ORS 757.600(35).

22 ORS 757.600(31).

development of a 10-year transition charge for PacifiCorp, citing only the Commission's first 2015 order that initially set the 10-year transition charge for PacifiCorp and suggests this 2015 order would justify a 10-year transition charge for PGE.[23] However, the charge approved in the 2015 order cited by PGE was later reversed by the Oregon Court of Appeals. The court found that there was a lack of sufficient evidence to support the full magnitude of PacifiCorp's 10-year charge, which unjustifiably escalated fixed generation costs assigned to the direct access customers for 10 years after those customers committed to stop using PacifiCorp generation.[24] On remand, the magnitude of the 10-year charge was reduced by stipulation of the parties.[25] Additionally, at the time of approval of the 10-year charge in 2015, PacifiCorp's Oregon loads and resource needs were not growing fast enough to offset a significant loss of load to direct access in the near term.[26] In contrast, with implementation of PacifiCorp's new multistate protocol, PacifiCorp may be adding generation resources specific to Oregon loads, and there may be an opportunity to revisit the 10-year charge and the avoided capacity value that direct access customers can bring to PacifiCorp's cost-of-service customers.

Furthermore, PGE's comments overlook that PGE recently proposed a 10-year charge in its last general rate case, UE 335, but the charge was not approved. Due to PGE's resource position and need for resource acquisitions, multiple parties presented credible evidence that a

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[23] *PGE's Op. Comments* at 25 (citing *In the Matter of PacifiCorp, dba Pacific Power: Transition Adjustment, Five-Year Cost of Service Opt-Out,* Docket No. UE 267, Order No. 15-060 (Feb. 24, 2015)).

[24] *Calpine Energy Solutions LLC v. PUC*, 298 Or App 143, 160-61, 445 P3d 308 (2019) (holding, "We conclude that the ultimate finding of the PUC, that it was 'reasonable to assume that fixed generation costs will increase at the rate of inflation after year 5,' is not supported by substantial evidence in the record.").

[25] *In re PacifiCorp dba Pacific Power and Light: 2016 Transition Adjustment Mechanism,* Docket No. UE 296, Order No. 19-406 (Nov. 25, 2019).

[26] *See In the Matter of PacifiCorp, dba Pacific Power: Transition Adjustment, Five-Year Cost of Service Opt-Out,* Docket No. UE 267, Order No. 15-060, at 7 (Feb. 24, 2015) (concluding load growth could not completely offset transition costs)).

properly calculated 10-year charge for PGE would have to include substantial offsetting credits to recognize PGE's avoided capacity costs enabled by a long-term opt out from PGE's cost-of-service portfolio. Thus, PGE agreed in a settlement to withdraw its proposal at least until its next rate case. Notably, in approving the settlement over CUB's objection, the Commission stated "we do not believe the record before us supports a 10-year transition charge."[27] The Commission further "agree[d] with opponents to CUB's position that were we to consider a 10-year transition charge, we would need to review detailed analysis into potential benefits to cost-of-service customers associated with a ten-year opt-out."[28]

Similarly, CUB argues that transition periods have been too short because there has been no load growth since enactment of Senate Bill 1149 to absorb loads lost to direct access.[29] However, the decrease over the relevant time period is not as dramatic as it appears on the graphs supplied in CUB's comments. Instead, analysis of PGE's and PacifiCorp's annual average load since the time when each utility began enrolling significant amounts of load in the direct access programs, in 2004 and 2005 respectively, demonstrates that cost-of-service loads appear to have at least partially offset the lost direct access loads over time.[30] Additionally, the peak loads of PacifiCorp and PGE appear to have increased since Oregon's initial direct access programs were offered,[31] and but for direct access these peaks would have grown larger and necessitated

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27 *In re Portland General Elec. Co., Request for General Rate Revision,* Docket No. UE 335, Order No. 19-129 at 19-20 (April 12, 2019).

28 *Id.*

29 *CUB's Op. Comments* at 6.

30 The data for each utility's sales to retail customers and deliveries to ESS customers is available in the Commission's annually published Oregon Utility Statistics Books.

31 *See* PacifiCorp's 2019 IRP, Vol. II, at Appendix A, p. 12 (displaying annual growth of 0.68% in non-coincident peak Oregon load from 2000 to 2017). Although data for PGE does not appear to be available in its IRPs, PGE's SEC filings show that peak load in 2003 at commencement of the LTDA program was 3,351 MW, and it rose to 3,816 MW by 2018. *See* PGE's 2004 Form 10-K, at 11; PGE's 2018 Form 10-K, at 12, available at https://investors.portlandgeneral.com/financial-information/sec-filings.

additional resource acquisitions. More importantly, both PGE and PacifiCorp are currently forecasting load growth in their IRPs.[32] Thus, load growth and deferred resource acquisitions remain relevant considerations when evaluating appropriate transition charges in Oregon at this time.

4. Response to PGE's and CUB's Comments on the Cost of Legislative Requirements

As noted in opening comments, Calpine Solutions supports direct access policies that require direct access customers to pay for legislative programs in which direct access customers may participate or for which it is fair for direct access customers to share in the costs given the nature of the policy. For some time, parties have asserted that Oregon's direct access programs allow direct access customers to avoid paying for numerous legislative policies and supplemental rate riders associated with those policies. Calpine Solutions has questioned those assertions, given the number of supplemental rate riders that direct access customers do in fact pay. To the extent direct access customers are not paying for certain costs that could be attributed to them, Calpine Solutions remains willing to work with other parties to implement appropriate changes. However, as discussed below, it appears from other parties' comments that the legislatively mandated policies, and the costs thereof, that appear to be avoided by direct access customers are quite limited.

a. Direct Access Customers Already Pay for Most Supplemental Rate Riders

PGE's opening comments contain a long list of supplemental rate riders that direct access customers already pay.[33] These are charges paid even after the end of the five-year transition

[32] *See* PacifiCorp's 2019 IRP, Vol. II, at Appendix A, p.1 (forecasting annual Oregon load growth of 0.87%); PGE's 2019 IRP at p. 102-103, Table 4-6 and 4-7 (forecasting 1.0% annual average load growth as the reference case and 1.2% growth in peak demand).

[33] *PGE's Op. Comments* at pp. 27-28.

period of an LTDA customer. The list provided by PGE includes the following supplemental rates schedules applied to LTDA customers:

- Schedule 105 – Regulatory Adjustments (miscellaneous nonrecurring items such as gains from property transactions);
- Schedule 106 – Multnomah County Business Income Tax Recovery;
- Schedule 108 – Public Purpose Charge;
- Schedule 110 – Energy Efficiency Customer Service;
- Schedule 112 – Customer Engagement Transformation Adjustment (related to PGE's updates of its Customer Information System and Meter Data Management System);
- Schedule 115 – Low-Income Assistance;
- Schedule 126 – Annual Power Cost Variance Mechanism;
- Schedule 131 – Oregon Corporate Activity Tax Recovery;
- Schedule 132 – Federal Tax Reform Credit;
- Schedule 134 – Gresham Retroactive Privilege Tax Payment Adjustment (for customers in the City of Gresham);
- Schedule 142 – Underground Conversion Cost Recovery Adjustment (applicable in certain municipalities);
- Schedule 143 – Spent Fuel Adjustment (Trojan nuclear plant decommissioning costs); and
- Schedule 149 - Environmental Remediation Cost Recovery Adjustment Automatic Adjustment Clause (related to the Portland Harbor Superfund site and others).

Likewise, it appears that direct access customers also pay almost all of PacifiCorp's supplemental rate riders. The following supplemental rate schedules appear to apply in some way to LTDA customers:[34]

- Schedule 80 - Generation Investment Adjustment (related to Lakeside Gas plant generation and interconnection costs);
- Schedule 91 – Low Income Bill Payment Assistance Fund;
- Schedule 93 - Independent Evaluator Cost Adjustment;
- Schedule 95 - Pilot Program Cost Adjustment;
- Schedule 96 - Property Sales Balancing Account Adjustment;
- Schedule 97 - Intervenor Funding Adjustment;
- Schedule 98 - Adjustment Associated with the Pacific Northwest Electric Power Planning and Conservation Act (BPA Columbia River Benefits Credit);
- Schedule 104 – Multnomah Business Tax Adjustment (applicable only to customers located in Multnomah County)
- Schedule 104 - Oregon Corporate Activity Tax Recovery Adjustment;
- Schedule 195 - Federal Tax Act Adjustment (credit for federal tax reduction);
- Schedule 196 - Adjustment to Remove Deer Creek Mine Investment from Rate Base;
- Schedule 199 – Klamath Dam Removal Surcharge;
- Schedule 202 - Renewable Adjustment Clause (Supply Service Adjustment);
- Schedule 203 - Renewable Resource Deferral Adjustment (Supply Service Adjustment);

[34] *See* PacifiCorp Or. Schedule 90 (listing large direct access customers, Schedule 748, as being subject to the same supplemental schedules as corresponding cost-of-service customers, Schedule 48); PacifiCorp provides pricing for these schedules on its price summary on its website, available at: https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/Oregon_Direct_Access_Price_Summary.pdf.

- Schedule 204 - Oregon Solar Incentive Program Deferral (Supply Service Adjustment);
- Schedule 207 - Community Solar Start-Up Cost Recovery Adjustment;
- Schedule 290 - Public Purpose Charge; and
- Schedule 299 - Rate Mitigation Adjustment.

Therefore, it appears that PacifiCorp's LTDA customers already pay virtually all of PacifiCorp's supplemental rate schedules, even though some of these listed generation-related charges should arguably not apply to a long-term direct access customer who has paid the 10-year stranded cost charges.

b. CUB and PGE Identify Only a Limited Number Legislatively Mandated Solar Programs

CUB and PGE identify PGE's volumetric solar incentive program (Schedule 137) and the community solar program start-up costs (Schedule 136) as legislatively mandated supplemental charges avoided by LTDA customers.[35] Notably, PGE acknowledges that LTDA pay their share of above-market costs of the volumetric solar incentive program during the five-year transition period, and it is only the ongoing costs *after* those five years that are at issue.[36] Additionally, as the list above demonstrates, PacifiCorp's LTDA customers appear to be required to pay for the costs of the volumetric solar incentive program and community solar start-up costs, and the current arrangement in PGE's tariffs is apparently due to the manner in which PGE proposed the tariffs.

CUB and PGE also identify net metering as a program that direct access customers avoid funding,[37] but it is not clear how this could be a complaint specific to direct access customers as

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35 *PGE's Op. Comments* at pp. 23, 27-28, 31; *CUB's Op. Comments* at p. 7.
36 *PGE's Op. Comments* at pp. 24.
37 *PGE's Op. Comments* at p. 31; *CUB's Op. Comments* at p. 7.

opposed to a generalized concern that non-residential customers do not pay enough to subsidize residential net metering. Normally, to the extent that a net metering customer is subsidized, those subsidies would be shifted within the net metering customer's rate class, and not from the residential customers to the non-residential customer classes.

Importantly, CUB acknowledges that these solar-related charges avoided by direct access customers are "small due to the relative size of these programs."[38] Although it does not appear to be a major problem, Calpine Solutions remains willing to discuss these issues with other parties.

c. Direct Access Customers Already Make Reasonable Payments for Demand Side Management

PGE also argues that LTDA customers are exempted from certain demand response payments in Schedule 135,[39] and likewise CUB argues that direct access customers do not pay a fair share for demand-side management. Both arguments are misplaced.

With respect to PGE's argument, there is no basis for PGE to charge direct access customers for the programs at issue in PGE's Schedule 135 because the direct access customers cannot participate in the demand response programs. As previously noted, other states have designed demand response programs that allow for the participation of direct access customers. To the extent PGE is willing to allow direct access customers to participate in demand response programs that are additive to the Energy Trust programs, Calpine Solutions would be interested in discussing that possibility.

CUB's argument, in contrast, is made in the wrong proceeding because it is not specific to direct access. Instead, CUB is concerned that *all* customers over 1 aMW are exempt from

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38 *CUB's Op. Comments* at p. 7.
39 *PGE's Op. Comments* at p. 26.

certain incremental energy efficiency funding for the Energy Trust.[40] To be clear, direct access customers pay the same public purpose charge as similarly situated non-residential cost-of-service customers. CUB's concern with an exemption for customers larger than 1 aMW applies equally to cost-of-service and direct access customers over that size threshold. CUB's issue is therefore a generalized dispute between residential and non-residential customers and thus beyond the scope of this proceeding focused on direct access policy.

d. PGE and CUB Provide an Incomplete Picture of Qualifying Facility Costs

PGE and CUB also point to costs of qualifying facilities ("QF") under the Public Utility Regulatory Policies Act of 1978 ("PURPA") as a cost direct access customers avoid,[41] but their arguments overstate their case. First, CUB appears to take the position that the avoided cost rates are always in excess of the utility's actual avoided costs of generation. But there is no record supporting such a finding, and QFs regularly dispute such assertions. Additionally, to the extent a utility's aggregate contracted prices paid to QFs are forecasted to exceed the value of the freed-up power on the wholesale market during an LTDA customer's five-year or 10-year transition period, the difference would be charged to the LTDA customers in transition adjustments during their transition period.

It is also important to note that in many cases direct access customers committed to direct access before major PURPA expense was incurred. In the case of PGE, the majority of PGE's LTDA load opted out of cost-of-service before PGE incurred a significant PURPA obligation, and therefore that load was not load planned for by PGE at the time it entered into much of its existing PURPA contracts. From available sources, it appears that the majority of direct access

40 *CUB's Op. Comments* at pp. 8.
41 *PGE's Op. Comments* at pp. 31-32; *CUB's Op. Comments* at p. 8.

customers on PGE's system opted out of cost-of-service rates prior to 2015.[42] But, according to PGE's PURPA filings, PGE had very limited PURPA activity before 2015, and it is only beginning in 2016 that PGE began to acquire a substantial PURPA obligation.[43] According to PGE's 2019 IRP, PGE currently has 601 MW of cumulative nameplate capacity (estimated at 162 aMW) under PURPA contracts that would be operational by 2021.[44] With respect to LTDA customers that opted out of PGE's service prior to the time that PGE incurred substantial PURPA obligations, it would be unreasonable to assign the new PURPA expense to such customers. The same is true of NLDA customers who were never included in PGE's resource plans used to set the avoided cost rates in these PURPA contracts.

As noted in opening comments, the California Public Utilities Commission assigns direct access customers a power cost indifference adjustment ("PCIA") that includes above-market costs for the full term of contractual obligations entered into at the time of the customer's opt-out election. But even with that type of PCIA framework there is an offsetting stranded benefit compensation, which includes not only the market value of the energy, but also the value of freed-up renewable energy certificates ("RECs"), and a proportional amount of the resource adequacy value of the utility-owned generation, power purchase agreements, and PURPA contracts. In contrast, at present, Oregon's direct access customers still paying transition

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[42] *See* 2018 Oregon Utility Statistics Book, at p. 6, available at https://www.oregon.gov/puc/forms/Forms%20and%20Reports/2018-Oregon-Utility-Statistics-Book.pdf (10-year data table for PGE); *see also* PGE's 2016 IRP at p. 108, Figure 4-6 (showing the growth in direct access programs up to 2015).

[43] UM 1854 PGE/100, Sims-Macfarlane/ 7 (June 29, 2017); *see also* UM 1854 PGE/101 (containing a table with execution date of PPAs as of 2018).

[44] PGE's 2019 IRP at pp. 281-82; *see also* Docket No. RE 143 (containing executed PPAs for PGE's QFs).

adjustments are only transferred the RECs needed to meet their RPS obligation, not any RECs generated in excess of that amount by the utility's stranded renewable assets.[45]

Thus, even if the OPUC were to move to CPUC-style PCIA charge to capture the entire 15-year fixed-price term of PURPA contracts, most PGE LTDA customers opted out *before* PGE incurred major PURPA expense, and those customers to whom such a charge could apply would be entitled to additional stranded benefits under such a charge.

e. Direct Access Customers Do Not Avoid the Costs of RPS Compliance

CUB suggests that ESSs may uniquely avoid RPS costs by using unbundled QF RECs to meet the RPS's requirement for use of 80 percent bundled RECs,[46] but this suggestion is incorrect. Oregon's RPS allows any electric company or any ESS to use unbundled RECs from QFs located in Oregon to satisfy the bundled REC requirement.[47] While CUB characterizes this aspect of the RPS as a "big loophole" for ESSs, it is a part of the law that is equally available to both ESSs and the investor-owned utilities. Presumably, the legislature included this option to provide additional economic incentives to renewable QF generation in Oregon. If it is cheaper to acquire unbundled Oregon QF RECs than to acquire new long-term renewable plants, then the investor-owned utilities have an equal opportunity to do so. Furthermore, when direct access customers choose to do so, direct access provides a mechanism to go far beyond the requirements of the RPS with a source-to-sink, bundled renewable product not available without direct access.[48]

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45 *In re Portland General Elec. Co., Request for General Rate Revision*, Docket No. UE 335, Order No. 19-129 at App. B, ¶ 5; *In re PacifiCorp, dba Pacific Power, 2019 Transition Adjustment Mechanism*, Docket No. UE 339, Order No. 18-421, at 7 (Oct. 26, 2018).
46 *CUB Comments* at p. 6.
47 ORS 469A.145(3).
48 *See Calpine Solutions' Op. Comments* at p. 4.

PGE and CUB also appear to assert that direct access customers avoid costs of above-market long-term renewable assets acquired for RPS compliance.[49] But this argument contradicts the utilities' justifications for recent major renewable acquisitions. PGE's 2019 IRP argues for renewable acquisition several years in advance of RPS need on the basis that a renewable plant is currently a low-cost resource.[50] PGE's IRP asserts: "a wind addition of 150 MWa that comes online by December 31, 2022 to qualify for 60% of the federal production tax credit (PTC) saves approximately $180 million relative to a strategy of relying on wholesale markets for energy and a simple-cycle combustion turbine (SCCT) for an equivalent amount of capacity in the Reference Case."[51] PacifiCorp has recently taken the same type of resource actions and has plans to do so again.[52] Calpine Solutions takes no position on the utilities' decisions to acquire renewable resources. But it is unreasonable to simultaneously argue these renewable resources are the low-cost option while also asserting the acquisition harms cost-of-service customers if direct access customers avoid paying for the "above-market" costs that do not exist.

f. Response to CUB's Argument Regarding Accelerated Depreciation Costs for Coal Plants

CUB also asserts that direct access customers are unjustifiably avoiding the costs of accelerated depreciation of coal plants occasioned by Senate Bill 1547's mandate that coal plants be removed from rates by 2030.[53] From CUB's limited discussion on this point and a review of

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49 *See PGE's Op. Comments* at p. 25; *CUB's Op. Comments* at 6-7.

50 PGE's 2019 IRP, at pp. 33-34.

51 *Id.* at p. 216.

52 *See, e.g., In re PacifiCorp dba Pacific Power, 2017 Integrated Resource Plan,* Docket No. LC 67, Order No. 18-138, at 7 (April 27, 2018) (discussing PacifiCorp's proposal to acquire 1,100 MW of wind resources: "PacifiCorp identifies Energy Vision 2020 as the least-cost, least-risk option to meet near term need within the two- to four-year period that otherwise would be filled by uncommitted [front office transactions], and to meet a long-term energy and capacity need.").

53 *CUB's Op. Comments* at p. 7.

available evidence, it is not entirely clear that direct access customers currently avoid *all* accelerated depreciation costs for coal plants.

To the extent that PacifiCorp's coal plants may have accelerated depreciation, those accelerated depreciation costs would presumably be captured in PacifiCorp's 10-year transition adjustment charge, which includes rates in effect at the time of the opt-out election. As noted above, it appears that direct access customers do in fact pay certain supplemental rate schedules for early retirement costs of PacifiCorp's generation plants, such as the Klamath Dam Removal Surcharge.

With respect to PGE's coal plants, PGE's rate schedule for accelerated depreciation of Colstrip (Schedule 146) may have worked to exempt LTDA customers from the incremental effects of accelerated depreciation and decommissioning costs when initially approved in 2016 as a result of Senate Bill 1547.[54] However, effective January 1, 2018, those incremental costs were placed in base rates with a new depreciation study and are therefore presumably included in the transition adjustment rates paid by LTDA customers opting out since 2018.[55] PGE's Schedule 145 for recovery of Boardman's incremental accelerated depreciation costs appears to have exempted LTDA customers since first adopted in 2010,[56] but PGE states that it includes the cost of this supplemental rate rider in the transition adjustment charges applicable during an

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54 *See In re Portland General Elec. Co., Establishes Schedule 146 Colstrip Power Plant Operating Life Adjustment to Implement into Rates*, Docket No. UE 317, Order No. 16-468 (Dec. 7, 2016); *but see PGE's Op. Comments* at 24 (explaining PGE includes certain supplemental rate schedules in the transition adjustments).

55 *See In re Portland General Elec. Co., 2015 Detailed Depreciation Study of Electric Utility Properties*, Docket No. UM 1809, Order No. 17-365, at 5-6 (Sept. 26, 2017) ; *see also* Advice No. 17-34 (compliance filing of revised Schedule 146 with rates set at zero); *PGE's Op. Comments* at p. 24 & n. 60.

56 *See In re Portland General Elec. Co., Request for a General Rate Revision*, Docket No. UE 215, Order No. 10-478, at 4 (Dec. 17, 2010) (adopting stipulation to implement PGE's proposed Schedule 145); UE 215 PGE/1500, Kuns-Cody/34 (proposing that LTDA customers be exempt from Schedule 145).

LTDA customer's five-year transition period.[57] Notably, in the cases of both Colstrip and Boardman, PGE proposed to treat the direct access loads in the manner they were treated, and it does not appear to have been the result of any arguments by ESSs.

While certain coal retirement costs may in some cases be properly included in a stranded cost charges for direct access customers, it is important to ensure that the costs are not assigned to customers who relied on a different treatment at the time of their opt-out election or who otherwise should not be charged for such costs. However, Calpine Solutions agrees this is an issue that could be investigated further in this proceeding.

5. PGE's Misstates the Policies of Some Other States

PGE's comments contain extensive commentary on policies in other states, but in at least one case PGE incorrectly summarizes those policies. Specifically, PGE discusses Arizona Public Service's ("APS") AG-X program, which is a wholesale buy-through program where an energy service supplier delivers power to APS's system for APS to then take title and deliver the power onto the end-use customer. The program has been fully subscribed since initially offered in 2017. PGE incorrectly suggests the program has caused problems in Arizona and asserts that "Arizona regulators have resisted increasing the original AG-X program cap of 200 MW."[58]

Contrary to PGE's assertions, the Arizona Corporation Commission ("ACC") has not found the AG-X program to be problematic and indeed recently ordered that the wholesale buy-through concept be expanded and made available to additional customers. The ACC recently issued a policy statement directing APS "to either expand and modify its current AG-X to allow medium size commercial customers to participate or propose a new AG-Y alternative generation/buy-through program that would be for medium size commercial customers in its next

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57 *PGE's Op. Comments* at 24.
58 *PGE's Op. Comments* at 41.

rate case."[59] The ACC's policy statement also directed the state's two other investor-owned utilities to adopt a similar buy-through program to APS's AG-X program.[60] While proceedings in Arizona are ongoing to determine the final program parameters of the utilities' AG-Y programs, the ACC's policy statement makes clear that the ACC found value in the possibility of expanding retail choice options for Arizona businesses.

CONCLUSION

Calpine Solutions appreciates the opportunity to submit its comments on the issues under consideration in this proceeding and looks forward to further engagement with other parties and the Commissioners.

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59 *Arizona Corp. Comm'n Policy Statement Regarding AG-Y Alternative Generation Buy-Through Program*, ACC Decision No. 77043, at p. 3 (Jan. 16, 2019).
60 *Id.*