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May 6, 2020

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of ALLIANCE OF WESTERN ENERGY CONSUMERS
Petition for a General Investigation into Long-Term Direct Access Programs.
Docket No. UM 2024

Dear Filing Center:

Please find enclosed the Closing Comments of Jon Wellinghoff on behalf of the Alliance of Western Energy Consumers in the above-referenced docket.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosure

JON WELLINGHOFF
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201 High St. SE, Suite 100
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Re: In the Matter of ALLIANCE OF WESTERN ENERGY CONSUMERS Petition for a General Investigation into Long-Term Direct Access Programs.
Docket No. UM 2024

CLOSING COMMENTS OF JON WELLINGHOFF ON BEHALF OF THE ALLIANCE OF WESTERN ENERGY CONSUMERS

I. INTRODUCTION

On behalf of the Alliance of Western Energy Consumers ("AWEC"), I appreciate the opportunity to provide closing comments to the Oregon Public Utility Commission ("OPUC" or "Commission") regarding the policy issues identified in Phase 1 of this proceeding. On February 18, 2020, the OPUC Staff filed a motion with a parties' issues list and proposal requesting the adoption of a phased procedural schedule in this docket. That Staff proposal has largely been adopted by Judge Allwein ("ALJ").[1/] Pursuant to that Staff proposal, the parties recommended and Judge Allwein ruled that in Phase 1 of this proceeding there be simultaneous initial comments and then simultaneous closing comments filed discussing certain policy issues relevant to long-term direct access. On March 16, 2020, parties to this proceeding filed their initial comments to Phase 1 issues. These closing comments of AWEC are filed in response to the initial comments filed by other parties in this proceeding.

[1/] The ALJ incorporated one addition to the Phase 1 bulleted issues list (*cost of legislative requirement)* and also added that topic to the Phase 2 briefing.

II. POLICY ISSUES OVERVIEW

The Parties to this proceeding were directed by the Ruling of the ALJ issued on February 20, 2020, to address a number of policy questions set forth for Phase 1 on the Parties' Issues List and Phasing Proposal adopted in that Ruling.[2/] Those questions were:

- What are the potential benefits and potential costs to customers from long-term direct access participation?
    - What are the potential cost shifts?
- How are other states handling customer choice and access to wholesale markets for different customer classes (with a focus on other WECC states, per Commissioner Tawney's request)?
    - Issues including:
        - provider of last resort obligations
        - price disclosure
        - data disclosure
        - general enforcement authority
        - pricing of departing load
        - market design and alignment with customer choice
        - oversight, compliance, and reliability responsibilities
        - capacity and reliability
    - What has worked well and what hasn't?
    - How can these findings be applied to Oregon, including consideration of the fact that Oregon's direct access market is limited to non-residential customers?
- Resource adequacy
    - What is it?
    - How is it provided?
    - What regulatory requirements or market structures are used in other states with direct access to ensure resource adequacy?
    - Why is it important or not important?

My response is structured to provide general comments addressing the comments and concerns of other parties. Then, in the following section, I address specific party comments, and provide AWEC responses to those individual comments.

[2/] Docket No. UM 2024, Public Utility Commission of Oregon Ruling (Feb. 21, 2020).

General Comments

1. Costs and benefits of direct access

As to the potential benefits from long-term direct access ("LTDA") participation by LTDA and new load direct access ("NLDA") customers, most parties agreed that there are substantial benefits from LTDA for both sets of direct access ("DA") customers and existing cost-of-service ("COS") customers. The exception was Portland General Electric ("PGE"), which was unwilling even to concede that there are *potential* benefits from LTDA customer participation for any customer class. PGE worked to develop and supported the issues list created for this proceeding, and like it or not, direct access is legally mandated in Oregon. It is disappointing to learn now that the utility is apparently uninterested in working constructively with the Commission and parties to develop LTDA programs that work for participants and protect non-participants. Without the constructive participation of a major stakeholder to this proceeding, the evidentiary record ultimately developed in this case and the Commission's options for modifying existing LTDA programs in the public interest will be impeded.

As I showed in my opening comments, DA provides benefits for participants and non-participants alike. DA customers have the benefit of lower energy costs from the provision of market-based retail energy services. Few would dispute that benefit; and, without it we would not be having this discussion before the Commission. In addition, AWEC provided additional substantial evidence of the multiple benefits to DA customers from their ability to directly access competitive retail energy suppliers in the Opening Comments filed in this Docket.

On the COS customer side, there are definite benefits, too, from an Oregon DA program. Oregon needs to attract business to maintain a vibrant economy. Yet, recent data on industrial rates shows Oregon's electric rates are the highest in the region with the exception of

California.[3/] A robust DA program for Oregon's commercial and industrial customers could provide new businesses with an economic incentive to relocate to Oregon. This, in turn, would induce related economic growth that would help spur COS load growth. This would benefit all Oregon citizens including COS customers. Again, additional evidence of the benefits to COS customers was provided in the AWEC Opening Comments.

2. Resource adequacy

On the issue of resource adequacy ("RA"), both PacifiCorp and PGE have conflated the concept of reliability or resource sufficiency[4/] ("RS"), a short-term days-to-minutes systems operations concept, with RA, a longer-term 1-4 year planning concept to assure adequate resources to provide service to loads.[5/] It is undisputed that a balancing authority ("BA") such as PGE has a FERC/NERC/WECC enforceable responsibility to operate its grid within its BA reliably under FERC enforceable rules. And this entails balancing loads and resources on a minute-by-minute basis within its BA. This would include the loads of its COS customers and its LTDA customers who are customers of PGE due to the use of the PGE transmission and distribution system. This would also include other PGE transmission customers under its OATT within its BA, such as McMinnville, Canby, or Forest Grove. But the only customer that PGE has a RA responsibility for is its COS customers. All others (McMinnville, Canby, Forest Grove, and LTDA) can and should contract separately for RA.

3/ See EIA data set at: https://www.eia.gov/electricity/data/browser/#/topic/7?agg=0,1&geo=0000000000a3&endsec=6&linechart=ELEC.PRICE.US-COM.M~&columnchart=ELEC.PRICE.US-COM.M~ELEC.PRICE.US-IND.M&freq=M&start=200101&end=202001&ctype=map&ltype=pin&rtype=s&pin=~~ELEC.PRICE.US-COM.M~ELEC.PRICE.US-IND.M~~&rse=0&maptype=0

4/ "A resource sufficiency framework is typically applied through a voluntary centralized market with multiple Balancing Authorities (BAs) that maintain their NERC reliability responsibilities to ensure fairness and equity among each BA." Northwest Power Pool, *Exploring a Resource Adequacy Program for the Pacific Northwest* at 45 (Oct. 2019).

5/ See, for example: Docket No. UM 2024, PacifiCorp Opening Comments at 15 (Mar. 16, 2020); Docket No. UM 2024, PGE Opening Comments at 10 (Mar. 16, 2020).

As this Commission has stated, RA should be the responsibility of all load serving entities ("LSE") in Oregon. In Oregon, as in other jurisdictions, an LSE can be either a monopoly provider such as an investor-owned utility ("IOU"), a municipal entity like McMinnville, or a co-op like the West Oregon Electric Co-op. In addition, an LSE can be an ESS that provides service to DA customers. In either case, one class of LSE should not be compelled, by regulation or otherwise, to take RA service from another class of LSE.

The Commission explicitly stated in its Order No. 20-002 that:

> We have a strong preference for solutions that give direct access customers the opportunity to choose how they support RA, whether that be through the utility, third parties, demand response, customer-sited resources, curtailment, or a combination.[6/]

The Commission also indicated that "…Oregon's direct access law permits us to require ESSs to comply with a RA standard."[7/] AWEC believes that such a standard should be developed by this Commission so that ESSs in Oregon will be able, under that standard, to demonstrate to this Commission that they are fully capable of providing RA for their DA customers. The incumbent monopoly which operates a BA need only provide transmission, and in some cases, distribution service to the ESS's DA customers and RS service to all loads within its BA.

3. AWEC's recommendation for a RA framework

With respect to developing a RA requirement for ESSs, AWEC recommends that the Commission consider the California Independent System Operator's ("CAISO") proposal in the California Public Utilities Commission's ("CPUC") ongoing RA rulemaking with respect to imports. The CAISO's comments are attached as Attachment A to these comments. The CAISO "recommends that the [CPUC] adopt a source specification requirement for all resource

6/ Docket No. UE 358, Order 20-002 at 9 (Jan. 7, 2020).
7/ Id. at 9.

adequacy-eligible imports at the time of resource adequacy showings."[8/] The CAISO defines "source specification to mean that the importer would 'provide specification of either the specific unit, aggregation of units, or the source balancing authority area' to qualify as a resource adequacy-eligible import."[9/] The CAISO further recommends a requirement for "firm transmission delivery for all resource adequacy imports at the time of monthly showings," though it notes this may be a difficult condition to satisfy in California and indicates its willingness to consider alternatives.[10/] AWEC intends to continue monitoring the progress of the CPUC rulemaking, but believes the CAISO's proposal establishes a reasonable framework for the Commission to consider if it develops a RA requirement for ESSs.

The CAISO's proposal, of course, only encompasses a high-level concept for a RA requirement for ESSs if one is adopted in Oregon. If the Commission moves forward with such a requirement, many details will need to be addressed. For instance, when does the ESS demonstrate compliance with the RA requirement? California has annual and monthly demonstrations. If Oregon follows California's system, and also adopts a source-specific requirement for RA products, should the ESS be locked into the sources it identifies in its annual demonstrations for that year, or can it modify the sources for monthly showings, so long as those sources remain in compliance with the RA standard? AWEC favors the latter approach as it ensures flexibility in the procurement of RA while still ensuring it is secured in a timely manner. This is just one example of issues that will need to be addressed when developing a RA requirement.

8/ CPUC Docket R.19-11-009, CAISO Comments on Track 1 Workshop Report and Proposals at 2 (Mar. 6, 2020).

9/ Id.

10/ Id. at 3.

III. REPLY COMMENTS TO SPECIFIC PARTY COMMENTS

In this section, AWEC provides comments to a number of the parties who submitted opening comments in this proceeding.

A. Portland General Electric Company:

PGE is largely content in its opening comments in this proceeding to repeat, without additional support or evidence, the arguments it offered in its NLDA program tariff filing in Docket No. UE 358. PGE even reasserts its position that it should provide RA for DA customers, despite the Commission's recent rejection of just such a proposal in UE 358. The Commission should be skeptical of PGE's motivations in taking this position, as it is an about-face from the position it has historically taken. PGE told this Commission something quite different in UM 1056 where the Commission indicated "…PGE states that utilities should not acquire long-term resources to serve expected direct access customers, but should be prepared to serve those loads with short-term resources as needed."[11/]

PGE fails throughout its comments in this docket to offer to the Commission meaningful substantive suggestions of how a standard framework for Oregon's DA program should be structured despite an explicit directive to do so.[12/] Instead PGE suggests that it is "…unfair for direct access customers to continue to lean on COS customers, … a position that the Commission, Staff, and some parties support."[13/] In support of this conclusion, PGE cites Order No. 20-002 with no page citation. There is no evidence presented by PGE which bolsters this bare statement, which is characteristic of PGE's opening comments as a whole.

11/ Docket No. UM 1056, Order No. 07-002 at 19 (Jan. 8, 2007).
12/ Docket No. UE 358, Order No. 20-002 at 8 (Jan. 7, 2020).
13/ PGE Opening Comments at 10.

1. Reliability

PGE asserts, as if true, "…neither ESSs nor new load direct access customers contribute to RA…."[14] Nothing new is offered here by PGE to support this statement beyond the repetition of its assertions in Docket No. UE 358. This statement is, of course, in direct contradiction to the findings of this Commission in its Order No. 20-002 where the Commission determined "…PGE's proposal is not justified on the record because PGE has not demonstrated that ESSs provide zero RA support at peak times."[15] The Commission in that Order went even further to find explicitly that "Parties have put forward credible evidence that the contracts backing ESS supply may in some way support regional RA."[16]

PGE also attempts to confuse this Commission by conflating RS and RA with statements such as "…even though PGE has to be there non-discriminately for all customers in an emergency, we are not permitted to plan for LTDA loads in our IRP."[17] Emergencies are RS or reliability events. As a BA, PGE must provide reliability for everyone in its BA, COS customers, DA customers, and muni and coop customers who rely on that BA for reliability service (and pay for these services). But planning is an RA function, and each LSE is responsible for providing RA service to its own retail electric customers.

PGE comments rely on the supposed intersection of its reliability responsibilities as a BA with RA responsibilities under the DA policy. At pages 16-17, PGE states:

> Ultimately, PGE is the BA and will effectuate its responsibilities to comply with all associated obligations and to provide safe and reliable electric service. Direct access policy must be reformed to enable PGE to satisfy its reliability obligations in a manner that is fair and equitable to all customers.[18]

14/ Id. at 5.
15/ Docket No. UE 358, Order 20-002 at 11.
16/ Id.
17/ PGE Opening Comments at 10.
18/ Id. at 16-17.

Once again PGE conflates RA and RS or reliability.[19] There are no "reforms" necessary of DA policy in order for PGE to satisfy its reliability obligations as a BA. Those obligations are prescribed by FERC rules overseen by NERC and WECC. The charges for PGE carrying out those FERC reliability requirements are FERC jurisdictional charges and not ones subject to the jurisdiction of this Commission. Whether those charges are "fair and equitable" (or in FERC parlance "just and reasonable") is a matter for FERC exclusively to determine.

PGE also suggests that as the Provider of Last Resort ("POLR") for customers in its service territory it is not now adequately compensated. The POLR function served by PGE is a tariff schedule (Schedule 81) function that provides for non-residential emergency default service at a tariffed rate approved by this Commission. As an approved tariffed rate, it is presumed to be just and reasonable and fully compensable to PGE for the costs it incurs under the tariff. PGE cannot now complain in this docket about its compensation under the tariff unless it files a fully allocated cost of service study and establishes that its filed rates under the tariff are not just and reasonable. PGE does at least admit that providing RA, reliability and its role as the POLR are different functions.[20]

PGE also complains that the Commission's current DA framework "…allows direct access customers to access standardized traded energy products on the wholesale market that are not backed by a specified physical resource."[21] This is despite the fact that "... it is a relatively common practice among utilities in the region [NWPP region including PGE] to assume that

[19] Despite intermixing the concepts of RS and RS throughout their opening comments, following the above reference, PGE asks the Commission and all parties to "…clearly delineate between RS and RA." See id. at 17.
[20] PGE Opening Comments at 11.
[21] Id. at 11.

some portion of their reliability needs can be met by market purchases on the wholesale energy market."[22/]

Regarding the use of short-term resources to provide for the RA needs of an ESS supplying its DA customers in Oregon, PGE states that "… short-term energy purchases should not be considered a substitute to capacity planning,"[23/] and would like this Commission to believe that:

> It is common practice that standard traded energy products are not explicitly linked to a physical resource. Instead, short-term transactions in the wholesale energy market are primarily "hub delivered" power with no specified source and only liquidated financial damages as remedy for failure to perform.[24/]

This would be true if one restricts the trade, as PGE did in its example, to the Intercontinental Exchange or ICE. ICE is a financial trading platform, not a physical one. It is true there is no physical asset backing the trade in a financial market. That is why it is a financial rather than a physical trading platform. But this is not to suggest that ESSs who provide RA to DA customers cannot and do not trade in the physical market in the West, which is as liquid and robust as the financial markets. In fact, the financial energy markets could not exist without the physical markets. As evidence of the fact that ESSs who currently provide DA services in Oregon are capable of providing physical RA capacity for their customers, one only need to look to the RA requirements in California for ESSs and other LSEs that requires "… documentation demonstrating that any RA import resource shown on annual and monthly RA and Supply plans represent physical capacity and firm transmission."[25/]

22/ Northwest Power Pool, *Exploring a Resource Adequacy Program for the Pacific Northwest* at 18. (Oct. 2019).

23/ PGE Opening Comments at 19.

24/ Id. at 19, citing a transaction at Mid-C on the Intercontinental Exchange ("ICE").

25/ CAISO RA 4th Revised Strawman Proposal, Executive Summary at 3 (Mar. 17, 2020), applicable to all LSEs including ESSs, some of whom also provide DA service in Oregon.

Indeed, PGE's complaints about DA customers' reliance on the short-term market is a red herring. Characteristic of its opening comments generally, PGE assumes, without evidence, that DA customers rely exclusively on the short-term market. This assertion, however, was directly contradicted by Calpine Energy Solutions' testimony in UE 358, which stated that Calpine "relies on firm liquidated damage ("firm LD") contracts executed well in advance of the delivery month."[26/]

In discussing other states and their RA efforts, PGE states about the ISO in Texas, ERCOT, "…ERCOT wholesale energy prices alone struggle to support the costs associated with adding generation capacity and supporting RA."[27/] However, NERC directly contradicted this allegation by PGE in NERC's 2019 Reliability Assessment where it stated: "Recent performance over the last several years has proven the ERCOT market and system operations to be successful with no load shedding events despite setting a new system-wide peak demand record of 73,308 MW on July 19, 2018, and another record of 74,666 MW on August 12, 2019."[28/]

It is suggested by PGE that energy service providers (California's equivalent to ESSs in Oregon) are somehow responsible for reliability challenges in California and are also responsible for the inability to meet adequate reserve margins in the market program design for RA in the state.[29/] This entirely mischaracterizes the situation in California. These RA issues were driven entirely by the rapid explosion of Community Choice Aggregation ("CCA") in California, which is not present in Oregon. There are currently over four million CCA customer accounts providing retail electric service in California. The majority of those accounts have been added in

26/ Docket No. UE 358, Calpine Solutions/200, Bass/3:8-9.
27/ PGE Opening Comments at 35.
28/ NERC 2019 Long-Term Reliability Assessment at 13-14
29/ PGE Opening Comments at 36.

the past 3 years. With respect to resource adequacy, those CCAs sought and signed over 3,600 MW of new market purchase power contracts over that period. The strain on the California RA program design is entirely due to this CCA explosion and is not the responsibility of ESPs or ESSs who primarily provide direct access to industrial and commercial customers in California.

PGE goes on to claim that the ESP/ESS providers in California are at risk of not meeting their RPS procurement requirements and thus their clean energy goals.[30/] A reading of the report PGE cites for support of its claim actually tells a different story. That report states:

> …of the 13 ESPs that will be serving load in the 2021 – 2024 Compliance Period, 10 have procured enough long-term energy to meet the 65 percent long-term contracting requirement. One has procured some long-term energy but needs to procure more to meet the requirement, and two have not procured any long-term RPS energy.[31/]

Thus, the report cited by PGE indicates that, contrary to not meeting their clean energy goals, 10 of 13 ESPs in California have fully met their RPS procurement requirements. Moreover, of the five ESSs registered in Oregon, three of them are part of the group of 10 in California that are in position to meet their long-term RPS requirements,[32/] while another (Avangrid Renewables) is not an ESP in California.[33/]

PGE complains that an ESS is not required to file an IRP with the Commission, arguing that will somehow lead to a less reliable grid.[34/] There is a reason that a monopoly utility like PGE is required to file an IRP and an ESS is not. It has nothing to do with reliability, but does

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30/ PGE Opening Comments at 44.

31/ Albright, Mallory, Cox, and Singh. "California Renewables Portfolio Standard: Annual Report - November 2019." California Public Utilities Commission. Nov 2019, page 20. Retrieved from: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-________Electricity_and_Natural_Gas/2019%20RPS%20Annual%20Report.pdf (internal citations omitted).

32/ These are: (1) 3 Phases Renewables; (2) Calpine Energy Solutions; (3) Shell Energy North America.

33/ Constellation NewEnergy is the only ESS in Oregon that is also an ESP in California that has not currently secured sufficient resources to meet its long-term RPS requirements in California.

34/ PGE Opening Comments at 30.

relate to RA or the long-term ability to serve its customers. As a monopoly, if PGE cannot serve its customers, they have nowhere else to turn. Regulatory oversight is therefore necessary to ensure the monopoly provider has adequately planned in the long term for their customers' needs and is doing so in a least-cost/least-risk manner in its customers' interest. An ESS on the other hand is a competitive provider. If an ESS does not reliably and economically plan for the needs of its customers for the term of their contract, it is unlikely that they will be in business for long. Therefore, competitive suppliers have an incentive to ensure that they can meet the RA needs of their customers in a least-cost manner. Monopoly utilities do not. IRP proceedings are about ensuring procurement decisions are prudent and cost effective. The market disciplines the competitive ESS procurement decisions, making an IRP process unnecessary.

2. Cost-Shifting

With respect to the issue of cost-shifting PGE asserts:

> The current framework allows LTDA and NLDA customers to bypass costs and unfairly shift costs to remaining COS customers. The Commission has used tools like participation caps, transition adjustments, and supplemental adjustment schedules to try and fulfil its statutory requirement not to cause "[...] unwarranted cost shifting of costs" from direct access customers to other retail electricity customers. These cost-shift mitigation tools are important, and contribute to a reduction in cost shifting, but are insufficient to prevent unwarranted cost shifting.[35/]

Here it is implied that the Commission's current DA program framework unfairly shifts costs to remaining COS customers and that it is insufficient to prevent unwarranted cost shifting. Nothing beyond bare assertions and repetition of arguments in other dockets is offered by PGE to support these assertions. No analysis is provided. No data is supplied. Once again, for instance, PGE complains about the five-year limitation on transition charges in its LTDA

[35/] PGE Opening Comments at 22.

program by advancing all of the same arguments it made in its last rate case when it sought to extend transition charges to ten years. In that case, the Commission "[did] not feel that the record before us supports a 10-year transition charge."[36] In its opening comments, PGE is doing the same thing and expecting a different result.

PGE also provides an extensive list of its supplemental schedules on pages 27 and 28 of its opening comments and alleges that DA customers avoid paying for all of the system and public benefits these schedules represent. What is most striking about PGE's list, however, is how many of them apply to DA customers. PGE identified only two that it felt DA customers unfairly avoided: Schedule 135 recovering demand response pilot costs, and Schedule 136 recovering community solar implementation costs.

With respect to Schedule 135, DA customers are prohibited from participating in the demand response ("DR") programs subject to this tariff, so it is perfectly logical that they are also exempted from their costs. In fact, the justification for the nonresidential demand response pilot was its ability to benefit COS customers: "The primary benefit [of this program] is that it provides a least-cost, demand-side … capacity resource, which increases reliability and avoids the costs of other capacity resources that PGE would need to build or acquire through contracts."[37] It was for this reason that DA customers were not allowed to participate in this program.

DA customers, however, can provide benefits to PGE through their participation in the utility's DR programs. In fact, as the transmission, and in many instances also the distribution, service provider the incumbent utility can reduce its costs by reducing the peak capacity on its

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[36] Docket UE 335, Order No. 19-129 at 19 (Apr. 12, 2019).
[37] Docket No. UM 1514, Exh. Stipulating Parties/100 at 12:5-7.

T&D equipment by contracting for DR services from the embedded DA customer. Further, the incumbent utility may be able to take advantage of the reduced peak generation capacity requirements created by that contract and import more capacity into its system to meet its COS customers' peak needs with appropriate contractual agreement from the DA customer's ESS. So the incumbent utility's DR opportunities may be diminished somewhat, but not in any substantial manner if that utility is fully cognizant of its options and takes advantage of them. It would, therefore, be appropriate in the future to assign the costs of these programs to DA customers on the condition that they are also allowed to participate in them.

With respect to Schedule 136, PGE does not explain why DA customers are exempted from the community solar program's start-up costs. It appears that PGE itself made this decision when developing Schedule 136, as AWEC has not identified any explicit direction to exclude DA customers from an allocation of start-up costs.[38/]

At page 31 of its opening comments, PGE further contends that "…LTDA and NLDA customers can bypass the costs of net-metering…"[39/] This statement assumes that the value of each increment of excess rooftop net metered solar is less than the retail rate. While this is a minor issue as it relates to cost-shifting associated with LTDA, given the extent of net metering in Oregon, if PGE believes that COS customers are subsidizing net metering customers, perhaps it should propose a transition charge for net metering rather than simply expanding the group of customers subject to cost-shifting.

38/ PGE recently requested in ADV 1112 that the Commission allow it to impose additional costs associated with the Community Solar Program on DA customers, specifically "bill credit payment costs." Because PGE did not raise these additional costs in its opening comments, AWEC does not address that issue here and will respond to PGE's filing in ADV 1112.

39/ PGE Opening Comments at 31.

PGE also claims that DA customers can bypass the costs PGE incurs to comply with the Public Utility Regulatory Policies Act ("PURPA").[40] PGE acknowledges that PURPA contracts are executed at the utility's avoided cost, thus ensuring that customers are indifferent to the procurement of QF power at that time, but complains that these contracts lock in a long-term price that may ultimately be above-market in the outer years. PGE's complaint, however, describes a risk associated with any long-term power purchase agreement or utility investment in generation – this investment may one day prove to be uneconomic. A direct access customer that enters into a long-term PPA would take on the same risk. If the DA customers' PPA is out of the money in certain years, the DA customer does not get to shift above-market costs to COS customers. Furthermore, DA customers do not receive any power cost benefits from a QF contract or other long-term PPA that is lower cost than the market. PGE's position would not only require DA customers to pay for PGE power costs (against the intent of the direct access law), but would do so in a way that shifts above-market cost risks to DA customers while reserving for its COS customers and shareholders all below-market benefits.

B. PacifiCorp

PacifiCorp contends that the retail independent purchasing of large customers as DA customers increases costs for other ratepayers. As evidence to support their contention, they directly extract a portion of a report done by a national trade association, Advanced Energy Economy ("AEE"), and cite that report. PacifiCorp states in their comments:

> Direct energy purchasing by large customers can increase costs for other ratepayers, as these large customers "defect" from existing utility-procured resources, leaving a smaller pool of ratepayers to cover embedded costs.[41]

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[40] Id. at 31-32.

[41] PacifiCorp Opening Comments at 4, citing: *Advanced Energy Economy (AEE) Report on Policies to Expand Corporate Access to Advanced Energy* at 16-17 (2017).

What PacifiCorp fails to tell this Commission is that the above citation from the AEE report is taken entirely out of context. The full citation from the AEE report is as follows:

> Depending on state-specific circumstances and without corrective measures, direct energy purchasing by large customers could result in increased costs for other ratepayers, as these large customers defect from existing utility procured resources, leaving a smaller pool of ratepayers to cover certain system costs. This is not an outcome that corporate purchasers want.[42/]

An examination of the PacifiCorp cited section of the report and the actual report itself reveals some startling differences. Apparently, DA may not result in increased costs for COS customers depending on the circumstances. Also, even if there are such increased costs, they can be mitigated with corrective measures. Finally, AEE states the increased costs to other ratepayers is not an outcome that corporate purchasers desire. This is certainly true for the membership of AWEC, which includes both DA and COS customers.

There are a number of other omissions by PacifiCorp from the AEE report that are worth pointing out to the Commission. First, there is the following:

> At the same time, there is a risk that steps taken to avoid departing load impacts on other customers will overcharge departing customers. It is therefore vital that lawmakers set clear parameters for measuring both the costs and benefits of a direct procurement arrangement to ensure that corporate customers are not overcharged for the impact of their departing load. States can meet the needs of all customers by implementing a transparent, straightforward, comprehensive, and fair process to assess the potential impacts of any direct access policy.[43/]

If the Commission intends to assess the potential costs and benefits of a DA program for existing and new load customers, as well as the remaining COS customers, then it is essential that it be done accurately and fairly so that charges and actions do not overcharge departing customers.

[42/] *Advanced Energy Economy (AEE) Report on Policies to Expand Corporate Access to Advanced Energy* at 16-17 (2017).

[43/] *Advanced Energy Economy (AEE) Report on Policies to Expand Corporate Access to Advanced Energy* at 17 (2017).

In that regard, the AEE Report concludes with an example DA procurement bill which contains guidelines for regulators in the development of standards for a well-constructed DA process. While the guidelines in the report are limited to a renewable/carbon-free direct access program, they are applicable to direct access more generally. The relevant portions of those guidelines are as follows:

> "3. To authorize direct transactions pursuant to subdivisions (1), (2), and (3), the [Commission and/or other relevant agency] shall do the following:
> a. Consider any capacity benefits, fuel hedging benefits, regulatory benefits, congestion reduction benefits, or other system or local area reliability benefits realized by all customers as a result of eligible retail nonresidential end-use customers pursuing renewable [or zero-carbon] energy according to this section; and
> b. Ensure that the costs of maintaining resource adequacy are equitably distributed, and allow for recovery of transition costs, provided that:
> i. The electric company has demonstrated diligent efforts to mitigate any transition costs;
> ii. Transmission costs account for benefits as determined per subdivision (3)(a);
> iii. Transition charges and transition credits may not be applied to any renewable [or zero carbon] direct access service serving a new nonresidential load; and
> iv. The [Commission and/or other relevant agency] adopts by rule a limited term, not to exceed five years, after which a customer eligible for renewable direct access may not be required to pay any transition charges. Transition charges applied before the end of the term may not carry forward any costs or expenses beyond the end of the term."[44/]

AWEC agrees with PacifiCorp that the AEE Report contains pertinent and useful material for this Commission to consider in the development of standards for ESSs and their DA customers in Oregon. But the entire report should be considered, and not just selected portions that would appear, out of context, to support the offered position of PacifiCorp.

44/ *Advanced Energy Economy (AEE) Report on Policies to Expand Corporate Access to Advanced Energy* at 36-37 (2017).

In its discussion of other states and RA and DA programs in those states, PacifiCorp mentions the efforts in Nevada to expand DA beyond current customers with loads of 1 MWa or more to all retail customers.[45/] Again, PacifiCorp fails to mention a few pertinent facts. It is true that the effort in Nevada "…to comprehensively overhaul and expand access to the competitive energy market was defeated in the 2018 election cycle."[46/] However, PacifiCorp does not tell the Commission this was only after the Nevada ballot measure to open retail competition to all COS customers passed in the 2016 election by over 72% of the vote[47/] and then Berkshire Hathaway, the parent of PacifiCorp, poured over $63 million, or $35 for every voter in Nevada, into the 2018 election to defeat retail energy choice for Nevadans.[48/] PacifiCorp also contends that the Natural Resources Defense Council ("NRDC") and the Sierra Club opposed retail choice in Nevada because it would undermine decarbonization efforts in the state.[49/] What PacifiCorp leaves out of its Nevada narrative is that the Berkshire Hathaway subsidiary, NV Energy, had to promise NRDC and the Sierra Club that it would develop 1.2 GW of new utility scale solar and 590 MW of new utility scale storage before those environmental groups would commit to oppose retail choice in Nevada.

PacifiCorp implies that ESSs will "lean" on regulated utilities in the region for backstop or rely on the markets to provide "extra" resources when contingencies occur.[50/] As with PGE, this is an instance of conflating RS and RA. First, "contingencies occur" when there are RS or reliability problems. It is the BA who has the responsibility for maintaining reliability in times

45/ PacifiCorp Opening Comments at 12.
46/ Id.
47/ See:https://www.nytimes.com/elections/2016/results/nevada-ballot-measure-3-open-electric-energy-market
48/ See:https://www.nvsos.gov/SOSCandidateServices/AnonymousAccess/ViewCCEReport.aspx?syn=cyh1qSgeFPWg4%252fkynehlUA%253d%253d
49/ PacifiCorp Opening Comments at 12.
50/ Id. at 16.

of contingency problems, not non-BA LSEs (and non-BA LSEs pay the BAA for these services through OATT charges). In times of contingency problems, BAs do "lean" on each other occasionally, but are generally prohibited from doing so by FERC/NERC/WECC requirements, and can be fined for doing so excessively. As for relying on wholesale markets to provide a portion of reliability needs, this is a relatively common practice for utilities in the Northwest region.[51] In fact a report by the Northwest Power Pool on RA indicated that "…Relying on market purchases [for RA] can be beneficial in that doing so captures the load and resource diversity across the region."[52]

C. Commission Staff

Commission Staff seem to be concerned in their Opening Comments that some DA customers will have lower levels of reliability requirements than traditional COS customers serviced from the monopoly utility provider; and, as such they will seek out ESSs who provide a lower level of reliability service which will then somehow impact system reliability and RA for the remaining COS customers.[53]

Again, reliability or RS is not the responsibility of all LSEs, only those that are BAs. ESSs are not traditionally BAs. Therefore, Staff's concerns regarding a DA customer seeking an ESS with a lower level of reliability or RS is not well grounded in existing requirements for reliability by FERC/NERC/WECC. ESSs do not offer levels of reliability. Reliability is something provided by BAs and must be offered at the standards required by FERC/NERC/WECC.

51/ Northwest Power Pool, *Exploring a Resource Adequacy Program for the Pacific Northwest* at 18 (Oct. 2019).

52/ Id. at 29

53/ Docket No. UM 2024, Staff Opening Comments at 6 (Mar. 16, 2020).

Additionally, Staff provides no example of a large customer that has pursued DA looking for a lower level of reliability. AWEC can affirmatively represent that, if anything, large customers are *more* concerned with reliability than other customer groups. An unexpected outage to a manufacturing facility can have major consequences, often requiring the facility to be offline for an extended period as the process is restarted. While it is the case that some large customers can turn their processes off quickly, and elect to be served under interruptible tariffs, those interruptions still require some amount of prior notice from the utility in almost all circumstances so that the customer interrupts in a safe and orderly manner.

Staff could legitimately raise the concern of whether a particular ESS has an adequate level of RA or long-term preparedness for meeting the load needs of its customers. Staff alludes to this issue by suggesting a DA customer might contract with an ESS for large levels of variable solar and wind resources that may not have sufficient coincident peak capacity factors to meet the DA customer's peak loads.[54/] Even if this were something that a DA customer would do, thus intentionally jeopardizing the operation of it facilities and its revenues, it is an unlikely event that the Commission could easily protect against with appropriate RA standards for ESSs as suggested above.

One final point made by Staff regarding potential cost shifts that DA customers may impose on the remaining COS customers is worth comment. Staff indicates there may be potential cost shifts from "…foregone electric company demand response program opportunities."[55/] As discussed in response to PGE's opening comments, however, DA customers can contribute to the utility's DR programs, and should be allowed to do so.

54/ Staff Opening Comments at 6.

55/ Id.

D. Oregon Citizens' Utility Board

The Oregon Citizens' Utility Board ("CUB") argues in its opening comments that cost-shifting from LTDA is occurring today. CUB's primary basis for this position is its belief that markets in the Northwest are exclusively energy markets and, by relying on them, DA customers avoid paying for the capital cost of generation that COS customers pay for. CUB's position, however, is only arguably valid with respect to the spot market. To the extent an ESS secures the resources needed to serve its DA customers' loads months or even years ahead of time, the ESS acquires not only the energy from these resources, but also their capacity. This is evident from the fact that forward market prices are almost invariably higher than spot market prices. The cost of securing resources in the future is higher than securing them in the moment because the purchaser in the forward market acquires the right to receive the output from these resources, not just any residual energy that exists in real-time. That is why many utilities in the Northwest, including PacifiCorp and Puget Sound Energy, rely on these markets for capacity and include this capacity resource in their integrated resource plans.

CUB also identifies several other alleged cost shifts, many of which PGE also raised and are discussed above, including net metering, PURPA, and demand response. In addition, CUB raises two other alleged cost shifts: energy efficiency and coal plant decommissioning costs. With respect to energy efficiency, however, CUB's assertion of cost shifting has nothing to do with direct access. The statutory limitation on energy efficiency funding that CUB references applies to all customers with loads over 1 aMW, whether they are direct access customers or not. This is simply not a direct access issue.

With respect to coal plant decommissioning costs, there may be circumstances where it is appropriate to impose some of these costs on certain DA customers, but an equitable allocation of costs is complex and case-specific. For one, under no circumstances should NLDA customers bear these costs as they never received benefits from the coal-fired resources. With respect to LTDA customers, the question becomes one of allocating costs commensurate with the benefits received. PGE's LTDA customers pay the Boardman decommissioning adjustment tariff during the transition period, so many of these customers may already be paying their fair share of decommissioning costs. However, this is an issue that likely deserves attention during the contested phase of this proceeding.

E. NWPCC

The Northwest Power and Conservation Council ("Council") generally indicated in its comments concern that planned retirements in the region of existing generation resources will leave the region resource short in 2021 and beyond. Due to retirements, the region will be resource short in 2021 at 7.5% and thereafter according to the Council. The Council went on to state that DA customer loads can impact resource adequacy and the Commission should consider those load impacts in RA determinations.[56/]

It goes without saying that all loads under the jurisdiction of the Commission, including the loads of DA customers, should be considered in developing an RA standard for the state. But DA customer loads, whether they be from existing LTDA customers, existing monopoly utility COS customers who choose in the future to become LTDA customers, or NLDA customers, pose no more risk to RA in Oregon than do COS customers as long as the Commission incorporates requirements for RA for all customer loads within each BA in Oregon. To suggest that DA customers somehow pose a higher risk to RA in the state is unfounded and unsupported by the

56/ Docket No. UM 2024, Opening Comments of Northwest Power and Conservation Council at 4-5 (Mar. 16, 2020).

evidence. If anything, these customers, who largely are composed of sophisticated industrial and large commercial enterprises, have the capability to shift and/or reduce loads at times of regional resource strain and thereby reduce RA risk on the system to a greater degree than less flexible or elastic small commercial and residential COS customers.

IV. CONCLUSION

As demonstrated by the evidence provided in these comments, ESSs who serve DA customers in Oregon are fully competent and capable of providing RA services for those customers. ESSs must have the ability to demonstrate RA to their potential customers or they will never secure customers. That is what competitive DA is all about. It is sophisticated, competent, market-proven sellers contracting with sophisticated, willing, arms-length buyers.

As for the claims of PGE and others that ESSs have no obligation to plan for adverse scenarios, thus putting reliability for all customers at risk, that is beside the point. First, in the short term that is the job of the BA and not the ESS. The BA utility must ensure their system meets FERC requirements for reliability. For the longer term, ESSs have every incentive to meet the RA needs of their existing and prospective customers. They must do so to hold onto existing customers and to hope to acquire new customers.

The Commission should not be confused by the continued conflation of reliability or RS and RA in the utility comments submitted in this proceeding. Short-term reliability and RS service is the job of the BAs and T&D owner/operators. Costs associated with those RS functions should be equitably spread over all users of the T&D system. Long-term RA services should be a function of the entity providing the retail service of suppling energy and capacity and should be appropriately incorporated into the charges for those services. ESSs should be allowed to provide RA services and determine the appropriate market-based charges for those services.

If the Commission adopts a RA standard for ESSs, or more generally, it should consider the framework proposed by the CAISO in the ongoing CPUC rulemaking, which would establish a source-specific requirement – meaning a specific unit, aggregation of units, or the source balancing authority area – and a firm transmission requirement.

Dated this 6th day of May 2020.

Respectfully submitted,

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**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Forward Resource Adequacy Procurement Obligations.	Rulemaking 19-11-009 (Filed November 7, 2019)

**CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
COMMENTS ON TRACK 1 WORKSHOP REPORT AND PROPOSALS**

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CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION COMMENTS ON TRACK 1 WORKSHOP REPORT AND PROPOSALS

I. Introduction

The California Independent System Operator Corporation (CAISO) submits comments on the Track 1 proposals submitted pursuant to the January 22, 2020 Assigned Commissioner's Scoping Memo and Ruling (Scoping Memo). The CAISO emphasizes that any new rules adopted in this proceeding should require that resource adequacy imports provide reliable capacity from physical resources that are not dedicated to other balancing authority areas. The CAISO's February 28, 2020 Track 1 Proposal (CAISO Proposal) provides a number of complementary mechanisms to accomplish this goal, but the foundational elements of the CAISO Proposal are (1) a source specific information requirement at the time of the resource adequacy showings, together with requirements for appropriate attestation or other supporting documentation to validate that shown capacity is backed by real, physical resources in excess of the supplier's or balancing authority area's existing capacity commitments; and (2) an extension of the CAISO's Must Offer Obligations[1] to the Real-Time Market for resource adequacy imports included in resource adequacy showings. The Commission should adopt updated resource adequacy import rules that require load-serving entities to provide source specific information at the time of resource adequacy showings. In concert with the Commission rule changes, the CAISO will pursue similar rules for supplier showings and changes to its Real-Time Market Must Offer Obligations for resource adequacy imports.

[1] Terms not otherwise defined herein are used as defined in the CAISO tariff.

The CAISO disagrees with Southern California Edison Company (SCE) and Shell Trading (SCE/Shell Joint Proposal), which recommends that the Commission should consider resource adequacy import proposals designed only to address energy market price risks without addressing the fundamental need to require real, physical capacity. If the Commission finds it necessary to consider hedging mechanisms for energy contracts, these energy pricing guidelines should not be conflated with capacity contracting and are not a substitute for source specification requirements to secure real, physical capacity in advance.

II. Discussion

A. The Commission Should Adopt Source Specification Requirements for Resource Adequacy Imports.

The CAISO Proposal recommends that the Commission adopt a source specification requirement for all resource adequacy-eligible imports at the time of resource adequacy showings. The CAISO Proposal further defines source specification to mean that the importer would "provide specification of either the specific unit, aggregation of units, or the source balancing authority area" to qualify as a resource adequacy-eligible import. Proposals submitted by Morgan Stanley and Powerex would establish similar "source specific" resource adequacy import products.[2] The CAISO continues to believe the Commission should require source specification and related attestations and/or documentation to ensure resource adequacy imports provide real, physical capacity.

The Commission should not accept energy products without source specification as resource adequacy-eligible resources. Both Morgan Stanley and the SCE/Shell Joint Proposal would allow import energy contracts to count toward resource adequacy requirements without source specification.[3] These proposals are inadequate to address the speculative supply and double counting issues that the CAISO Proposal addresses. As overall capacity in the West continues to tighten, the speculative supply and double counting issues will only increase, leading to potential capacity shortfalls during periods of high west-wide demand. The Commission and CAISO resource adequacy programs should ensure that on a going-forward basis there are adequate capacity resources to serve California demand. If the Commission

[2] Track 1 Proposal of Morgan Stanley Capital Group Inc. Regarding the Scope, Schedule, and Administration of R.19-11-0019 (Morgan Stanley Proposal), p. 6; Track 1 Proposal of Powerex Corp., p. 16.
[3] Morgan Stanley Proposal, p. 8.

continues to allow unspecified short-term energy purchases to satisfy resource adequacy delivery obligations, California will not reduce its reliance on the short-term energy market for its reliability.

In addition to source specification and attestation requirements, the CAISO Proposal recommends that the Commission and CASO require firm transmission delivery for all resource adequacy imports at the time of the monthly showings. Other party proposals raised concerns about the availability and liquidity of firm transmission rights from the Pacific Northwest. The CAISO understands that the market for firm transmission rights may be constrained and that requiring firm transmission rights at the time of monthly showings may not be economically feasible. Though requiring firm transmission rights at the time of monthly showings would help ensure a reliable, deliverable capacity product, there may be alternatives that also ensure that available transmission capacity will be available to serve resource adequacy imports, and the CAISO is not averse to exploring such alternatives.

B. The CAISO Does Not Intend to Pursue Tariff Modifications to Implement Strike Prices or Bid Caps for Resource Adequacy Imports.

The SCE/Shell Joint Proposal recommends that the CAISO implement a maximum strike price for resource adequacy imports at a level below the current CAISO energy market price cap. This strike price would be tied to prevailing natural gas prices. The SCE/Shell Joint Proposal suggests that the "most effective way to implement this proposal is through CAISO tariff modification, which would amend existing must-offer obligation and bid insertion rules such that the bid price of an import RA resource will not exceed the proposed strike price."[4] Although the Commission can consider price hedging mechanisms applicable to contracts signed by its load-serving entities, the CAISO does not intend to pursue tariff modifications to implement strike prices or bid caps for resource adequacy imports participating in its energy markets.

The CAISO supports load-serving entities entering into energy hedging contracts, but such contracts can and should be separate from resource adequacy contracts. The CAISO is concerned that including bid caps in all Commission-jurisdictional resource adequacy contracts may prove counter-productive, either by deterring competitive resources from participating in California's resource adequacy program or by increasing capacity prices. Unlike internal

[4] SCE/Shell Joint Proposal, p. 6.

resource adequacy supply, resource adequacy imports compete in a west-wide market and have not been historically committed to meeting CAISO energy needs. As such, the Commission should encourage energy hedging mechanisms and contracts, but should carefully weigh the implications and consequences of embedding a strike price in every resource adequacy import contract.

The CAISO notes that its proposal to address speculative supply issues will also mitigate energy bidding and market power concerns. As the CAISO Proposal notes, if the Commission requires capacity contracts backed by real physical resources, suppliers will have an incentive to bid marginal costs resulting in an efficient energy dispatch in the CAISO's day-ahead and real-time energy markets. In contrast, sellers providing speculative import supply have an incentive to submit high energy bids to avoid dispatch.

III. Conclusion

The CAISO appreciates this opportunity to provide comments on Track 1 proposals and looks forward to working with the Commission and parties to ensure that imports continue to meet resource adequacy needs.

Respectfully submitted

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