ORDER NO. 26-153

ENTERED 05/07/2026

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.	ORDER

DISPOSITION: DIRECT ACCESS PROGRAM REVISED; COMPLIANCE FILINGS ORDERED

I. INTRODUCTION

In this order, we address numerous issues related to the design of our direct access programs. The Legislature directed the Commission to design direct access to allow competition with the regulated utility, but to keep that competition within delineated bounds. Particularly crucial is the requirement to avoid cross-subsidization between those customers who take service from the utility and those who take service from a competitor, and our decision below is intended to prevent that cross-subsidization, as the statute requires.

II. BACKGROUND

The Oregon Legislature adopted direct access (DA) in Senate Bill (SB) 1149 (1999). Under DA, all nonresidential consumers have the option to purchase electricity from a certified electricity service supplier (ESS) at a market-based rate as an alternative to cost-based service provided through an incumbent utility. Two types of permanent opt-out DA programs are offered to non-residential customers: the New Load Direct Access Program (NLDA) is available to customers with loads not previously served by the incumbent utility and Long-Term Direct Access (LTDA) is available to customers with loads previously served by the incumbent utility.

In 2019, following a stipulation in Portland General Electric Company's rate case in which parties agreed to review and investigate DA issues, the Alliance of Western

Energy Consumers (AWEC) petitioned the Commission to investigate LTDA programs. AWEC cited a need to reevaluate DA in Oregon given the changing energy landscape, PGE nearing its LTDA participation cap, and the fact that PacifiCorp's, dba Pacific Power's, program had been unable to attract many customers. The Commission opened docket UM 2024 as an investigation into LTDA. In PGE's 2019 Integrated Resource Plan (IRP), docket LC 73, the Commission directed questions about whether investor-owned utilities should plan to meet the resource adequacy (RA) needs of LTDA customers to docket UM 2024.

After multiple rounds of comments and straw proposals in docket UM 2024, the docket was re-scoped to incorporate a rulemaking, conducted in docket AR 651, to address a subset of DA issues prior to a contested case in this docket. The rulemaking concluded in 2023, and we adopted rules primarily focused on preferential curtailment, ESS emissions planning reports, and considerations for non-bypassable charges. Following the rulemaking, Staff and intervenors returned to docket UM 2024 to begin the contested case portion of the investigation.

In this proceeding, numerous parties intervened and filed testimony. AWEC, Calpine Solutions, LLC (Calpine), the Oregon Citizens' Utility Board (CUB), the Northwest and Intermountain Power Producers Coalition (NIPPC), NewSun Energy LLC, PacifiCorp, PGE, and Staff of the Oregon Public Utility Commission filed opening and closing briefs.

III. LEGAL BACKGROUND

SB 1149 was passed in 1999, as part of an effort at electric industry deregulation. The bill was explicit that "all Oregon retail electricity consumers should be provided fair, non-discriminatory access to competitive electricity options" and 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." In support of those aims, the bill offered all non-residential consumers the option to purchase electricity from a certified ESS at a market-based rate as an alternative to cost-based service provided through an incumbent utility.[1]

In making direct access available to non-residential customers, the legislature put some strictures on that availability: most relevant here, under ORS 757.607(1), "[t]he provision of direct access to some retail electricity consumers must not cause the unwarranted shifting of costs to other retail electricity consumers of the electric company."

[1] SB 1149 (1999), codified as ORS 757.600 - 757.687.

The legislation also allowed direct access programs to "include transition charges or transition credits that reasonably balance the interests of retail electricity consumers and utility investors."[2]

To implement this statute, the Commission has adopted rules regulating direct access in Division 38 of the Commission's rules. These include rules on non-bypassability, stating that the following factors will be considered in evaluating whether a charge is bypassable:

> (a) whether it is required by statute:
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> (b) whether it is an uneconomic cost of implementing a public policy goal such as those identified in ORS 469A.465 or similar public policy goals related to reliability, equity, decarbonization, resiliency or other public interest for which retail consumers served by electricity service suppliers otherwise would not meaningfully contribute:
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> (c) whether or not it confers a demonstrable electric system benefit on some customers over others:
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> (d) whether it is in the public interest:
>
> (e) whether it is necessary to be non-bypassable under the Commission's discretion in order to establish fair. just, and reasonable rates and prevent unwarranted cost shifting.[3]

The rules also address transition costs and credits, stating, among other things, that "[a]t least once each year, electric companies must offer customers a multi-year direct access program with an associated fixed transition adjustment."[4]

IV. PARTY PROPOSALS

Because several parties to this proceeding have crafted comprehensive proposals in this docket, we here summarize those proposals ahead of taking the issues on an individual basis. We do not include every party's proposal; other parties have adopted elements of these proposals in various combinations. But we have attempted to summarize the most comprehensive proposals made by parties.

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[2] ORS 757.607(2).
[3] OAR 860-038-0170(1).
[4] OAR 860-038-0275(5).

A. Staff

Staff recommends that all parties be charged transition adjustments that are updated annually. The length of those transition adjustments would be the time it takes for load growth to replace the departing load or 20 years, whichever is sooner. In setting transition charges this way, Staff would eliminate PacifiCorp's consumer opt-out charge.

Staff would maintain the caps on DA participation but would create a waiver process where preferentially curtailable customers would be permitted to take service beyond the cap if their ESS has demonstrated compliance with binding state or regional resource adequacy requirements and the ESS participates as a resource in a real-time market available in Oregon. Non-curtailable customers would be permitted to take service above the cap if (1) the customer has backup generation to match their peak demand, (2) their ESS participates in a real-time market available in Oregon, (3) their ESS participates in a day-ahead market in Oregon, (4) their ESS participates in the Western Resource Adequacy Program (WRAP) or qualifying resource adequacy program and can access capacity sharing features, and (5) the customer plans to invest in system modernization improvements that advance state policy or provide near-term environment or economic improvements.

Staff would charge customers on default service 125 percent of either Mid-Columbia (Mid-C) or Western Energy Imbalance Market (EIM) actual prices, plus a demand charge. But customers who have given notice to return to cost-of-service (COS) would only pay 100 percent of either Mid-C or EIM prices plus the demand charge.

B. AWEC

AWEC proposes two options for transition adjustments. First, DA load could transition anytime and pay transition adjustments based on an avoided cost schedule developed in conjunction with the utility's IRP. Customers would pay or receive transition adjustments based on this schedule for 20 years. It would be fixed at the time of transition. Second, DA load would be able to transition by bidding into a request for proposals (RFPs) for new resources, or when a utility requests a waiver of the competitive bidding guidelines. In those cases, DA load could then opt in to DA service based on the avoided cost calculated by the shortlist.

AWEC would have the utilities assess a Provider of Last Resort (POLR) charge, which would be meant to reflect the incremental cost of serving as the provider of last resort. The POLR charge would be waived for customers who agree to be preferentially curtailable.

For curtailable load, there would be a cap for non-RFP DA based on forecasted resource need up to the fifth planning year in the RFP. For RFP load, the cap would be at the level of the resource need. For non-curtailable load, a cap is established at the larger of the prior year's cap or 14 percent of the weather-normalized energy sales in the prior year.

C. NIPPC

NIPPC would have transition adjustments fixed and for a five-year period; it would eliminate the consumer opt-out charge. NLDA customers would be exempt from transition adjustment charges.

NIPPC recommends eliminating program caps entirely. In the alternative, it recommends a phased approach to eliminating caps, under which the Commission would adopt an initial increase of 50 percent above the current LTDA cap, followed by an additional incremental 10 percent on an annual basis.

NIPPC would also have DA customers pay a capacity backstop charge to mitigate cost shifting concerns stemming from utilities' resource adequacy obligations, but also to ensure DA customers can access capacity in a scarce market while compensating the utility for providing that capacity.

NIPPC would set the default supply market rate at the actual cost of power on the market.

D. PacifiCorp

PacifiCorp would largely leave transition adjustments as they are now, however it would recalculate them annually. If the Commission chooses not to update them annually, PacifiCorp would adopt a floor and ceiling on transition adjustments to avoid market error above a certain amount. It would set the length of transition adjustments at four years, but have DA customers pay for years five through ten through the consumer opt-out charge.

PacifiCorp would retain the DA caps, imposing caps on both curtailable and non-curtailable load, and would make the caps non-waivable.

PacifiCorp proposes an energy charge for both preferentially curtailable and non-curtailable consumers who are served with uncommitted supply that would equal the greater of market rates or PacifiCorp's net power costs.

E. PGE

PGE seeks to adopt a charge equivalent to PacifiCorp's consumer opt-out charge. It would adopt a zero-dollar floor on transition adjustments and update the transition adjustments annually.

PGE would also maintain the caps until RA requirements are binding and enforceable. It opposes Staff's waiver proposal.

PGE would set the default supply energy rate at 150 percent of the higher on-peak or off-peak market energy prices using the Mid-C index, EIM, or another relevant index.

V. DISCUSSION

A. Transition Adjustments

Transition charges and credits are both defined by statute. A transition charge is "a charge or fee that recovers all or a portion of an uneconomic utility investment."[5] A transmission credit is "a credit that returns to consumers all or a portion of the benefits from an economic utility investment."[6] To effectuate this statute, the Commission adopted OAR 860-038-0160, which states:

> each Oregon retail electricity consumer of an electric company will receive a transition credit or pay a transition charge equal to 100 percent of the net value of the Oregon share of all economic utility investments and all uneconomic utility investments of the electric company as determined pursuant to an auction, an administrative valuation, or an ongoing valuation.[7]

Currently, Oregon uses an ongoing valuation approach to value transition credits. That means "the process of determining transition costs or benefits for a generation asset [is accomplished] by comparing the value of the asset output at projected market prices for a

[5] ORS 757.600(31).
[6] ORS 757.600(32).
[7] OAR 860-038-0160(1).

defined period to an estimate of the revenue requirement of the asset for the same time period."[8]

1. Should any customers be exempt from transition adjustments? (Issue 1a)

a. Positions of the Parties

NIPPC argues that NLDA customers should not be required to pay transition adjustments because utilities generally have not undertaken costs for the purpose of serving these customers. In other words, it argues, there is no "transition" to "adjust" for.

Staff disagrees, stating that due to the planning horizons that inform utility IRPs and RFPs, a two-year, or even five-year, notice of transition to DA service is not in line with the planning timeframes used for large scale resource investment.

Calpine and PacifiCorp argue that NLDA customers should continue to pay the limited transition adjustment rate set in the Commission's administrative rules as opposed to the transition adjustments applicable to other program customers. Namely, they should continue to pay 20 percent of the utility's fixed generation costs instead of a transition adjustment calculated through the ongoing valuation method.

CUB argues that some large data centers—perhaps loads over 200 MW—should be exempt from transition charges in some circumstances and perhaps even prohibited from subscribing to COS rates.

b. Resolution

We decline to exempt any customer from transition charges. We find that the timeline for notice of transition to DA service is shorter than the planning horizon required for large-scale resource investment, which can be as much as 20 years.[9] Incumbent utilities will have reasonably engaged in preparation to serve anticipated new loads, including preparations to meet state policy requirements such as HB 2021 and the small scale renewable capacity requirements. Accordingly, we find that waiving transition charges for new loads could create significant risk of cost shifting to COS customers. For the same reason, we decline to adopt CUB's position that very large loads should be exempt from transition charges. Calpine and PacifiCorp argue that NLDA customers should continue to pay the rate set out in the Commission's administrative rules, and we concur

[8] OAR 860-038-0005(18).
[9] Staff/ 200, Bolton/12.

that the rate of 20 percent of fixed generation costs for five years is appropriate to prevent cost shifting to COS customers and do not intend to change our rules at this time[10].

2. *How should transition adjustments be calculated and over what term? (Issues 1a-1e, 1g, 1h)*

a. *Positions of the Parties*

Staff would retain the ongoing valuation method for transition adjustments but would adopt a new policy under which transition adjustments would end when load growth has replaced the original level of DA departing load associated with the departing customer, or alternatively, after 20 years—whichever is shorter. Staff also recommends that the transition adjustments be updated annually with fresh inputs during the transition adjustment period. Staff states that because the balance of revenue requirement not recovered through transition charges and credits is paid by COS customers, significant deviations between forecasted and actual market conditions have led to significant losses to COS customers. Accordingly, Staff argues, in adopting annual adjustments, the Commission would appropriately balance the interests of DA customers and the utility, ensuring minimizing the shifting of costs to either DA or COS customers.

PacifiCorp agrees with Staff that the transition adjustments should be recalculated annually, stating that due to numerous factors, forecasts become stale faster, leading to variation between the adjustments fixed at the onset of the election period and the actual shifting of costs. PGE also agrees, stating that under current practices, DA customers can deliberately time their election, which locks them into their transition adjustment charge for the full five years.

Generally, PGE states that it agrees with many elements of Staff's proposal, namely that the current 5-year term is insufficient to collect the revenue to recover utility investments, and it specifies in addition that a floor should be set at zero. PGE states that in addition to Staff's proposal, there should be a minimum term on the transition adjustment charge; PGE would set a minimum term of at least four years. Second, PGE notes that Staff's proposal does not describe how load growth would be determined; PGE would calculate the level of retail energy sales for a given year at the time of the DA enrollment window by using the utility's normalized Oregon MWh retail energy sales for the prior twelve months available at the time.

[10] OAR 860-038-0740(3)(a).

PacifiCorp proposes to shorten the permanent opt-out transition adjustment to four years, but would retain the consumer opt-out charge account for fixed costs in years five through ten to be charged over that four-year period.

NIPPC argues that the transition adjustment should be fixed over the transition adjustment term as, it says, is currently required by Commission rule. It argues that a variable transition adjustment would create market uncertainty, effectively rendering the program unavailable for many customers. Calpine agrees; it argues that the structure of the existing rate calculation enables the utility to avoid cost shifts associated with forecast errors. In short, it says, so long as the market price forecast for the transition term (*e.g.*, one, three, or five years) reasonably reflects market conditions when it is used to set the fixed transition rates at the time of the customer's opt out, the utility can promptly sell the freed-up energy at those market prices to avoid the risk of future price changes. Calpine also states that the uncertainty that would be created by Staff's proposal to update the magnitude of the charge in each year would be problematic.

Calpine further states that the record does not justify departure from the Commission's current practice of using a fixed transition adjustment term. It argues that there is no evidence that the current transition adjustment mechanism has resulted in cost shifting. It also notes that Staff's proposal was introduced in the last round of testimony and remains untested. Calpine states that Staff's proposal would require significant refinement to be workable, including a rulemaking to amend the Commission's administrative rules guaranteeing a fixed transition adjustment rate.

PacifiCorp also objects, stating that Staff's proposal adds significant complexity and was proposed too late in the proceeding to allow other parties to respond. It also argues that Staff's assumption that load growth will negate cost shifting is not supported and further that Staff unreasonably assumes that the companies could not have found less expensive means to serve incremental load growth.

CUB argues that it saw value in Staff's initial proposal that transition charges should cover the first 5 years of direct access. CUB would alter that approach as follows:

- For existing customers under 20 MW, CUB would apply 5 years of transition charges.
- For existing customers over 20 MW, CUB recommends 10 years of transition charges, and the transition charges should not be allowed to be negative.

- For new load, CUB asserts that Staff's proposal that 5 years of transition charges makes sense if the load has been planned for in the IRP.

However, CUB is also concerned by data center load that is not planned for in the IRP and would consider special arrangements such as waiving transition charges and even prohibiting data centers over a significant size from taking service through COS rates.

AWEC argues for a transition adjustment based on avoided costs rather than stranded costs. Under its proposal, a customer could elect DA by paying (or receiving a credit for) a transition adjustment that is based on an avoided cost schedule developed in a utility's IRP. Under AWEC's proposal, if generation costs exceed revenues, then COS customers are better off if the customer transitions to DA, and this customer would receive a transition credit. If revenues exceed generation costs, then the opposite is true and the customer would pay a transition charge.

Other parties object to AWEC's construct. Staff says that at its core, AWEC's proposed transition adjustment methodology is simply calculating the wrong thing. As opposed to calculating amounts required to cover the net costs incurred on behalf of the DA customer as required by OAR 860-038-0160, AWEC proposes to only capture incremental energy savings. Staff also states that a fixed transition adjustment spanning two decades creates significant risk of price staleness.

Calpine states that AWEC's proposal has some conceptual appeal, but that it supports the relative simplicity and predictability of a five-year transition period utilizing the ongoing valuation methodology. PacifiCorp has a number of objections to AWEC's proposal, including that AWEC equates departing load to generation from a new source, which PacifiCorp states is incorrect because unlike new generation, DA customers consume power and may return to utility supply when market conditions become unfavorable. Second, PacifiCorp says, AWEC's proposals would create significant risk of cost shifting because IRP- and RFP-based modeling is inherently uncertain and highly sensitive to input assumptions. Third, PacifiCorp argues, AWEC's proposals would be burdensome to implement by requiring utilities to run multiple avoided cost scenarios for each IRP and RFP cycle, including customer-specific load shapes and resource portfolios. Finally, according to PacifiCorp, the length of AWEC's proposed transition adjustment term would create asymmetric forecast risk for COS customers because electing DA consumers—not the utility or its COS customers—would have discretion to choose when to elect and under which forecast.

PGE also opposes AWEC's proposal. It states that avoided costs are forward-looking whereas transition adjustment charges are backward looking—they assist the utility in recovering costs that have already been incurred in order to serve customers. PGE also states that AWEC did not provide any analysis regarding its proposal to use avoided costs to calculate the transition adjustment and that it bears the burden of proof to support its proposed change.

CUB also opposes AWEC's proposal. CUB states that COS customers should not pay for the value of freed-up capacity for 20 years, as this requirement would increase the risk of cost shifting to COS customers rather than mitigating this risk and is thus contrary to HB 3546.

NIPPC argues that at least preferential curtailment customers and likely all DA customers should be eligible for a capacity credit reflecting the value of capacity it freed up by leaving the system. It makes the point that if the utility can curtail a DA customer then it need not serve the curtailed load even as a last resort. NIPPC also argues that all departing loads provide a capacity benefit to the utility.

Staff states that it would be inappropriate for a capacity credit to be included in the transition adjustment because there is no record to support it and because it is inappropriate to provide a credit for freed-up capacity in light of the POLR obligation. It also states that AWEC previously advanced a similar capacity credit in docket UE 335. In rejecting the proposal, the Commission articulated that a capacity credit could only be justified by a showing that customers choosing LTDA in the future do not harm COS customers; Staff states that such a showing has not been made here. PacifiCorp agrees, stating that paying departing DA customers for capacity that may become necessary to serve those customers later would effectively be cost shifting.

Calpine states that if the transition period is limited to five years, a capacity credit is unnecessary but contends that a longer period may necessitate a capacity credit.

b. Resolution

Transition adjustment charges are essential to avoiding unwarranted cost shifting, including the opportunity for DA customers to shed risks COS customers cannot avoid. They also should not be structured as an explicit barrier to pursuing DA. Finally, they must be administratively manageable. To balance these conflicting needs, transition adjustment charges will be charged for five years, updated annually.

We agree with PacifiCorp and Staff that annual updates are appropriate because forecasts are imperfect; we find, as the utilities testify, that deviations between forecasted and actual market conditions have led to losses to COS customers.[11] This problem has been exacerbated in recent years by increased market complexity and volatility making forecasts less accurate than they were at the time the Commission adopted the current policy. We note that COS customers do not experience long-term, locked-in costs, and find that it is appropriate for DA customers to share that risk.

Our rules specify that: "At least once each year, electric companies must offer customers a multi-year direct access program with an associated fixed transition adjustment."[12] We do not find, as some participants urge us to do, that this rule precludes annual updating. We find that the rule requires transition charges to be fixed each year at the time of the election window.

We also find that five years is an appropriate term. We decline to adopt Staff's and AWEC's proposal to set the term of transition charges equivalent to the time it takes load growth to replace departing load. We find that Staff's and AWEC's proposal would add significant complexity and uncertainty to the transition adjustment process. Calpine argues annual updates to the transition charge creates new complexity and uncertainty for DA customers.[13] While, as discussed above, we find that annual updates appropriately match risks between DA and COS customers, extending the complexity of annual updates for an unknown length of time risks creating an insurmountable barrier to DA. Load growth may or may not replace DA load over five years depending on a host of factors, but a fixed transition adjustment term when combined with annual updates to the transition adjustment cost appropriately balances the need to avoid unwarranted cost shifting with the requirement to avoid creating insurmountable barriers to DA.

We decline to adopt a capacity credit. We find that as long as utilities have the POLR obligation and are acting as RA backstop (which we discuss below), it is inappropriate to view capacity as "freed up" by departing load.

3. Should transition adjustments have a floor or ceiling? (Issue 1f)

a. Positions of the Parties

Staff does not recommend establishing a floor or ceiling for transition adjustments. Staff states that it could prevent accurate valuation of the transition adjustment by creating an

[11] PAC/200, Mitchell/17-18, 24-25; PGE/200, Almeida-Ferchland/43-44.
[12] OAR 860-038-0275(5).
[13] Calpine Solutions/200, Higgins/11-12.

artificial mismatch between forecasts and actual prices. Further, Staff notes that while a floor unduly captures benefits in favor of COS customers, a ceiling unduly captures benefits for DA customers. Instead, Staff says, aligning transition adjustments with the actual costs and benefits is the best method to ensure COS customers are indifferent to the DA program. Calpine agrees, stating that the floor and ceiling proposals are arbitrary and violate a fundamental premise of the ongoing valuation method for calculating transition adjustments, namely that transition adjustment calculations in Oregon are to reflect 100 percent of the stranded benefits (*i.e.*, credits) as well as stranded costs (*i.e.*, charges). NIPPC also agrees.

PacifiCorp, on the other hand, recommends a floor and a ceiling if the Commission rejects the annual update proposal. PacifiCorp's proposed ceiling is 150 percent of the company's net power costs. PacifiCorp argues that this would prevent the most egregious incidences of cost shifting, which results under current practice because of a series of errors that are built into the calculation.

PGE, meanwhile, recommends a floor of zero. PGE states that because risks exist that require the utility to incur costs, such as for foregone demand response opportunities, system risks, and reserve procurement, a transition charge for both NLDA and LTDA customers should never be negative.

b. Resolution

We do not adopt a floor or ceiling on transition charges. We find, as Staff argues, that it could prevent accurate valuation of transition adjustments, which would increase the risk of cost shifting to COS customers or of providing an unreasonable disincentive to direct access service. We also find that it would not allow accurate recovery of stranded costs and benefits. Further, because we order annual updates, a floor and ceiling is unnecessary to mitigate the greater forecast errors that can occur when transition adjustment charges are fixed. We disagree with PGE that a floor of zero is necessary to mitigate risks faced by the utility, finding that those risks can be mitigated in other ways, such as the capacity back-stop charge, discussed below.

4. Consumer Opt-Out Charge (Issue 1i)

a. Positions of the Parties

PacifiCorp's consumer opt-out charge is intended to recover fixed generation costs from permanent opt-out participants for years six through ten of DA and is offset by the projected value of freed-up energy over that same period. It is paid over the five-year

transition adjustment period, and currently only applies to PacifiCorp DA load. PacifiCorp proposes to keep its consumer opt-out charge, and PGE proposes to add an equivalent charge in this proceeding.

Staff recommends eliminating the consumer opt-out charge for PacifiCorp and not allowing PGE to implement one. Staff states that this charge is meant to address stranded asset risks, but the stranded asset risk targeted by the consumer opt-out charge can be more thoroughly addressed in the implementation of House Bill (HB) 3546 (2025) (the POWER Act). It also states that PGE's consumer opt-out charge is not justified by its evidence of cost shifting, discussed below, stating that it could equally lead to a windfall of over-recovery for the utility.

Calpine agrees, stating that PacifiCorp's consumer opt-out charge creates an inherently negative value proposition during the five-year transition period by front loading additional transition charges into those five years. Calpine adds that, to the extent the credit is retained, the Commission should reject PacifiCorp's argument that the charge should include a floor that prevents it from being a credit in times where the calculation results in a credit. NIPPC also agrees, arguing that the consumer opt-out charge has no justification in cost-causation principles and that the utilities have not provided adequate justification for recovering ten years of transition charges in a five-year period.

PacifiCorp defends its consumer opt-out charge, and its proposal that it should not become a credit, stating the consumer opt-out charge mitigates cost shifting by requiring the departing DA customers to pay the portion of fixed generation costs attributable to years six through ten following their election to opt out. PacifiCorp cites the order where the Commission originally approved the charge, where it stated that "the consumer opt-out charge is necessary pursuant to implementation of the state's [DA] laws by our rules" and that "[t]he inclusion of an opt-out charge is consistent with our request that PacifiCorp design a five-year opt-out program that would protect other customers from cost shifting."[14] PacifiCorp also notes that HB 3546 does not address this, because it specifically carves out the right of large customers to seek DA. PacifiCorp also maintains that the charge should not be allowed to become a credit, arguing that the intent underlying the charge is to protect COS customers from taking on a larger share of fixed investments, not to protect DA customers from increases in market prices.

PGE agrees with PacifiCorp and seeks to establish its own charge for years 6-10 of the opt out. It states that the transition adjustment for customers who opted out in 2012 and 2013 and had their transition adjustment period end in 2017 and 2018 respectively, was

[14] *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 6 (Feb. 24, 2015).

not adequate to recover the costs of the departing load. In general, PGE states that it plans for all load on its system, and five years is not sufficient to cover the cost of the generation for departing load.

b. Resolution

We find that PacifiCorp's consumer opt-out charge should be eliminated and do not allow PGE to establish its own equivalent charge. We find that the utilities have not adequately justified ten years of cost recovery of forecasted costs and benefits over a five-year period. COS customers do not similarly pay ten years of forecast costs over five years; thus, the consumer opt-out charge creates a significant imbalance in the management of cost and risk between the two customer types and an unreasonable disincentive to DA. We agree with Calpine that the consumer opt-out charge creates an inherently negative value proposition during the five-year transition period by front-loading ten years of forecast cost and is an unnecessary impediment to participation in PacifiCorp's five-year program.[15] We also find, as Staff argues, that the consumer opt-out charge could lead to a windfall for the utility. As Staff points out, PacifiCorp initially justified the charge by making a showing in 2015 that "$58.9 million on a nominal basis, or $35.4 million on a net present value basis" would be billed to COS customers if not for the consumer opt-out charge.[16] Neither PacifiCorp nor PGE have made a similar showing here. Finally, Staff's proposal above, to update transition charges as load grows to replace the departing DA customers, appears designed to accomplish the goal PacifiCorp purports to be addressing through this charge, without creating the intergenerational equity and forecast error concerns of the consumer opt-out charge. However, we have already determined that Staff's proposal is not administratively feasible and also creates an unnecessary barrier to DA as we seek to balance a workable DA program with avoiding unnecessary cost shifting. We find that annual updates, which limit forecast risk, and no consumer opt-out charge strikes the appropriate balance between DA and COS customers and will minimize the risk of cost shifting.

5. PacifiCorp's Spreadsheet Approach (Issue 1j)

a. Positions of the Parties

PacifiCorp proposes to use a spreadsheet calculation based on a blend of market prices to help value the freed-up energy, instead of relying primarily on model runs to measure transition adjustments. PacifiCorp also proposes to reconcile the variance between forecasted and actual transition costs through the power cost adjustment mechanism.

[15] Calpine Solutions/100, Higgins/8-9; *see also* NIPPC/100, Al-Jabir/15-16.
[16] Docket No. UE 267, Order No. 15-060 at 5.

Staff recommends revising PacifiCorp's approach according to Staff's transition adjustment proposal (*i.e.*, to charge transition adjustments over up to 20 years in accordance with Staff's proposal). Staff understands PacifiCorp's spreadsheet approach to be more closely in line with PGE's current methodology. Calpine agrees, writing that it has long recommended use of forward market prices instead of the power supply models to value freed-up energy for transition adjustments. PacifiCorp also defends its proposal, stating it would reduce complexity and make the calculation more accurate and transparent. PacifiCorp also states that its proposal would eliminate the risk of over- and under-recovery due to a mismatch between what is paid to or received from DA participants and what is included in COS customer rates. NIPPC also supports PacifiCorp's proposal.

b. Resolution

We find that PacifiCorp's spreadsheet approach is reasonable and note that it appears to be uncontested. We approve PacifiCorp's proposal to use this approach going forward.

B. Non-bypassable Costs (Issues 2a-d)

1. Positions of the Parties

Staff recommends that costs should be non-bypassable for some types of DA customers and bypassable for others only to the extent a subset of DA customers experience the correlating system benefits. Staff cites OAR 860-038-0170(1)(c), requiring that the Commission consider whether a charge confers a "demonstrable electric system benefit on some customers over others."

Calpine recommends no changes be made to the Commission's administrative rules, which set forth a framework for assessing non-bypassable charges. Calpine argues that there is no basis in the record for adjustment to the rule in this proceeding.

Staff recommends that charges be grouped by the benefits they provide to DA customers and then separately assessed by the Commission to determine final non-bypassability. Staff states that categorizing charges by their commonalities is valuable for assessing them and would likely help the Commission determine whether a charge is non-bypassable.

Other parties object: Calpine states that the Commission should evaluate each proposal for a non-bypassable charge on its own merit in filings specific to those charges. NIPPC states that the record is insufficient to support a finding on categories of non-bypassable costs in this docket.

PGE states that the Commission should make determinations of non-bypassability on a case-by-case basis but does list several broad categories of costs it believes are non-bypassable: those include net-metering costs, community solar costs, transportation electrification, accelerated depreciation and decommissioning costs of coal plants, and demand response costs.

Staff recommends that the Commission consider bypassability of charges when the utility files a tariff containing the charge. Calpine, PGE and PacifiCorp take substantially similar positions, with PacifiCorp and AWEC also identifying a general rate case as an appropriate time to determine cost bypassability.

Staff does not suggest that the Commission decide on bypassability of specific charges as part of this proceeding; and nor do other intervenors except PGE, which states that the Commission should make a determination on the categories it identifies, while reserving individual cost determinations for other proceedings.

2. Resolution

We do not believe the record justifies decision on specific non-bypassable charges or categories of non-bypassable charges at this time. We will consider non-bypassable charges when they are brought before us in general rate cases or individual tariff proceedings. Nor do we believe the record justifies revising our rules on non-bypassable charges.

We take this opportunity to emphasize the importance of determining non-bypassability when warranted. Direct access should not be an off-ramp to paying for legislatively-determined priorities that, by rights, should be spread to all Oregon customers. Accordingly, as our rules indicate, we will not hesitate to find charges non-bypassable when they are meant to effectuate legislative policies applicable to all customers. We disagree with arguments that would focus the analysis on "benefits" to DA customers; rather, whether a charge is non-bypassable should be based on whether the charge benefits Oregon consumers as a whole. We are also concerned with ensuring COS customers are not exposed to unavoidable costs that DA customers can shed.

C. Election Window (Issue 3a, 3b)

1. Positions of the Parties

Staff recommends the Commission refrain from updating the timing of the annual election window until the effective dates for PAC's Transition Adjustment Mechanism (TAM) and PGE's Annual Update Tariff (AUT) are adjusted to align with the recently enacted prohibition on residential rate increases during winter months, November 1 through March 31. Instead, Staff suggests, the Commission should direct parties to jointly develop a new election window date, in conjunction with developing TAM and AUT schedules, that better aligns with submission dates for RA forward showings.

Staff also opposes PGE's proposal to reduce the election window to one week, stating that there has been no showing of cost shifting to COS customers under the current, month-long window. Calpine agrees, stating that the effect of the proposal would be to arbitrarily restrict the ability of eligible customers to elect DA. NIPPC agrees as well, stating that the Commission has repeatedly treated PGE's September election window as a deliberate, full-month construct. NIPPC also states that a full month can allow customers and ESSs to complete contracting, credit, and internal approval steps in an orderly manner.

PGE defends its proposal, stating that, in the past, the election window was only 3 days each quarter, which was workable for DA participants. PGE also argues that the current window can lead to cost shifting and problematic incentives because a prospective LTDA customer can submit an LTDA contract early in the window and during the rest of the month track the market price.

PacifiCorp recommends moving the start of its month-long DA election window from its current position of opening in November 15 to a date in September. PacifiCorp states that this change would allow ESSs to incorporate new customer load into their forward showing RA compliance filings and provide a series of other benefits. PacifiCorp believes that this is an appropriate docket in which to move forward with this change and supports moving the beginning of the election window to a date in September.

2. Resolution

We decline to limit the election window to one week and determine that it should remain a full month to allow for customers and ESSs to complete contracting, credit, and internal approval steps. We do not find PGE's argument that a month is long enough to allow for gaming of market prices to be persuasive or supported by evidence.

We are persuaded that the election window schedule should be developed in conjunction with AUT and TAM schedules going forward and direct the parties to do that in the docket relating to implementation of HB 3179, docket UM 2405.

D. DA Program Caps and Eligibility

1. Positions of the Parties

PacifiCorp's current permanent opt-out program cap for LTDA customers is 175 aMW; its NLDA program is capped at 89 aMW. PGE caps its LTDA program at 300 aMW and its NLDA program at 119 aMW.

The parties began by discussing whether the caps are justified by a record of cost shifting from DA customers to COS customers. Staff views the record as supporting a finding that the current DA programs could cause unwarranted cost shifting if the transition adjustment methodology is not revised or if caps are eliminated.

Calpine argues that the record does not support a finding that the DA programs cause unwarranted cost shifting, and instead, it says, assertions of cost shifting rely on hypothetical scenarios that have not been demonstrated to bear a resemblance to real world or historical events. Calpine also argues that the cost shifting concern raised by PGE was primarily about ESS scheduling practices, a FERC-jurisdictional matter that it asserts has now been resolved by FERC through approval of PGE's proposed resource sufficiency evaluation charge (RSE) applicable to all ESSs as part of PGE's new Extended Day-Ahead Market (EDAM) tariff. NIPPC agrees, arguing that PGE's and PacifiCorp's testimony include no concrete evidence of cost shifting, only hypothetical or theoretical scenarios that do not reflect actual, documented cost shifts.

PacifiCorp, on the other hand, argues that it has provided extensive evidence of cost shifting. In particular, PacifiCorp states that it provided historical evidence of cost shifting over time using data inclusive of market volatility, inaccurate forecasts, and non-perfect operations.[17] PacifiCorp also states that it provided evidence that in all but one year since 2016, costs have shifted from DA customers and onto COS customers.[18]

PGE also states that there is a likelihood of unwarranted cost shifting from DA customers if the program caps are increased—it states that cost shifting will occur when PGE does not have reserve to cover demand that ESSs fail to serve. It also argues that there are

[17] PAC/200, Mitchell/13-14.
[18] PAC/200, Mitchell/15.

reliability implications and that there is real risk that the reserves PGE holds for COS customers will not be sufficient to meet both its obligation to serve COS customers and to act as a balancing authority (BA) or POLR for NTDA and LTDA that PGE cannot procure for.

PGE and PacifiCorp argue for maintenance of the caps. PacifiCorp generally proposes to retain the existing caps on DA load, but to change the denomination of the cap from aMW to MW. PacifiCorp proposes that half of the cap for each program be reserved for participants in the preferential curtailment option, and that neither cap should be waivable. PacifiCorp argues that increasing the amount of load and the aggregate size of transition adjustments paid would amplify existing rate impacts on COS customers. Moreover, PacifiCorp states, the company does not plan to serve the loads of participants in the LTDA programs, and therefore the prospect that these loads will return unexpectedly to utility service presents significant operational and cost risks to remaining customers.

PGE also argues that there is a likelihood of unwarranted cost shifting from DA customers if the program caps are increased. PGE asserts that reliability will be compromised if the caps are increased, stating that some ESSs cannot meet their own RA requirements, which is one of many indicators of system reliability. It also presents evidence that ESSs have systematically under-scheduled load, which could lead to reliability problems if the caps were lifted and they continue to under-schedule.

Staff recommends the caps stay in place but proposes a waiver construct which is addressed in subsections (h) and (i), *infra*. CUB agrees with Staff.

Calpine states that the Commission should ensure that the non-curtailable caps are no lower than the current LTDA and NLDA enrollment caps, but does not oppose expansion of the caps beyond the current cap levels.

NIPPC argues that the caps should be lifted, noting that Staff has not provided evidence of current cost shifting that would justify the caps. NIPPC notes that Staff calls the caps a "blunt" tool and argues that substantial evidence in the record does not support continuance of the caps. At the same time, NIPPC argues that there *is* substantial evidence that the caps pose a barrier for DA.

NewSun also argues that the caps should be lifted. NewSun states that there is no evidence of cost shifting occurring, that a utility's POLR obligations are sufficiently protected by the three layers of certification that an ESS must obtain before being allowed to serve load, that there is sufficiently long lead time between the notification of

a DA customer's return and its return, and that RA obligations are sufficient to protect COS customers from subsidizing the provision of grid services to DA customers.

AWEC recommends that the Commission establish different program caps for non-curtailable and curtailable customers. For non-curtailable customers, caps would be set at 14 percent of each utility's weather-normalized sales but with a floor at the utility's existing cap levels. AWEC argues that this level is comparable to the utilities' planning reserve margins. Curtailable load, on the other hand, would not be explicitly capped but, AWEC states, AWEC's transition adjustment methodology, which relies on avoided cost schedules and the utility's resource needs, would naturally limit the amount of curtailable load likely to transition to DA at any given time.[19]

NewSun argues that NLDA customers should be excluded from any caps, writing that this will allow large loads like data centers to procure their own electricity from independent ESSs and reduce the incumbent utilities' burdens to provide power.

NIPPC argues that a phased approach to lifting the caps is appropriate if the Commission chooses not to lift them entirely in this docket. Specifically, NIPPC recommends that if the Commission pursues a phased approach to lifting the cap, it adopt an initial increase of 50 percent above the current LTDA cap, followed by an additional incremental 10 percent on an annual basis until the cap is eliminated.

PacifiCorp opposes a phased approach to lifting the caps, arguing that phasing would not prevent the cost shifting or reliability risks that eliminating the caps creates. PGE agrees, stating that phased lifting of the caps would be arbitrarily based on the passage of time and does not consider actual systems conditions that are occurring during that time. Staff opposes a phased lifting of the caps as well.

PacifiCorp proposes to retain existing cap sizes—denominated in MW instead of aMW—but to reserve half of the applicable cap for each LTDA program for non-curtailable load and half for preferentially curtailable load. PGE also proposes a subset of the caps for potentially curtailable customers; namely of the existing caps, PGE recommends that preferential curtailment customers can be enrolled up to a cap of 60MWa.

Calpine objects, stating that the new preferential curtailment option was adopted as a means to allow expansion of the existing enrollment caps for customers willing to be subjected to curtailment. Accordingly, it says, adoption of a preferential curtailment

[19] *See* AWEC Opening Brief at 14. AWEC states that this is because transition adjustments would be recalculated if enough load takes direct access service to eliminate future resource needs and, therefore, these adjustments would result in significant charges that would discourage additional direct access participation.

option should not cause the permitted level of non-curtailable load to be reduced from currently approved levels.

NIPPC agrees that if there are caps (it proposes eliminating them), there should be a higher cap for curtailable loads enrolled in DA as reliability adequacy concern is mitigated when DA load is curtailable.

NewSun argues that caps should not apply to customers that elect to receive curtailable service, stating that, in the case of curtailable customers, COS ratepayers remain sufficiently protected without a cap because curtailable DA loads, by definition, pose minimal reliability risk to the system.

Staff argues that preferentially curtailable customers should be permitted to take service beyond the cap if their ESS has demonstrated compliance with binding state or regional RA requirements and the ESS participates as a resource in a real-time market available in Oregon.

PacifiCorp argues that caps on DA load should not be waivable. PacifiCorp argues that determination of the appropriate size of its LTDA programs requires an extensive understanding of the company's ability to reliably serve load as the POLR. Accordingly, PacifiCorp states, to plan for its system and keep costs low for all customers, the company requires certainty regarding the amount of returning DA load it could be required to serve. PGE agrees, stating that any waiver mechanism undermines the core purpose of caps: to place firm bounds on risk exposure when future system impacts are uncertain.

PacifiCorp does, however, believe that ESSs should be required to show participation in an organized market and demonstrate compliance with a resource adequacy program before serving DA load.

Staff proposes that non-curtailable load should be permitted to take service above the program cap if it can demonstrate that: (1) the customer has backup generation to match their peak demand, (2) its ESS participates in a real-time market available in Oregon, (3) its ESS participates in a day-ahead market in Oregon, (4) its ESS participates in the WRAP or qualifying RA program and can access capacity sharing features, and (5) the customer plans to invest in system modernization improvements that advance state policy or provide near-term environment or economic improvements.

CUB also advocates for a waiver process, stating that in evaluating a waiver, the Commission should recognize that the risk of costs being shifted to COS customers is greater when existing customers request to leave for DA than it is for NLDA where the utility has not yet invested substantial resources to meet their loads. Accordingly, CUB argues there may be a different waiver process for existing customers than there is for new direct access load. On rebuttal, CUB states that the Commission could consider raising the cap for direct access customers who have resource adequacy plans that do not require funding from the utility or its customers.

NIPPC objects to Staff's waiver criteria, stating that they are not clear, objective, and achievable. In particular, NIPPC argues that the requirement that an ESS be a market participant is impossible to achieve.[20] AWEC agrees and also objects to the requirement that an ESS participate in a binding RA program, writing that it would be manifestly inequitable and unreasonable for the Commission to conclude that an ESS that is not currently subject to binding RA requirements cannot serve load but that the utilities can serve that same load without taking on these same obligations.

NewSun also argues that any waiver process should be clear and that the presumption should be in favor of granting the waiver unless there is a clear showing that it should not be granted.

2. Resolution

We agree with Staff that the caps will remain in place but will be waivable. For preferentially curtailable customers, the cap may be waived if their ESS has demonstrated compliance with binding state or regional resource adequacy requirements and the ESS participates as a resource in a real-time market available in Oregon. For non-curtailable customers, the cap can be waived if the customer can demonstrate that: (1) the customer has backup generation to match their peak demand, (2) its ESS participates in a real-time market available in Oregon, (3) its ESS participates in a day-ahead market in Oregon, (4) its ESS participates in the Western Resource Adequacy Program (WRAP) or qualifying RA program and can access capacity sharing features, and (5) the customer plans to invest in system modernization improvements that advance state policy or provide near-term environment or economic improvements.

A petition for waiver may be brought to us at any time; once granted, the customer may then elect DA service during the next election window. Staff will bring that waiver application to a public meeting within 90 days of its filing.

[20] NIPPC/300, Tilghman/3; PGE/300, Almeida-Ferchland/11.

We understand and accept that it is likely not possible for ESSs to demonstrate their participation in a binding regional RA program at this time but believe that it will be possible in the future, allowing a transition to load using DA above the caps. We expect all parties to engage in regional program design efforts with the goal of maximizing diverse participation so resource adequacy costs and reliability risks can be minimized. Regional RA programs should be used to enable effective and reliable ESS participation in the Oregon marketplace and not to artificially block some participants. At this time, there is space under both caps, so potential DA load will not be precluded from service while the regional RA framework evolves.

Our determination is based on concerns about reliability and cost shifting. It is also based on the principle that utilities and ESSs should be held to similar performance obligations, in this case for RA. In 2019, we found that caps and limits "place bounds on potential negative outcomes particularly where future system impacts for a course of action are unknown."[21] We have also found that we may:

> preserve, adjust, or impose a cap if an increase in DA load will:
>
> - Compromise system reliability
> - Shift an unacceptable amount of cost to cost-of-service customers
> - Pose undesirable long term financial impacts to the electric system or cost-of-service customers
> - Pose other unmitigated risks to cost-of-service customers.[22]

We do not need to find that every one of these factors is present in order to find that a cap is needed; rather, we can balance the circumstances as they exist at the time of our determination.

We find that PGE has demonstrated that ESSs that are not participating in binding RA programs may lead to reliability issues over time. PGE has submitted evidence showing that in the last few years as the Western Interconnection has faced reliability issues, ESSs in PGE's BA have consistently had larger amounts of under scheduled capacity in most every month as compared to prior years.[23] In addition, PGE provided testimony explaining how cost shifting may occur if an ESS is failing to actually deliver the supply

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[21] *In the Matter of Portland General Electric Company, Request for a General Rate Revision*, Docket No. UE 335, Order No. 19-128 at 3 (Apr. 11, 2019).
[22] *In the Matter of Rulemaking Regarding Direct Access Including 2021 HB 2021 Requirements*, Docket No. AR 651, Order 22-364 Appendix A at 9 (Sept. 26, 2022).
[23] PGE/100, Goodspeed-Ferchland/21 (Figure 5 (showing that during the largest under-scheduled hour in January 2024, ESSs actual capacity was 76% less than what was scheduled); PGE/201).

that it has scheduled.[24] PacifiCorp also submitted testimony demonstrating that cost shifting has occurred as a result of the current regime[25] Together, we find this sufficient reason not to remove or raise the caps at this time.

On the other hand, we find that Staff's waiver criteria will provide some flexibility while mitigating the risk of reliability problems and cost shifting. There are different waiver criteria for preferentially curtailable and non-curtailable customers because they represent different kinds of risks to the system. While preferential curtailment remains a last resort, the ability to curtail mitigates some risk and so we find that less stringent waiver conditions are appropriate for those customers.

We reject PacifiCorp's proposal to measure its cap in MW instead of aMW. While we do not object to the concept of a capacity-based cap, this would constitute a de facto lowering of the cap which the record does not support. PacifiCorp may, in a future proceeding, submit evidence on what would constitute a MW cap that is equivalent to its current aMW cap and we will consider it at that time.

E. Switching Between Direct Access Programs (Issue 4j, 6b)

1. Positions of the Parties

In UE 399, the Commission interpreted the language of PacifiCorp's existing tariffs to allow switching from the three-year program to the permanent opt-out program. However, at that time the Commission clarified that decision was based on the language of the tariff itself and noted that PacifiCorp could propose a change to that tariff. PacifiCorp now does so, arguing that permitting participants to switch from one multi-year program to another—or from default service to another DA program—allows DA consumers to arbitrage between forecasts, imposing an asymmetric risk on COS customers.

Staff agrees, arguing that DA customers should remain on the default supply schedule until they have fulfilled the notice of return period, four years for PacifiCorp and three years for PGE. It reasons that the notice period was adopted by the Commission to ensure that the incumbent utility had time to plan for returning load and the record contains no evidence demonstrating that this planning period is no longer necessary.

[24] PGE/201C, Almeida-Ferchland/3-5.
[25] PAC/200, Mitchell/13-14.

Calpine disagrees. Calpine argues that there are legitimate reasons for a customer to switch from one program to another and that barring that election solely to lock the customer into an erroneous PacifiCorp forecast does not serve a useful public purpose.[26] NIPPC agrees, as does AWEC. Both state that the record does not contain substantial evidence to deviate from current practice.

2. Resolution

We find that annually updating transition adjustments should limit the opportunity for arbitrage in switching between DA programs or from default service to another DA program. We also find that there is nothing in the record to support that prohibiting switching is needed to prevent unwarranted cost shifting in an environment with annual updates to transition adjustments. Accordingly, we allow switching at this time. We offer PacifiCorp the opportunity to return to us with additional evidence if problems occur under the annual update framework.

F. Should the aggregation limit for customers eligible to enroll in PacifiCorp's three-year and five-year programs be modified to bring its limit in line with that in PGE's programs? (Issue 4k)

1. Positions of the Parties

PacifiCorp customers must aggregate to at least 2 MW to be eligible to participate in the DA programs, whereas PGE customers must only aggregate to at least 1 aMW.

Calpine argues that PacifiCorp's three-year and five-year programs should be modified to bring its limit in line with that in PGE's programs to remedy what it views as an unreasonable discrepancy. Calpine asserts that there is no record-based justification for PacifiCorp having a higher threshold.

PacifiCorp responds that it prefers to have its aggregation limit in MW rather than aMW, and that this is consistent with its proposal to measure its cap in MW rather than aMW. It states that aMW threshold is more administrable and better reflects the risks posed by DA participation.

[26] Calpine Solutions/200, Higgins/20.

2. Resolution

We do not believe it is necessary for PacifiCorp and PGE to have the same aggregation limit at this time and do not find that the record justifies a departure from current practice.

G. Resource Adequacy

1. Capacity Backstop Charge (Issue 5a, Issue 5b)

a. Positions of the Parties

Calpine, AWEC, and NIPPC argue that the Commission should require the utilities to offer DA customers the option to pay the utility a capacity backstop charge to be included in the utility's RA load. Calpine states that there is strong evidence that it is not commercially feasible for ESSs to procure the required RA capacity and supporting firm transmission from utilities or other market participants at this time for delivery to the BA of Oregon utilities.[27] In particular, Calpine states it has issued requests for offers soliciting resource-adequacy-compliant capacity and supporting firm transmission, but it received no responses to its solicitations.[28] Calpine is concerned that, as a result, there could be an exodus of existing DA customers back to the utility despite their desire to remain in the DA program.

NIPPC is also supportive of the capacity backstop charge. NIPPC witness Al-Jabir testified: "Under this approach, PacifiCorp and PGE could explicitly plan to serve [DA] loads and fully recover the cost of the capacity needed to serve such loads through a backstop charge."[29] This approach, he states, would have the added benefit of "ensur[ing] that lifting the* * *program caps does not impose any cost burden on COS customers, nor would it shift costs from direct access customers to COS customers, as long as the backstop charge fully compensates the utility for the incremental cost of providing this service."[30]

AWEC argues that utilities should be required to offer RA to only non-curtailable customers, but non-curtailable customers should only be required to take this service from the utility if their ESS does not meet applicable RA requirements. AWEC states that this is reasonable because it ensures that the utility is not unnecessarily planning for the

[27] Calpine Solutions/200, Higgins/6-8.
[28] Calpine Solutions/200, Higgins/7-8; Errata Calpine Solutions/202 (solicitation dated November 18, 2024); Calpine Solutions/203 (solicitation dated March 4, 2025).
[29] NIPPC/400, Al-Jabir/17.
[30] *Id.*

non-curtailable customer. Curtailable customers, it states, inherently supply their own RA by being curtailable.

PGE agrees that the Commission should allow an ESS to pay PGE for capacity planning in order to comply with state RA requirements. However, PGE states that it is premature for the Commission to determine how the costs of the RA product should be calculated without the requisite record evidence. PGE's conclusion is that the circumstances merit Commission approval of the development of an RA product, but the record is insufficient to determine the exact details of that product. It also states that it would take some time to develop. Finally, PGE argues that the capacity backstop charge as proposed is not a full RA product, but rather a capacity product; it states that RA includes transmission, among other things. Therefore, PGE argues that the Commission should not find that paying a capacity backstop charge is equivalent to full RA compliance.

PacifiCorp strongly opposes planning for RA for ESSs. PacifiCorp states that requiring the company to backstop departed LTDA program load would shift the burden of capacity planning back to the company, forcing COS customers to bear the cost and risks necessary to allow DA consumers to safely access the wholesale market. PacifiCorp also argues that there is a risk that any new capacity charge would not be structured properly, which would create another channel for cost shifting to COS customers.

Staff agrees with PacifiCorp, writing that any requirement for the utility to make RA services available to DA customers appears, on its face, inconsistent with the legislature's directive to "eliminate barriers" to competitive retail markets.[31] To the extent the Commission does find it necessary to allow utilities to provide this service, Staff notes that IRP Guideline 9 provides that "[a]n electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electric suppliers."[32] Consequently, it says, a separate investigation would be required to explore solutions to these functional hurdles.

b. Resolution

We agree with PGE, Calpine, AWEC, and NIPPC that the utilities should be required to develop a capacity backstop product where the DA customer can pay to be included in the utility's RA load. However, we limit the availability of that capacity backstop charge and use of the capacity backstop product to a three-year duration, ending October 1, 2029. At that time, we expect ESSs to be participating in a resource adequacy program

[31] ORS 757.646(1).
[32] *In the Matter of Public Utility Commission of Oregon, Investigation into Integrated Resource Planning Requirements*, Docket No. UM 1056, Order No. 07-002 at 19 (Jan. 8, 2007).

and to stand on their own in this matter. It is our perspective that the DA business model must be reliable and incorporate the full cost of RA in order to avoid unnecessary cost shifting to COS customers.

We believe the record demonstrates a temporary need for a capacity backstop charge. Calpine witness Kevin Higgins testified, "there is strong evidence that it is not commercially feasible to procure WRAP-compliant resource adequacy from utilities or other market participants at this time in the Pacific Northwest for delivery to the Balancing Authority Areas of Oregon utilities."[33] Calpine further testified that it has issued requests for offers soliciting resource-adequacy-compliant capacity and supporting firm transmission, but it received no responses to its solicitations.[34] PGE points out that the landscape of RA has change significantly since we last considered this issue in 2020.[35] The record now demonstrates there are measurable RA requirements for all LSEs and the conditions that affect regional reliability have materially worsened.

In this landscape, we believe it reasonable to require the utilities to develop a short-term capacity backstop product for existing non-curtailable DA customers that are not currently paying transition charges. By paying a capacity backstop charge, DA customers who are no longer paying transition charges and cannot be curtailed, will be exposed to the same costs for maintaining reliability that COS customers are in the current environment. Our goal is to preserve the momentum for constructive evolution towards regional solutions, such as a regional, binding resource adequacy program that both business models can participate in equitably. In the interim, however, preserving a functioning DA program appears to require a temporary charge.

We agree with PGE that ESSs, as beneficiary of the newly acquired capacity, should pay the full amount of the costs. Cost should also be set to avoid cost shifting between DA and COS customers. We find that the appropriate way to do this, and one that will be practical on a short-term, interim basis, is to base the costs of the new RA product on avoided costs developed in the PURPA context. Specifically, the backstop charge should be based on the avoided capacity and transmission costs, as those elements have been identified in this record as the costly and scarce resources that ESSs cannot procure but the balancing areas must procure to preserve reliability. This balances the need for accuracy, as those costs are subject to rigorous vetting, with the need for administrability, as they will be readily available to participants.

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[33] Calpine/200, Higgins/7.
[34] Calpine Solutions/200, Higgins/7-8; Errata Calpine Solutions/202 (solicitation dated November 18, 2024); Calpine Solutions/203 (solicitation dated March 4, 2025).
[35] *In the Matter of Portland General Electric Company Advice No. 19-02, New Load Direct Access Program*, Docket No. UE 358, Order No. 20-002 (Jan. 7, 2020).

Staff points out that IRP Guideline 9 provides that "an electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electric supplier." On March 17, 2026, the Commission adopted modernized IRP rules which do not include an equivalent to IRP Guideline 9. Accordingly, we find that there is no longer a barrier in Commission rules to development of a short-term capacity backstop product

We understand that the product we order today will take some time to develop and direct the utilities to do so in new, utility-specific dockets. As this charge applies to existing DA customers, it must be implemented relatively quickly to address an existing cost and risk shifting issue. In order to expedite that process, we direct the utilities to file a product with prices based on the avoided cost of capacity and transmission. Where an ESS does not rely on the utility for transmission, the avoided cost calculation should be adjusted accordingly. We expect that the calculation will be similar to that used in developing avoided costs in the PURPA context.

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2. Who should be responsible for state RA compliance requirements for DA customers during the transition adjustment term? (Issue 5c)

a. Positions of the Parties

Calpine argues that the Commission should require that PacifiCorp and PGE be the RA provider for all DA customers still paying for the utility's fixed generation costs through transition charges. That would include customers in the one and three-year programs, as well as those in the five-year opt-out programs for the duration of the time that they pay transition charges. This proposal is reasonable, Calpine states, because these customers generally pay the same rates to the utility for fixed generation service as COS customers. NIPPC agrees, stating that otherwise, the transition adjustment would result in a double benefit to the utility in the form of freed-up capacity paid for by a DA customer. AWEC and Staff also agree.

PGE and PacifiCorp disagree. PacifiCorp states that the transition adjustment period provides a buffer for PacifiCorp to manage the economic consequences of a large commercial customer's departure from COS status. Conversely, providing backstop capacity during the transition period would, according to PacifiCorp, only delay the transition period following the DA customer's departure. PGE, for its part, argues that the transition adjustment charge has no correlation to an RA product, which is primarily a capacity product.

b. Resolution

We agree that PacifiCorp and PGE should be the RA provider during the transition adjustment period during the three-year interim period that the capacity backstop charge is also being charged. We find this proposal to be reasonable because, as Calpine states, customers are paying for fixed generation service through their transition charges. If load growth is consuming resources freed up by a DA customer that is still paying transition charges, then the utility will need to procure additional capacity, which the transition charges roughly account for. However, after the interim period described above, RA responsibility should shift from the utility to the ESS when the load shifts.

As noted above, setting out transition charges for five years, rather than annually reducing them based on how load grew to consume the freed up resources over twenty years may sometimes work to the favor of the utility and other times may work to the favor of the DA customer, but properly balances the risk of unnecessary cost shifting to COS customers with the removal of unnecessary barriers to DA. But if the utility must carry the RA obligation during the transition period, then the growing load requires additional capacity procurement to maintain compliance with an RA program up until the end of the transition period at which point, the utility will be holding more capacity than required by the load they serve.

H. Preferential Curtailment, Return to Cost-of-Service, and Default Supply

1. Is it necessary for DA customers to pay a Provider of Last Resort charge to the utility? (Issue 5a)

a. Positions of the Parties

AWEC proposes a POLR charge paid to the incumbent utility to reflect the cost of serving as a POLR; it would exempt legacy DA customers and DA customers electing to be preferentially curtailable from such a charge. A POLR charge would compensate the incumbent utility for maintaining its capability to serve DA customers with default supply and establish default supply rates.

Staff does not recommend that a POLR charge be paid to the utility. Calpine also opposes and states that the Commission's administrative rules expressly apply the default supply rates only to customers actually being served energy and capacity by the utility; the record, it states, does not support a further POLR charge. NIPPC also disagrees, stating that it would constitute a double benefit for the utility and a double charge for the DA customer. PacifiCorp also opposes AWEC's proposal.

b. Resolution

We do not require a POLR charge to be paid to the utility to reflect the cost of serving as a POLR, outside of the interim backstop capacity charge established for three years, above. While we appreciate AWEC's attempt to define a package of terms that would be acceptable for DA service, we believe the utility is being properly compensated through other means and decline to add an additional charge, finding it unnecessary either to encourage DA, to avoid cost shifting, or to ensure the utility is fairly compensated for its work. We particularly note that, based on our decision below, the utility is compensated above market rates for provision of POLR services when they are explicitly used, so there should be no question that its costs are covered and cost shifting will not occur.

2. Preferential Curtailment (Issue 6c-6j, 6o, 6p)

a. Positions of the Parties

Staff recommends that the eligible size for preferential curtailment be set at 10 MW at a single service point or in aggregate for customers with multiple service points. Staff believes that the operational challenges of curtailing loads less than 10 MW would not yield enough reliability benefit in an urgent situation to justify the necessary time and investment. PacifiCorp and PGE agree. PacifiCorp notes that during a time-sensitive and urgent situation where curtailment is needed, the company's personnel will be constrained by other acute operational activities. Under these conditions, it states, curtailing customers smaller than 10 MW would not yield enough relief to justify the time investment necessary to effectuate curtailment. PGE argues that a 10 MW curtailment threshold provides both a material reduction to the system when curtailment is necessary and it will reduce the number of individual facilities being curtailed, which leads to operational and staffing efficiencies.

NIPPC argues that no minimum size threshold for preferential curtailment should be imposed. NIPPC states that the only limitation is a practical one because customers have to invest in the equipment to be curtailable.

Staff recommends critical facilities submit documentation to the utility demonstrating the facility has adequate backup generation or other safety protocols to ensure reliability in the event of curtailment. Staff states that any disagreement between the customer and utility on whether the standards have been met should be resolved through a Commission determination. PacifiCorp agrees that critical facilities should be required to obtain a waiver and states that critical facilities include customers such as hospitals and other

medical facilities; emergency response providers; natural gas and other wholesale fuel provider processing, storage, or distribution facilities; sewage treatment plants; prisons, and military and other critical government facilities.

PGE argues that critical facilities should not be allowed to participate in the preferential curtailment program regardless of their back-up generation.

PacifiCorp argues that sixty days is the proper timeline for providing the estimated cost of outfitting the requesting customer with the equipment necessary to effectuate preferential curtailment. Staff and AWEC agree. PGE argues that 90 days is the appropriate timeline.

Staff and PacifiCorp believe 60 days is an appropriate timeline for deciding whether to be a curtailable customer after receiving an estimate of costs to become preferentially curtailable. PGE argues that 30 days is more appropriate.

AWEC argues that the utility should have one year to test and install preferential curtailment facilities. Staff agrees. Staff and AWEC agree that if the facilities are not ready within a year, the customer should move to DA service as a non-curtailable customer until the facilities are installed. PacifiCorp argues that there should not be a fixed deadline for installation of preferential curtailment facilities, writing that the time required to install equipment for preferential curtailment will depend upon the specific circumstances of each customer and external factors such as supply chain constraints.

Staff recommends that the customer is able to make a new curtailment election once every three years. Staff argues that a three-year timeline balances utility planning needs with customer desire for operational flexibility. Further, Staff states, the timing is similar to the period required for a customer to give a notice of return to COS in LTDA tariffs. AWEC agrees.

PacifiCorp does not propose a fixed waiting period between elections to participate in preferentially curtailable service options, but the company notes that elections may only occur during the designated election window and that consumers may only elect service to the extent there is space under the applicable cap.

Staff recommends a customer should have the choice to designate a separately metered portion of its load as either curtailable or non-curtailable while the other portion of its load is designated the opposite. Staff states the curtailable portion of the load must meet the minimum eligibility size. PacifiCorp agrees, as does NIPPC, AWEC, and PGE.

Staff recommends that preferential curtailment can be enacted under any of the following circumstances: (1) the utility's BA is in a position where operating reserves must be called upon; (2) the utility is unable to pass resource sufficiency evaluations or meet binding or non-binding RA obligations; (3) the utility has declared a reliability event that requires load shedding; or (4) there is insufficient import capacity to the utility's system.

PacifiCorp, for its part, would have the Commission find that participants can be curtailed by the utility if one of six criteria is met: (1) the ESS, if applicable, was not in compliance with binding, operationalized and enforceable RA obligations; (2) the PacifiCorp West balancing area is in a position where contingency reserves need to be called upon; (3) the company is unable to maintain resource sufficiency in an organized market; (4) the company is unable to meet all binding and non-binding RA obligations; (5) there is insufficient import capacity into the company's system to facilitate full service of all load and reserve obligations; or (6) the company has declared a reliability event that indicates the potential for load shedding (such as a Generation 1 Alert or a North American Reliability Corporation Emergency Alert Level 3).

PacifiCorp also argues that it should be able to curtail customers at will if they return to service without adequate notice from an ESS that was not compliant with its resource adequacy obligations at the moment of the consumer's default.

NIPPC requests the Commission's order clarify that the utility should provide at least 15 minutes' notice to allow a customer to prepare for curtailment and avoid damage.

AWEC proposes to repeal the rule providing for incremental capacity charges. AWEC argues that because a utility can curtail a preferentially curtailable customer, it does not incur any incremental capacity costs in serving that customer. It would go so far as to revise OAR 860-038-0290 to clarify that a preferentially curtailable customer should not be charged incremental capacity costs because the utility can curtail the customer in the absence of available capacity.

Staff supports retaining OAR 860-038-0290(11), which states that "[if] a returning curtailable consumer is served with Uncommitted Supply, the consumer will be charged the incremental capacity and energy costs or a market rate * * * *." Staff argues that if the customer is served with uncommitted supply when on default service, the capacity costs would recover the cost of serving that customer rather than just curtailing them. PGE agrees. PGE states that, considering the extremely limited circumstances that preferential curtailment would be used, it is necessary that the Commission allow PGE to continue to charge capacity costs both through the default service pricing and transition adjustment charges.

PacifiCorp does not propose in these proceedings to impose a demand charge on preferentially curtailable direct access load, but requests that the Commission reject AWEC's proposal to preclude future demand charges through a rule amendment.

NIPPC agrees, arguing that a preferentially curtailable customer should not be charged incremental capacity costs because those costs would be zero. NIPPC states that generally, a preferentially curtailable customer will be curtailable during times of stress, reducing a utility's overall capacity need and eliminating that need with respect to the curtailable load. Accordingly, NIPPC says, consistent with cost-causation principles, the customer should not have to pay for a benefit it provides to the utility.

Staff recommends that preferential curtailment infrastructure should not be prohibited from being used in a demand response program in the future but clarifies that demand response differs from curtailment given that curtailment is purely being used as a reliability safeguard.

PacifiCorp argues that enrollment in a DA preferential curtailment option is not equivalent to enrollment in a demand response program; the Commission should therefore treat preferentially curtailable DA programs and demand response programs as distinct and mutually exclusive. PGE agrees, writing that the infrastructure needed to implement the two programs is different, and that demand response does not accomplish the same goals that the Commission has for preferential curtailment.

NIPPC argues that customers should be eligible to participate in both programs.

b. Resolution

We set the size for preferential curtailment at 10 MW. We are persuaded by the evidence submitted that this size limit appropriately balances allowing DA customers to participate in the preferential curtailment program with the reliability benefits and operational limitations of preferential curtailment programs.

We find that critical facilities can participate in preferential curtailment without going through a waiver process. Customers large and sophisticated enough to elect curtailable DA service are large and sophisticated enough to judge whether they have the back-up generation or other arrangements necessary to allow them to safely participate in preferential curtailment, and we will not second-guess that decision.

We find that 60 days is a reasonable time frame to provide an estimate of costs to be preferentially curtailable after the customer's request; similarly, we find that the customer should have 60 days to execute an agreement to pay for the costs for becoming preferentially curtailable. The utility will then have a year to install and test the facilities. If the facilities are not ready after one year, the customer will move to DA service as a non-curtailable customer until the facilities are installed. We find this is a reasonable balance that allows DA customers to take service in a predictable and timely manner, removing unnecessary barriers to the DA program while still providing the utilities with sufficient time to complete facilities installation.

We find that customers can choose to switch between curtailable and non-curtailable DA service during the election window each year, provided space is available under program caps. We do not believe it is necessary for that choice to be available only once every three years and do not see an opportunity for arbitrage or cost shifting in a yearly election window.

DA customers may designate a portion of their load as curtailable and a portion as non-curtailable so long as (a) the curtailable portion meets the 10 MW minimum, and (b) the curtailable portion is separately metered.

We adopt Staff's list of potentially curtailable events, noting that only one item on the list needs to be fulfilled for preferential curtailment to occur. We find that Staff's criteria balance reliability with protections for the preferentially curtailable customer. We also find that PacifiCorp's criteria are too extensive, particularly while ESSs do not have a practical option for participating in a binding RA program.

We do not direct a proceeding to repeal OAR 860-038-0290 or to clarify it as AWEC requests. We will consider any charge PacifiCorp might bring under this section at the time it brings it before us. PGE may continue to charge capacity costs both through the default service pricing and transition adjustment charges.

We do not find that there is a need for us to decide whether preferentially curtailable customers can participate in demand response programs at this time. That will depend on the details of those programs, which are not in the record before us. We agree that preferential curtailment is distinct from demand response. Demand response programs may involve different equipment and do involve different incentives—demand response programs involve curtailment when the company can control its cost by avoiding expensive market purchases; preferential curtailment comes into play, as discussed above, when a reliability constraint is at play.

3. Default Service (Issue 6k-6n)

a. Positions of the Parties

PacifiCorp does not believe customers should be able to transition back to COS from default service faster than the notice of return period which, for PacifiCorp, is four years.

NIPPC argues that a returning customer should be allowed to transition to COS faster than the notice period, arguing that the service should be priced in such a way that it's consistent with cost causation principles. AWEC agrees, writing that PacifiCorp's concern about shortened planning time is mitigated due to AWEC's POLR charge for non-curtailable DA customers.

Staff recommends that after six months of service on default supply and not finding service through an ESS, the customer should be considered as having given notice to return to COS. PacifiCorp agrees.

PGE argues that a customer on default service can be returned faster than the two- to three-year notice period if the Commission waives IRP guideline 9. In the alternative, PGE asks for a more flexible, case-by-case analysis process whereby the company determines the timeframe under which it is able to serve returning load.

AWEC also recommends the Commission adopt a shorter period for notice to return to COS service. AWEC states that PacifiCorp's concern regarding sufficient planning time is mitigated due to AWEC's POLR charge for non-curtailable DA customers.

Staff states that customers on standard offer default supply should pay 125 percent of either Mid-C or EIM actual prices, plus a demand charge. However, customers who have given notice to return to COS should only pay 100 percent of either Mid-C or EIM prices plus the demand charge.

PGE proposes that the default rate be set at 150 percent of the higher on-peak or off-peak market energy prices using Mid-C or EIM, or another relevant index, aggregated by the same time period used in the customer's applicable rate schedule. PGE notes that this is a premium above market rate but states that the risk of setting the rate closer to market rate is that the rate does not account for the utility's exposure to real-time energy market volatility. Additionally, PGE says, the 150 percent rate reflects the risk of procuring supply under tight or emergency conditions and serves to prevent price arbitrage.

NIPPC argues that the default supply market rate should be calculated at the actual cost of power on the market, consistent with cost-causation principles. NIPPC states that setting the default supply rate above the cost of power on the market could lead to a windfall for the utility. Calpine also argues that the rate be set at the greater of 100 percent of the higher of on- and off-peak Mid-C index or EIM actuals for the period in which the consumer was served.

PacifiCorp proposes an energy charge for both preferentially curtailable and non-curtailable consumers who are served with uncommitted supply that would equal the greater of market rates or PacifiCorp's net power costs. More specifically, PacifiCorp states the charge should be the greater of (1) the company's Standard Daily Offer (Schedule 220), excluding the cost of thermal resources and recalculated so that the weightings by market hub equal 100 percent; or (2) PacifiCorp's Schedule 201 rate, which reflects the company's net power costs. PacifiCorp states this is consistent with the rule adopted in docket AR 651 that requires charges for direct supply to capture "the incremental capacity and energy costs or a market rate required to serve on less than the required notice of return" in the company's tariff, and that if the market rate was higher than the incremental cost then the returning consumer would be charged the market rate.[36]

Staff recommends using the cost of new entry (CONE) published by the WRAP administrator for the period the customer was served to calculate the capacity/demand charge on default supply. PacifiCorp and PGE agree that the CONE is appropriate. Calpine agrees but notes specifically that it recommends use of the annual CONE as published by the WRAP program administrator without escalation through application of WRAP's winter season and summer season CONE factors, in compliance with the WRAP tariff for the period in which the consumer was served.

NIPPC argues that the default supply capacity/demand charge should be calculated based on the actual cost of capacity on the market, consistent with cost-causation principles.

Calpine recommends an administrative charge of 2 mills per kWh but agrees that PacifiCorp's one-time fee of $5,000 would also be reasonable.

b. Resolution

We find that it is reasonable for PacifiCorp to require customers to wait out their return-to-service notice period of four years on default service to ensure the utility has time to plan for their return. We do not believe the return-to-service periods need to be

[36] OAR 860-038-0290(11), (14).

identical; if PGE believes it can offer a shorter period that is reasonable as well. We agree with Staff that after six months on default service, the customer should be deemed to have given notice of return to service. This is reasonable since a DA customer on default service can switch to another DA program or another ESS at any time during those six months.

We find that it is just and reasonable that customers on standard offer default supply pay 125 percent of either Mid-C or EIM actual prices, plus a demand charge; that premium will compensate the utility fully and prevent DA customers from returning to default service to pursue an opportunity for arbitrage. However, customers who have given notice to return to COS will only pay 100 percent of either Mid-C or EIM prices plus the demand charge as there is more opportunity for the utility to plan procurement for their load and less risk the DA customer is making program decisions for short term arbitrage value. A customer who elects to shift to DA service after giving notice of return to default service will be doing so as a new customer.

We also find that the CONE published by the WRAP administrator for the period the customer was served should be used to calculate the capacity/demand charge on default supply. We accept Calpine's clarification that it should be the annual CONE as published by the WRAP program administrator without escalation through application of WRAP's winter season and summer season CONE factors, in compliance with the WRAP tariff for the period in which the consumer was served.

Finally, we accept PacifiCorp's proposed one-time administrative charge of $5,000 as reasonable.

I. Availability of Legacy DA Requirements

1. Should current DA customers be given the opportunity to return to COS rates at the conclusion of this investigation? If yes, what DA rules should apply? (Issue 7a)

a. Positions of Parties

Staff recommends that, at the end of this case, DA customers will have 12 months to decide on whether they will return to COS without being subject to new DA requirements. If the customer decides to return to COS during that 12-month period, the customer will only be subject to legacy DA requirements during the notice of return period. Calpine agrees, but states that it should be symmetrical: DA customers who

already provided notice to return to COS during the pendency of this proceeding in 2025 should have the opportunity to rescind their notice and remain in the DA program.

PGE agrees. PGE states that it promotes customer choice and does not penalize a current DA customer for making economic decisions under a different regulatory regime. AWEC and NIPPC also agree.

PacifiCorp opposes Staff's proposal. PacifiCorp states that existing LTDA customers elected their programs based on the presumption that they would no longer be a part of PacifiCorp's system. There is, it says, therefore no need to give these consumers an opportunity to return to COS under the prior rules.

b. Resolution

Because terms and conditions of service are changing, we find it is appropriate to give customers a year to opt out of DA service, or to rescind a notice provided during the calendar year prior to this order. We agree with Calpine's rationale that providing the symmetrical opportunity is fair.

2. What reporting, if any, should utilities be required to provide regarding implementation of new DA requirements? (Issue 7b)

a. Position of the Parties

Staff recommends that at the conclusion of 12 months after the final order in this case, each utility is required to submit a one-time report to the Commission detailing the number of DA customers returning to COS, each customer's demand in aMW, and each customer's monthly generation in MWh over the previous year. Staff states that these reporting requirements fall within the Commission's authority in ORS 756.105 and will provide a window into how the policies adopted in this this proceeding impact Oregon's DA programs.

NIPPC supports annual reporting of subscription levels for each specific DA program, any and all DA loads operating pursuant to Commission waivers, and a comparison of DA loads to program caps to allow parties to assess whether the result of this investigation is consistent with the Commission's statutory obligation to facilitate DA and a competitive electricity market. Calpine agrees.

PGE argues that no party proposed reporting requirements in testimony and therefore adopting them at this stage of the case would not be supported by substantial evidence.

b. Resolution

We adopt Staff's proposed reporting requirement. We agree with Staff that these requirements fall within our authority in ORS 756.105 and will provide visibility into how the policies outlined here affect DA programs in Oregon to allow evaluation of the changes made here. We do not adopt an ongoing reporting requirement at this time.

VI. ORDER

IT IS ORDERED that:

1. Portland General Electric Company and PacifiCorp, dba Pacific Power, submit compliance tariffs consistent with the directives in this order within 60 days of this decision.

2. Portland General Electric Company and PacifiCorp, dba Pacific Power, each file a proposed capacity backstop product and charge with costs based on avoided PURPA costs within 90 days of this decision.

Made, entered, and effective May 07 2026.

Letha Tawney
Chair

Les Perkins
Commissioner

Karin Power
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.