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March 16, 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 Alliance of Western Energy Consumers' ("AWEC") Opening Comments in the above-referenced docket. Included as Attachment A to AWEC's comments are the Comments of Jon Wellinghoff on behalf of AWEC.

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

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2024

In the Matter of ALLIANCE OF WESTERN ENERGY CONSUMERS, Petition for a General Investigation into Long-Term Direct Access Programs.	))))))))	OPENING COMMENTS OF THE ALLIANCE OF WESTERN ENERGY CONSUMERS

I. INTRODUCTION

Pursuant to the Administrative Law Judge's February 21, 2020 Ruling, the Alliance of Western Energy Consumers ("AWEC") submits these Opening Comments on long-term direct access issues. These comments focus on how other states in the Western Electricity Coordinating Council ("WECC") region address direct access. The accompanying comments of Jon Wellinghoff, included as Attachment A hereto, address the benefits and costs of long-term direct access and resource adequacy.

Before addressing the issues identified for Phase 1 of this proceeding, AWEC believes it is important for the Commission to establish a goal for this docket, and principles for achieving it. In its Petition to open this docket, AWEC proposed that this investigation "ensure viable long-term direct access programs that work for both participating and non-participating customers."[1/] AWEC continues to support this goal, and believes that its achievement will be

[1/] AWEC Petition at 6.

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evidenced by: (1) a determination, based on evidence and policy considerations, of the universe of customers that should be allowed to participate in a long-term direct access program; and (2) if not already addressed by the existing long-term direct access program, the development of criteria and conditions on long-term direct access participation that ensure to the Commission's reasonable satisfaction that any eligible customer can participate without shifting costs in an unwarranted manner to non-participating customers.

To achieve the goal identified above, AWEC proposes that the Commission be guided by the following principles:

1. Only fix what is broken: Based on testimony and comments from parties in other dockets, AWEC expects (and believes itself) that PGE's and PacifiCorp's current long-term direct access programs need revision. That does not, however, mean that they need to be scrapped entirely. It is just as important for the Commission to identify what works under the current programs, and retain those aspects, as it is to identify what does not work, and modify those aspects.
2. Keep it simple: As demonstrated most clearly by California's numerous and lengthy processes related to retail choice, the Commission could allow itself to get bogged down in highly technical minutiae, the resolution of which may not be materially impactful. AWEC recommends that the Commission focus its attention on the most important elements of a long-term direct access program and leave the more detailed or utility-specific elements to the utilities' tariff filings or for resolution in future proceedings, like a utility's general rate case.

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3. Do not let perfect become the enemy of good: Parties to this docket will inevitably disagree on some issues, but just because a party can identify a potential downside to another party's proposal does not mean this proposal should be rejected. If the proposal is nevertheless an improvement over the status quo, then it deserves consideration.

II. COMMENTS

A. How are other states handling customer choice and access to wholesale markets for different customer classes?

1. California

California has been wrestling with customer choice issues since at least the 2000-2001 Energy Crisis. The California Public Utilities Commission ("CPUC") has held multiple, lengthy dockets addressing the impacts of various forms of customer choice. In reviewing these processes for their applicability to long-term direct access programs in Oregon, it is important to recognize two distinctions between California and Oregon.

First, California has Community Choice Aggregation ("CCA") in which an entire community (from residential to large industrial customers) can exit their incumbent utility collectively. This creates unique issues that are not necessarily applicable to a long-term direct access program open only to large customers.

Second, the CPUC is subject to certain statutory requirements that do not exist in Oregon. For instance, Section 365.1 of the California Public Utilities Code imposes a cap on the amount of traditional direct access load. During the energy crisis, California authorized the Department of Water Resources ("DWR") to procure electricity for the investor-owned utilities' ("IOUs") customers. To ensure a stable customer base to repay DWR for these high-cost

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contracts, the legislature prevented additional direct access participation. As another example, Section 380 of the Public Utilities Code requires the CPUC to adopt resource adequacy requirements for all "load serving entities," including direct access suppliers.

Nevertheless, the extensive work the CPUC has done to implement its various customer choice programs can be instructive for the Commission as it explores modifications to PGE's and PacifiCorp's long-term direct access programs. The California Customer Choice Project estimated that, as of 2018, as much as 25% of load connected to the State's IOUs' distribution systems was served by rooftop solar, direct access, CCAs, or direct ownership of offsite generation.[2/]

a. Cost-Shifting

California law requires the CPUC to "ensure that bundled retail customers of an electrical corporation do not experience any cost increases as a result of retail customers of an electrical corporation electing to receive service from other providers … [and] that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load."[3/]

To implement this statute and prevent cost-shifting from a customer's election of direct access, the CPUC has developed a Cost Responsibility Surcharge ("CRS"). The CRS includes several components, some of which are unique to a particular IOU,[4/] and others of which are specific to California's circumstances.[5/] Potentially the most important component of

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2/ California Customer Choice Project, "Choice Action Plan and Gap Analysis" at 47 (Dec. 2018).
3/ Cal. Pub. Utils. Code § 365.2. A similar law applies to CCAs. Cal. Pub. Utils. Code § 366.3.
4/ Pacific Gas & Electric's CRS, for instance, includes an Energy Cost Recovery Amount associated with PG&E's 2001 bankruptcy.
5/ These include the DWR Bond charge and the Ongoing Competition Transition Charge.

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the CRS, however, is the Power Charge Indifference Adjustment ("PCIA"), which is similar in concept to the transition adjustment charges PGE and PacifiCorp currently employ in their long-term direct access programs, but with some important differences. The PCIA takes the total costs of a utility's portfolio and subtracts the market value of this portfolio. The market value of the portfolio, known as the "Market Price Benchmark" is calculated based on: (1) forward market prices (the "brown power" index); (2) a capacity adder to reflect the cost of resource adequacy; and (3) an RPS adder designed under the assumption that resources procured to meet the State's RPS would be higher cost than conventional alternatives. Any positive difference represents the PCIA charge a direct access customer (and CCAs) must pay to hold other customers harmless.

The PCIA has been the subject of significant litigation and revision over the years. Its current form was established by the CPUC in Decision 18-10-019, issued on October 11, 2018. There, the CPUC modified the PCIA in four important ways. First, it modified calculation of the RPS adder by using reported prices of purchases and sales during the year that is two years prior to the forecast year.[6/] Second, it modified calculation of the capacity adder by using transaction data during the year prior to the delivery year, with any capacity expected to remain unsold given a $0 price.[7/] It also incorporated three different types of resource adequacy into the calculation of the capacity adder.[8/] Third, it capped the amount the PCIA could increase in a year to $0.005/KWh, with any increase above this amount deferred and tracked in a

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6/ CPUC Docket No. R.17-06-026, Dec. No. 18-10-019 at 73 (Oct. 19, 2018).

7/ Id.

8/ Id. at 74. The three types of resource adequacy are: (1) system; (2) local; and (3) flexible.

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balancing account.[9] Fourth, it approved a true-up to reconcile the difference between forecasts informing the PCIA rate and the actual prices realized. This true-up methodology was separately considered and determined in Decision No. 19-10-001, issued on October 17, 2019 in the same docket. Fourth, it removed the 10-year limitation on cost recovery from direct access customers.

In removing the 10-year limitation on cost-recovery from direct access customers, the CPUC agreed with the State's IOUs that the obligation of direct access customers to pay for existing resources should apply for as long as procurement costs continue to exist.[10] The CPUC also, however, recognized certain parties' concerns that irrevocably committing direct access customers to the utilities' generation reduced incentives for these utilities to optimize their portfolios, to the benefit of cost-of-service customers, in response to departing load.[11] The CPUC, therefore, committed to working toward utility portfolio optimization and cost reduction in a separate phase of the docket, which remains ongoing.

b. Resource Adequacy

Please refer to the comments of Jon Wellinghoff on behalf of AWEC for a discussion of California's resource adequacy ("RA") program. California is undergoing several processes to consider potential changes to the RA rules Mr. Wellinghoff discusses.[12]

i. CPUC rulemaking

The CPUC instituted a rulemaking on September 28, 2017 regarding its RA requirements. An important issue in the rulemaking is the requirements applicable to using

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9/ Id. at 86.
10/ Id. at 54-59.
11/ Id. at 59.
12/ CPUC Docket No. A.19-04-026.

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imported power supplies to satisfy RA requirements. The RA import rules were first adopted by the CPUC in 2004 in Decision 04-10-035. That decision provided that imported capacity acquired pursuant to a contract that was not tied to a specific resource could qualify for RA, "provided the contract:

1. Is an Import Energy Product with operating reserves;

2. Cannot be curtailed for economic reasons; and

3a. Is delivered on transmission that cannot be curtailed in operating hours for economic reasons or bumped by higher priority transmission, or

3b. Specifies a firm delivery point ([i.e.] not seller's choice)."[13/]

In a later decision, the CPUC established that non-unit specific, liquidated damage ("LD") contracts would be phased out of use in the RA program, due to the possibility of double-counting resources. However, the CPUC exempted firm import LD contracts from the sunset/phase-out provisions applicable to other LD contracts, noting that "firm import contracts are backed by spinning reserves."[14/] To ensure that import rules are followed, the CPUC requires that load-serving entities ("LSEs") (including direct access suppliers) provide documentation in their current RA compliance filings that reflects that the unspecified imports being submitted to meet RA requirements have firm energy delivery and operating reserves behind them. The CPUC has specified that this documentation can be in the form of contract language or an attestation from the import provider that confirms the import is supported by firm energy and operating reserves.

13/ Decision 04-10-035 at 54 (April 1, 2004).
14/ Decision 05-10-042 at 68 (Oct. 27, 2005).

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After a notice and comment process in the rulemaking proceeding, the CPUC issued Decision 19-10-02 on October 10, 2019. Although the decision purports to "affirm" the existing RA requirements as set forth in Decision 04-10-035 and Decision 05-10-042, the Commission made one significant clarification, stating that energy that "is available only when called upon in the CAISO's day-ahead market or residual unit commitment process does not qualify as an "energy product" that "cannot be curtailed for economic reasons." Based on this conclusion, "the Commission affirm[ed] the requirements for RA import contracts established in D.04-10-035 and D.05-10-042, with the clarification that an 'energy product' that 'cannot be curtailed for economic reasons' is required to be self-scheduled into the CAISO markets, consistent with the timeframe established in the governing contract."[15/]

According to many of the parties in the rulemaking proceeding, the CPUC's clarification effectively converts the current must-offer obligation for RA resources into a must-deliver obligation. They claim that this will result in the scheduling of RA resources when they are uneconomic. A number of parties, including the CAISO, requested rehearing and a stay of Decision 19-10-02. On December 19, 2019, the Commission granted the motion to stay, but no action has been taken on the request for rehearing.[16/]

ii. CAISO RA Enhancement Process

On October 22, 2018, the CAISO initiated a stakeholder process to modify the RA requirements of the CAISO Tariff. The CAISO Tariff applies to all LSEs in the CAISO,

[15/] Decision 19-10-02 at 8 (Oct. 10, 2019).
[16/] Decision 19-12-064 (Dec. 19, 2019).

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regardless of whether they are subject to CPUC jurisdiction. The CAISO generally follows the rules developed by the CPUC for RA.

Under the current CAISO Tariff, RA imports are not required to be resource specific or to represent supply from a specific balancing area, but only that they be on a specific intertie into the CAISO system. Further, scheduling coordinators are only required to submit energy bids for resource adequacy imports in the day-ahead market. Imports can be bid at any price and do not have any further obligation to bid into the real-time market if not scheduled in the day-ahead energy or residual unit commitment process.[17/] According to the CAISO, one purpose of the initiative "is to ensure that RA imports are backed by physical capacity and reserves with firm transmission delivery."[18/]

The CAISO has issued three straw proposals and conducted several workshops. It also has solicited written comment from stakeholders. The Third Revised Straw Proposal proposes to require that RA imports specify the source balancing area.[19/] In addition, the CAISO proposes to conform the CAISO Tariff to existing CPUC requirements:

> Therefore, the CAISO proposes that all LSEs must submit supporting documentation that any non-specified RA import resource shown on annual and monthly RA and Supply plans have firm energy delivery. Similar to the CPUC requirements, the supporting documentation that the CAISO will require can be in the form of contract language or an attestation from the import provider that confirms the import is supported by firm energy and operating reserves.[20/]

17/ Resource Adequacy Enhancements Issue Paper at 8 (Oct. 22, 2018); http://www.caiso.com/InitiativeDocuments/IssuePaper-ResourceAdequacyEnhancements.pdf

18/ Resource Adequacy Enhancements Third Revised Straw Proposal at 51(December 20, 2019); http://www.caiso.com/InitiativeDocuments/ThirdRevisedStrawProposal-ResourceAdequacyEnhancements.pdf

19/ Id. at 51.

20/ Id. at 54.

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The CAISO also has stated that it is open to considering resource-specific requirements for RA imports; however, it is not currently proposing such requirements.[21/] The CAISO is expected to release the Fourth Revised Straw Proposal on March 16, 2020; and, a stakeholder meeting to discuss the proposal has been set for March 24, 2020. The CAISO expects to take a final proposal to its Board later this year.

c. POLR obligations

California has no law specifying that the incumbent utility must act as the provider of last resort for direct access customers. Instead, this obligation has been inferred from the Public Utility Code's general mandates to furnish adequate, just and reasonable, and nondiscriminatory service.[22/] The CPUC allows direct access customers to switch between direct access and cost-of-service, subject to certain notice provisions and minimum stay requirements. Specifically, direct access customers must provide six months' notice to return to cost-of-service and must remain on cost-of-service for a minimum of 18 months.[23/]

Large customers that return to cost-of-service on an emergency basis are required to pay the Temporary Bundled Service ("TBS") rate, which is a market-based rate, with similar components to the PCIA, that is designed to ensure these customers pay all costs associated with their return to bundled service.

d. Lessons

The CPUC has undoubtedly put substantial work into the development of its direct access and other customer choice programs. Nevertheless, despite this effort, it is unclear

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21/ Id. at 53.
22/ California Customer Choice Project, "Choice Action Plan and Gap Analysis" at 33 (Dec. 2018).
23/ CPUC Docket No. R.07-05-025, Dec. No. 11-12-018 at 46, 51 (Dec. 7, 2011).

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that the State has made material progress toward creating workable direct access programs and resolving disputes among stakeholders. In fact, California's experience suggests that the deeper the CPUC has gone into the weeds of direct access issues, the more controversial its decisions and these programs have become. With more issues on the table, there are more issues for parties to fight over. This not only yields questionable value, but would absorb a substantial amount of Commission resources if it attempted the same level of granularity as the CPUC. If, like the CPUC, the Commission finds itself issuing 50-page orders on a true-up mechanism for transition adjustment charges, then it will either need to substantially increase its budget and staff, or it will need to divert resources from other, potentially more important, issues. It would be ironic if direct access – the one mechanism some customers have to remove themselves from most rates subject to Commission regulation – ended up taking more of the Commission's time than actual rate regulation.

The amount of effort the CPUC has spent on direct access issues is also impacted by State-specific requirements. For instance, the existence of CCAs creates a heightened need for the CPUC to establish strong consumer protections, which can themselves be controversial. By limiting long-term direct access to large, sophisticated customers, Oregon and other states have avoided the need to establish similar regulations.

The existence of CCAs in California also complicates POLR issues because there is a heightened need to ensure default service for CCA customers. Unlike large customers on direct access, CCA customers include residential and small commercial customers that have limited, if any, influence over the CCA's resource acquisitions and contract negotiations and are, therefore, fully exposed if the CCA or its supplier defaults. These customers are also generally

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less sophisticated about their energy usage and options and, consequently, are less equipped to address problems with their energy supply.

Unlike in California, Oregon does have some POLR provisions in its direct access law, though these provisions are flexible in some interesting ways. ORS 757.603(1) requires electric companies to provide a cost-of-service rate option to every customer. However, subsection (2) of this statute authorizes the Commission to waive this requirement for any customer other than residential and small commercial customers under certain circumstances enumerated in the statute. Additionally, ORS 757.622 requires the Commission to "establish the terms and conditions for providing default electricity service for nonresidential electricity consumers in an emergency." The direct access law does not, however, specify that the distribution utility (i.e, PGE or PacifiCorp) must provide this default service, and the Commission has the discretion to determine what terms and conditions should apply to the provision of default service.

Differences between California and Oregon law also potentially impact how cost-shifting from direct access is considered and addressed. The CPUC has interpreted its statutes preventing "any cost increases" as a result of direct access to mean that "the requirement to equitably allocate the cost of [resources] among bundled service customers and departing load customers is manifest and absolute, and applies for as long as procurement costs incurred … on behalf of departing load customers continue to exist."[24/] Thus, the PCIA now continues indefinitely for direct access customers, and an annual true-up applies to reconcile differences between actual and forecasted costs to prevent "any cost increases" whatsoever from direct

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[24/] Dec. No. 18-10-019 at 54 (quoting opening brief of PG&E, SDG&E, and SCE at 29).

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access participation. Oregon's direct access law, by contrast, prohibits "the unwarranted shifting of costs" from direct access participation.[25] The Commission has yet to interpret what "unwarranted" means, but this term plainly implies that some cost-shifting may be warranted. AWEC intends to address this issue in Phase 2 of this proceeding. For now it is enough to note that the difference between the California and Oregon statutory language governing cost shifting from direct access provides a basis for the Commission to address cost-shifting differently than the CPUC has.

Finally, as noted above, one component of the PCIA is an adder for capacity/resource adequacy. This adder exists because all load-serving entities (including direct access suppliers) have resource adequacy obligations under California law, and this resource adequacy is bought and sold between load-serving entities to meet this obligation. Thus, there is a market value in California for resource adequacy. Without a similar market in Oregon, if the Commission is to consider valuing capacity as a component of a transition charge, it will need to identify how to determine this value.

Also with respect to resource adequacy, the CPUC's and CAISO's processes to review and potentially revise their resource adequacy requirements may be instructive for Oregon, particularly as it investigates the ability of market products, like firm liquidated damages contracts, to provide resource adequacy.

2. Nevada

Chapter 704B of the Nevada Revised Statutes ("NRS") allows an eligible customer that has an annual load of 1 MW or more to file an application with the Public Utility

[25] ORS 757.607(1).

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Commission of Nevada ("PUCN") to purchase energy, capacity or ancillary services from a provider of "new electric resources."[26] Approximately 13% of NV Energy's load is distribution-only service.[27] Prior to 2019, Chapter 704B required the PUCN to approve an application unless it found that it would be contrary to the public interest.[28] In determining this public interest test, the PUCN evaluated "whether the electric utility that has been providing electric service to the eligible customer will be burdened by increased costs as a result of the proposed transaction or whether any remaining customer of the electric utility will pay increased costs for electric service as a result of the proposed transaction."[29] The law also allowed the PUCN to impose such "terms, conditions and payments as the Commission deems necessary and appropriate to ensure that the proposed transaction will not be contrary to the public interest."[30]

While many of these provisions continue in effect, the Nevada Legislature substantially amended NRS Chapter 704B in 2019.[31] Some of these changes are mentioned below, but the full impact of these changes remains subject to ongoing rulemakings. Thus, these comments focus primarily on how NRS Chapter 704B was implemented and interpreted prior to the 2019 amendments.

a. Individual application process

Unlike Oregon, Chapter 704B requires customers to apply for the program individually. In Oregon, transition adjustment charges are set annually in PGE's and

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[26] NRS 704B.300; 080.
[27] Based on workpapers from Nevada Power's 2017 general rate case and Sierra Pacific Power's 2019 general rate case.
[28] A.B. 661§20(5)(A) (2001).
[29] Id. at 6(A).
[30] Id. at 7(B).
[31] Senate Bill 547 (2019)

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PacifiCorp's power cost updates (the AUT and TAM, respectively), and customers are allowed to transition to direct access during open enrollment windows. Nevada's individual application process has resulted in each 704B customer's impact on the system being evaluated separately.

Individual applications carried the benefit of allowing the PUCN to assess each exiting customer's impact on the system. It also, however, resulted in some negative unintended consequences. Certain customers felt that they were being treated disparately and unfairly. In 2014, Switch, Ltd. ("Switch") became the first customer to apply under NRS Chapter 704B in a decade, and its application was denied outright.[32/] Only a few months later, though, the PUCN approved the 704B applications of three individual hotel and casino operators.[33/] Switch complained about this disparate treatment, sued the PUCN, and also filed a second application.[34/] This second application was ultimately approved through a settlement agreement, with Switch agreeing to pay an impact fee of $27 million.

Meanwhile, the impact fees the PUCN approved for the casinos that had applied were also substantial – over $15 million for Wynn Las Vegas, nearly $24 million for Las Vegas Sands, and nearly $87 million for MGM Resorts International. The PUCN also required these

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32/ Docket No. 14-11007, In the Matter of the Application of Switch Ltd., for Leave to Exit the System of Nevada Power Company d/b/a NV Energy in Accordance with the Provisions of NRS Chapter 704B and NAC Chapter 704B (Nov. 7, 2014).

33/ Docket No. 15-05017, Application of MGM Resorts International to purchase energy, capacity, and/or ancillary services from a provider of new electric resources in accordance with the Provision of NRS Chapter 704B and NAC Chapter 704B (May 12, 2015); Docket No. 15-05006, In the Matter of the Application of Wynn Las Vegas, LLC for Leave to Exit the System of Nevada Power Company, d/b/a NV Energy, in Accordance with the Provisions of NRS and NAC Chapter 704B (May 4, 2015); Docket No. 15-05002, In the Matter of the Application of Las Vegas Sands Corp. for Leave to Exit the System of Nevada Power Company, d/b/a NV Energy, in Accordance with the Provisions of NRS and NAC Chapter 704B (May 1, 2015).

34/ See Switch, Ltd. v. Nevada Power, et al., Case No. 2:16-cv-01629-JCM-CWH (Dist. Ct. Nev. 2016); Docket No. 16-09023, Application of Switch, Ltd. to Purchase Energy, Capacity, and/or Ancillary Services from a Provider of New Electric Resources, Order (Dec. 28, 2016).

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customers to pay a number of nonbypassable charges in addition to their impact fees. These nonbypassable charges included: (1) costs associated with legislatively mandated above-market renewable energy costs on the basis that these costs would continue to be incurred beyond the period used to determine the impact fee;[35/] and (2) costs associated with legislative mandates to reduce Nevada Power's reliance on coal-fired power, including unrecovered investments and decommissioning costs.[36/] While Wynn and MGM ultimately agreed to these terms, Sands withdrew its application.

The impression that customers applying under Chapter 704B were being treated unfairly (either because their applications were denied outright or because they were required to pay massive impact fees, or both) played a material part in the advancement of the Energy Choice Initiative, also known as Ballot Question 3.[37/] Question 3 would have amended the State constitution to require full retail access, down to the residential customer level. Question 3 ultimately failed in 2018 following one of the most expensive ballot campaigns in Nevada's history.[38/]

Despite these controversies, the PUCN began seeing numerous applications under Chapter 704B, which absorbed much of the PUCN's time and attention. Between 2015 and 2019, nearly twenty other casino customers, industrial customers, entertainment venues and related large energy users filed 704B applications. A few of these applications were filed by new

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35/ Docket No. 15-05017, Order ¶¶ 189-94, 200-02 (Dec. 13, 2015); Docket No. 15-05006, Order ¶¶ 253-58, 264-66 (Dec. 3, 2015).

36/ Docket No. 15-05017, Order ¶¶ 206-10 (Dec. 13, 2015); Docket No. 15-05006, Order ¶¶ 270-74 (Dec. 3, 2015).

37/ Both Switch and Sands were major contributors to Question 3.

38/ James DeHaven, About $63 million was spent to defeat Nevada's Question 3. It worked, November 6, 2018, available at: https://www.rgj.com/story/news/politics/2018/11/06/63-million-spent-defeat-nevadas-question-3-worked/1908835002/ (last accessed March16, 2020).

customers based on an advisory opinion the PUCN provided to Google in 2017, in which it concluded that, similar in concept to the Commission's New Load Direct Access Rules, new customers that the utility had not planned for need not pay any impact fee if they apply to go straight to the market.[39/]

In response to these applications, Nevada Power began negotiating with these customers in an effort to keep them on bundled service. These negotiations ultimately led to the development of a new Market Price Energy rate schedule, which allows Nevada Power to serve eligible customers with a market-based rate.[40/] The PUCN approved this tariff on January 30, 2020.[41/] This tariff is applicable to nonresidential customers with annual loads of at least 1 MW and who have been approved by the PUCN to participate in the 704B program without paying an impact fee, but have not yet begun taking service from a third party under that program.[42/] The Market Price Energy tariff, in other words, is a direct attempt by Nevada Power to compete with third-party suppliers. Allegiant Stadium, the 2020 home of the Las Vegas Raiders, was the first customer approved to take service under this tariff.[43/]

In response to the number of 704B applications and the controversies surrounding Question 3, the Nevada Legislature amended Chapter 704B in 2019. The amendments included the following: (1) Requiring regulated utilities to propose, and the PUCN to approve, annual limits on the total amount of energy/capacity that eligible 704B customers can purchase from providers of new electric resources; (2) Requiring state licensure for providers of new electric

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39/ See Docket 17-04019, Advisory Opinion to Google on NRS Chapter 704B (Sep. 8, 2017).
40/ Docket No. 19-10011.
41/ Id., Order (Jan. 30, 2020).
42/ Id. ¶ 2.
43/ Docket No. 19-10012, Order (Jan. 30, 2020).

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resources; (3) Ensuring that various "public program costs" furthered by the State are funded in-kind by 704B customers; and (4) Limiting the application period to the month of January each year, and prohibiting the 704B customer from taking service earlier than 280 days from the application filing date.[44] Rulemakings at the PUCN to implement these amendments remain ongoing.[45]

b. Resource adequacy requirements

Chapter 704B also contains provisions to address resource adequacy. The law refers to direct access suppliers as "providers of new electric resources." This provision was in direct response to the California Energy Crisis. The Nevada Legislature had previously directed the State to deregulate its energy markets,[46] but the Energy Crisis forced the State to put this process on hold. The crisis exposed how reliant Nevada was on western power markets. To address this issue, the State repealed full deregulation in favor of partial deregulation for large customers and required any such customer exiting the incumbent utility to bring new electric resources to the State. Specifically, prior to 2019, NRS 704B.110 required a 704B customer to acquire energy, capacity, or ancillary services "made available from a generation asset that is not owned by an electric utility or is not subject to contractual commitments to an electric utility" and to contract for an additional 10% above the customer's load and make it available to the utility.

When MGM Resorts International applied under Chapter 704B, the PUCN initially determined that it lacked sufficient information on whether MGM would comply with

[44] S.B. 547 (2019).
[45] PUCN Docket 19-06029.
[46] A.B. 366 (NV Legislative Session 1997).

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these requirements of NRS 704B.110 because MGM had committed to take service from a third party pursuant to Schedule C of the Western Systems Power Pool ("WSPP") Agreement, which provides for firm market purchases.[47/] Since Nevada Power sells the output from its resources into the market, the PUCN determined that it could not ensure that MGM would source energy from a "specific new electric resource" and that its market purchases would not include purchases from Nevada Power resources.[48/]

On reconsideration, however, the PUCN reversed this decision. It found that "power obtained through market resources that are not directly sourced from a Nevada Power generation asset qualifies as a new electric resource under NRS 704B.110."[49/] This is because, "if Nevada Power sells power into the market, that power is no longer considered to be unavailable for purchase, which means that it is available for purchase by an eligible customer, such as MGM."[50/] The PUCN made similar findings with respect to Wynn, and agreed with that customer that, even if Wynn "were to build a power generation asset adjacent to its facilities in order to serve its load, market purchases would still be necessary to manage the load and procure power during times the generation asset is unavailable or not meeting the load requirements."[51/] Thus, "requiring Wynn to specify each generation asset that would be required to service its departing load would require Wynn to also ensure that it specifies a standby asset that would be

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47/ Docket No. 15-05017, Application of MGM Resorts International to purchase energy, capacity, and/or ancillary services from a provider of new electric resources in accordance with the Provision of NRS Chapter 704B and NAC Chapter 704B Order ¶ 147 (Dec. 13, 2015);

48/ Id.

49/ Docket No. 15-05017, Order ¶ 20 (Jan. 20, 2016).

50/ Id.

51/ Docket No. 15-05006, In the matter of the Application of Wynn Las Vegas, LLC for Leave to Exit the System of Nevada Power Company, d/b/a NV Energy, in Accordance with the Provisions of NRS and NAC Chapter 704B, Order ¶¶ 33-34 (Jan. 20, 2016).

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utilized to mitigate any future energy imbalances …"[52] The PUCN found that such a requirement "effectively places an undue burden on Wynn."[53] The 2019 amendments modified NRS 704B.110 to clarify that market purchases qualify as a "new electric resource" and eliminated the 10% contract requirement.[54] Mr. Wellinghoff provides further discussion of resource adequacy in Nevada.

c. Lessons

There is intuitive appeal to Nevada's requirement that each customer file an application to participate in the 704B program, as it allows the PUCN to assess each exiting customer's specific impact on the system. The downsides of this process, however, have likely outweighed the benefits. Preparing an application and participating in the regulatory process is costly, and it exposes customers to public scrutiny. Only a small subset of eligible customers are willing to incur this cost and engage in the process; thus, a large portion of otherwise eligible customers are deterred from participating. Processing exit applications is also time- and resource-intensive for the Commission. Finally, customers can be dissatisfied with the decisions on their applications, either due to the exit fee they must pay, or other conditions on their departure, which a standardized process avoids. Other interest groups may also attempt to intervene in these processes and argue for additional concessions from the exiting customer. If the process is perceived to be inequitable or opaque, it may engender calls to reform it, which in Nevada became as drastic as a proposed constitutional amendment in Ballot Question 3.

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[52] Id. ¶ 34.
[53] Id.
[54] NRS 704B.110(2).

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With respect to nonbypassable charges, the PUCN primarily imposed such charges when they were the result of legislative requirements that created exceptions to least-cost/least-risk planning. Notably, however, the only nonbypassable charges the PUCN imposed were those that had been incurred, or were required to be incurred, when the exiting customer took bundled service; the PUCN did not leave open the possibility for exiting customers to bear nonbypassable charges that may be created in the future.

Finally, the PUCN's approval of Nevada Power's Market Price Energy tariff provides an example of how the incumbent utility could compete for load that would otherwise go to direct access. Because this tariff was approved so recently, it is likely too early to tell whether such competition will contribute to or impede the development of a competitive market in Nevada.

3. Washington

a. Limited direct access programs

Washington is unique among the states considered in these Opening Comments in that it has no direct access law, and yet has direct access customers. All such customers are confined to Puget Sound Energy's ("Puget") service territory and exist because of agreements made between these customers and Puget.

The first agreement resolved a complaint at the Washington Utilities and Transportation Commission ("WUTC") that several large customers brought against Puget during the Energy Crisis, alleging that Puget charged them unjust and unreasonable rates.[55] To

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[55] Air Liquide America Corp. v. Puget Sound Energy, WUTC Docket Nos. UE-001952/UE-001959, 11th Supp. Order (Apr. 5, 2001).

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settle the complaint, Puget agreed to create a new tariff, Schedule 449, that allowed these customers to purchase their electricity from a third party.[56] Schedule 449 is available to a closed class – it is restricted specifically to the locations owned by the customers that entered into the settlement agreement creating this tariff (subject to limited exceptions). The second agreement is the Special Contract Puget negotiated with Microsoft Corp. in 2016-2017, also allowing Microsoft to purchase from a third party. In total, these customers represent approximately 10% of Puget's electric delivery load.[57]

b. POLR obligations

Several differences exist between direct access in Washington and Oregon. Unlike in Oregon, where direct access is available to all nonresidential customers (and for long-term direct access currently, all customers over 1 aMW), in Washington direct access is limited to the specific customers Puget has allowed to leave bundled service. Further, in Oregon, the electricity service supplier must be the transmission customer for purposes of receiving service under PGE's or PacifiCorp's Open Access Transmission Tariff ("OATT"), whereas the customer itself can be the transmission customer under Puget's OATT.

Finally, while customers on long-term direct access in Oregon can return to bundled service with sufficient notice, the 449 customers and Microsoft are never allowed to return to bundled service under any circumstance.[58] In other words, Puget has relinquished its provider of last resort obligations for these customers. That does not, however, mean that Puget

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56/ PSE also created Schedule 448 pursuant to the stipulation, which allows PSE to purchase market power for customers served under the tariff; however, no customer takes service under Schedule 448.

57/ WUTC v. Puget Sound Energy, WUTC Docket Nos. UE-191529 et al., Exh. JAP-14 (showing total delivery sales of 22,868,255 MWh and delivery sales for retail wheeling customers of 2,364,948 MWh).

58/ Puget Schedule 449 § 14.2; Microsoft Special Contract § 14.1.

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will not serve these customers under any circumstance. In the event a direct access customer's supplier fails to deliver, Schedule 449 and Microsoft's Special Contract specify that Puget "has no obligation to replace such Energy using its own generation resources, but shall make commercially reasonable efforts to obtain in the market replacement Energy for such delivery failure."[59/]

Despite being forever bound to the market, these customers remain subject to Puget's standard curtailment procedures, including during times of "lack of sufficient generating capacity" and during "times of anticipated deficiency of resources."[60/] To AWEC's knowledge, neither PSE nor any other entity has ever raised concerns about the applicability of these curtailment protocols to the 449 customers or Microsoft.

c. Compliance obligations

Both because Washington has no direct access law and because Puget's direct access customers have no provider of last resort, these customers have been exempted from most energy-related legislation passed in the State. For instance, Washington's Clean Energy Transformation Act ("CETA"), passed in 2019, which requires each utility in the State (both investor- and consumer-owned) to be carbon-neutral by 2030 and carbon-free by 2045, exempts existing "market customers."[61/] Washington's Energy Independence Act (the State's renewable portfolio standard), however, does require that each utility acquire "all cost-effective conservation," and both Microsoft and the 449 customers participate in Puget's energy efficiency

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59/ Puget Schedule 449 § 2.5; Microsoft Special Contract § 4.5.

60/ Puget Schedule 80 §12(a), (d).

61/ RCW 19.405.020(26)(a), 19.405.040(1). Customers that become "market customers" after CETA's passage, however, are required to comply with the law. RCW 19.405.020(26)(b), 19.405.040(9).

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programs as a result.[62] This participation comes primarily through a conservation self-direct program Puget runs pursuant to its Schedule 258.

Differences also exist between the 449 customers and Microsoft. The 449 customers largely operate independently of state regulation – their distribution costs are directly assigned (but still established through a WUTC-jurisdictional rate proceeding) and all other costs are either unregulated or subject to FERC jurisdiction. Microsoft, however, made several commitments in exchange for becoming a direct access customer, including renewable energy, low income, and energy efficiency commitments, that require the company (through Puget) to report its compliance to the WUTC. Microsoft, for instance, files annual reports, similar to the utilities, on its compliance with its renewable energy commitments.

d. Lessons

Removal of Puget's provider of last resort obligation has simplified WUTC regulation of Puget with respect to its direct access customers. For instance, resource adequacy concerns, if not entirely eliminated, are at least greatly diminished because the direct access customer effectively takes on the risk of a lack of resource adequacy to serve its load. If a direct access customer's resources are not available or its supplier defaults, Puget will make "commercially reasonable efforts" to step in and provide backup supply, but it has no *obligation* to provide this supply. It also addresses concerns regarding cost-impacts from a customer returning to cost-of-service because that customer cannot return to cost-of-service.

The limitation of direct access to a few large customers also eliminates the need for the WUTC to implement and oversee consumer protections. These customers are sufficiently

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[62] RCW 19.285.040(1).

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sophisticated to look out for their own interests and protect themselves through the contracting process with their energy supplier.

4. Arizona

Article 15 of the Arizona Constitution establishes a Corporation Commission ("ACC") composed of 5 elected Commissioners. Retail competition in Arizona is subject to the ACC's jurisdiction, which is governed by both Arizona statutes and the Arizona Constitution. The Arizona Constitution gives the ACC exclusive jurisdiction regarding utility rates, which cannot be changed by the Legislature. However, the Legislature is authorized to grant additional powers to the ACC, if they do not conflict with the Arizona Constitution.

The ACC is currently investigating the implementation of retail electric competition for all electric users in the state of Arizona in Docket No. RE-00000A-18-0405. The future process in that docket is not well defined; and, it remains uncertain whether any retail competition will be allowed in Arizona.

a. Background

The ACC first began investigating retail electric competition in Arizona in 1994. In December 1996, the ACC adopted rules ("Competition Rules") to establish a competitive system for retail electric supply.[63/] After multiple revisions of the rules in 1998 and 1999, the ACC approved approximately 20 Certificates of Convenience and Necessity ("CC&Ns") for entities to provide competitive electric service in Arizona. Some retail electric competition occurred in 1999 and 2000.[64/] The current version of the Competition Rules was adopted by the

[63/] Arizona Administrative Code ("A.A.C.") R14-2-1601 to R14-2-1616.
[64/] Staff Report, dated July 1, 2019 (Docket No. RE-00000A-18-0405).

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ACC in Decision No. 62924 (October 10, 2000). Retail electric competition came to a halt when competitive suppliers returned all their customers to the affected or incumbent utilities following problems in the wholesale market related to the 2001 energy crisis.[65/] In 2004, in Phelps Dodge Corp. v. Arizona Elec. Power Co-Op., Inc., the Arizona Court of Appeals invalidated a number of provisions in the Competition Rules and all of the CC&Ns that had been granted for competitive electric service.[66/]

Following the 2001 energy crisis and the Phelps Dodge decision, retail competition in Arizona was effectively terminated. In the ensuing decade, one energy marketer attempted to obtain a CC&N, but that request was denied. In 2013, the Commission revisited the issue of retail electric competition, but took no formal action. In August 2018, the Commission again examined the possibility of making modifications to Commission energy rules, including retail electric competition, which led to the opening of a rulemaking docket on December 19, 2018.[67/]

b. Phelps Dodge Decision

If the ACC does allow competition, it must do so in compliance with very specific statutory and Constitutional boundaries, as they have been interpreted by Arizona courts, particularly in Phelps Dodge. As a result, Arizona retail electric competition, if adopted, will likely not create a good model for other states.

Phelps Dodge was a consolidated case in which the Arizona Court of Appeals was asked to resolve various constitutional, statutory, and administrative challenges to the

65/ Id.
66/ Phelps Dodge Corp. v. Arizona Elec. Power Co-Op., Inc., 83 P.3d 573 (Ariz. Ct. App. 2004).
67/ Docket No. RE-00000A-18-0405.

Competition Rules promulgated by the Commission to implement competition. In particular, the petitioners alleged that the ACC's Competition Rules were unconstitutional and the CC&Ns for energy service suppliers were invalid.

Section 3 of Article 15 provides that the Commission shall set "just and reasonable rates;" and, Section 14 of Article 15 requires that the "fair value" of in-state property owned by every public service company be used to set just and reasonable rates. Based on these provisions, the Court invalidated every CC&N for energy service suppliers, because the ACC did not use fair value to determine whether their rates were just and reasonable.[68/] The Court also invalidated a portion of the rules that stated that "market determined rates . . . . shall be deemed just and reasonable." The Court stated that the Commission has discretion to set rates as long as it at least considers "fair value." In addition, it stated that the Commission could establish a range of rates and allow market forces to set specific rates within the range.[69/]

The Court also invalidated rules requiring utilities to divest generation and form an independent system operator on the grounds that the rules were beyond any ACC authority granted by statute or the Arizona Constitution.[70/] Finally, the Court invalidated portions of the rules on the grounds that they were not properly approved by the Arizona Attorney General.[71/] Any competitive retail electric model implemented in Arizona will need to comply with the requirements imposed by Phelps Dodge.

[68/] Phelps Dodge Corp. v. Arizona Elec. Power Co-Op., Inc., 83 P.3d at 583.
[69/] Id. at 587.
[70/] Id. at 590-592.
[71/] Id. at 594.

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c. Current Rulemaking

On December 19, 2018, pursuant to a Commission directive, ACC Staff opened a rulemaking docket to consider possible modifications to the Competition Rules. In addition, the Commission directed ACC Staff to review the Commission's current rules and modify them to best suit Arizona while taking into consideration feedback from stakeholders. Both the ACC Staff and various Commissioners have filed proposed rules in the rulemaking. The ACC held stakeholder workshops attended by the Commissioners on July 30-31, 2019, December 3, 2019, and February 25-26, 2020. Numerous parties have participated in the workshops and filed written comments. These include investor-owned utilities, cooperatives, municipalities, unions, representatives of retail energy suppliers, AARP, community choice advocates, and the Residential Utility Consumer Office. Some parties are strong advocates of moving to full retail choice, while others raise questions or are adamantly opposed to the proposal. The ACC Staff has participated in the process, mainly by providing information related to retail choice in other states.[72/]

The comments filed in the proceeding, as well as the presentations at workshops, have addressed a wide variety of topics related to retail access, including the role of utilities in a competitive market, the regulation of energy service providers, the need for an independent system operator, the treatment of stranded costs, the determination of a default provider, the role of community choice associations and the impact of the Phelps Dodge case on a competitive model. Two Commissioners have filed competing sets of rules, which do not appear to have the

72/ A report by ACC Staff providing the results of its research is available here: https://docket.images.azcc.gov/E000003492.pdf.

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support of the other three Commissioners. At this point, it is unclear whether retail competition will be reimplemented in Arizona, or what the future process will be in the rulemaking docket. The Commissioners do not seem to be in agreement on either issue. It is likely that further workshops will be held to explore the many issues that have been raised in more detail.

III. CONCLUSION

AWEC appreciates the opportunity to provide comments on the issues identified for Phase 1 of this proceeding and looks forward to working with the Commission and the parties to this docket.

Dated this 16th day of March, 2020.

Respectfully submitted,

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March 16, 2020

Public Utility Commission of Oregon
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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

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

I. INTRODUCTION

I appreciate the opportunity to provide opening comments to the Oregon Public Utility Commission ("OPUC" or "Commission") on behalf of the Alliance of Western Energy Consumers ("AWEC") on 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 the Administrative Law Judge.[1] Pursuant to that Staff proposal, the parties recommended and the Administrative Law Judge ruled that in Phase 1 of this proceeding there be simultaneous initial comments filed discussing certain policy issues relevant to long-term direct access. My comments address the potential benefits and costs of long-term direct access programs and resource adequacy issues.

[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

Q1. What are the potential benefits and potential costs to customers from long-term direct access participation?

A1. Since Oregon's electric utility restructuring law went into effect in March of 2002, large and small business customers have been able to have direct access to choose an alternative Electricity Service Supplier ("ESS").[2] Under that law the Commission has authorized through rules and tariff approvals of tariff filings a number of long-term direct access ("LTDA") programs for eligible business customers in Oregon.[3] These LTDA programs do provide demonstrable benefits to all current and future customers of Oregon's jurisdictional utilities, both to those customers who are eligible for and participants in the direct access programs and to those remaining monopoly utility customers who either choose not to or do not qualify for direct access participation.

Benefits

Direct access has the potential to provide business customers in Oregon with meaningful options to lower energy costs through competitive energy service plans from multiple service providers where those businesses can decide which option best meets their needs and lowers their bills. This is a direct benefit to them. Certainly, sophisticated businesses and industries

[2] ORS 757.600 *to* 757.691
[3] Pursuant to statute the OPUC has authorized direct access programs for both existing load business customers and new load business customers. Each jurisdictional utility has filed tariffs to implement those programs with variants on program design. Except where otherwise indicated, the term LTDA is used in these comments to apply to both existing load direct access program participants and new load direct access program participants.

should be given the opportunity to decide for themselves if long-term direct access will provide benefits and value to their enterprise.

And it should be understood that the benefits to these businesses from LTDA program participation is not simply the potential to lower rates through buying less expensive market rate resources such as energy, capacity and ancillary services, or to contract for a specific resource or energy mix to meet corporate goals. Direct access provides businesses the opportunity to sell market services as well. As participants in the market in the Western Interconnect overseen by the Western Electricity Coordinating Council[4] ("WECC"), Oregon LTDA customers have the opportunity to sell electric resource products to both the Energy Imbalance Market ("EIM") which is operated by the California Independent System Operator ("CAISO") and to the CAISO market itself. These revenue opportunities open to Oregon LTDA customers can provide further means for those customers to lower their total energy bills and enhance benefits to themselves, other Oregon customers, and further state policies.

There is also the benefit to all Oregonians, LTDA participants and non-participants, from the economic development potential of attracting new businesses and industries to Oregon because of access to market-based low electric rates. A recent industry report indicates that new businesses are attracted to a state by access to low cost renewable energy. Oregon was ranked

[4] The WECC is a not-for-profit organization that works to effectively and efficiently mitigate risks to the reliability and security of the Western Interconnection's Bulk Electric System (BES). WECC operates under a Federal Energy Regulatory Commission ("FERC") approved delegation agreement with the North American Electric Reliability Corporation ("NERC") and in accordance with WECC's Bylaws.

16th in that report's clean energy state procurement index.[5] Greater access to market-based low cost clean energy for industries looking to relocate could help Oregon achieve a higher ranking and attract more business development. That would be a benefit for everyone in Oregon.

To the extent that Oregon businesses find value in participating in a LTDA program and are able to lower their internal energy costs from such access, there are two additional potential benefits to everyone in Oregon. First, by lowering the cost of doing business for existing business customers, more firms will decide to stay in Oregon contributing to a vibrant economy. Second, if business costs are lower, some portion of those lower costs may be passed on to Oregon consumers in the form of lower-cost goods and services – an additional benefit to all.

The question then becomes: Does long-term direct access provide other more direct benefits to customer ratepayers who are ineligible or choose not to participate in the LTDA programs? A Commission Staff report incorporated into the Commission's Order No. 18-031 in Docket Nos. AR 614 and UM 1837 outlined a number of potential benefits from LTDA programs.[6] The benefits listed in that report included:

- Economies of scale for utility administrative and distribution costs;
- Reduce utility load growth and need to add generation resources or replace coal resources;

[5] *Corporate Clean Energy Procurement Index: State Leadership Rankings*, RILA/ITI Clean Edge, January 2017.
[6] PUBLIC UTILITY COMMISSION OF OREGON, STAFF REPORT, Docket Nos. AR 614 & UM 1837, Order No. 18-031, Appendix A, p. 4 of 10, January 19, 2018. The report focused on the New Load Direct Access program, but the benefits are potentially applicable to all LTDA program customers.

- Reduce future average system cost by avoiding new resources;
- Reduce average system cost by sharing option value of New Load Direct Access ("NLDA") with cost of service ("COS") customers;
- Develop the competitive generation market; and
- Increase efficiency of regulated generation through competitive pressure.

While the above list was intended by Staff to represent potential customer benefits created for COS customers by NLDA customer participation, some of the list is applicable to any LTDA participation as well.

The first Staff benefit, economies of scale for utility administrative and distribution costs, is applicable to primarily NLDA participation. To the extent that customers elect to participate in the NLDA programs, and those new loads attract additional employees and supporting businesses, the cost burdens on the utilities and thus their customers for administrative and distribution costs will be reduced.

The second enumerated benefit, reduced utility load growth and need to add generation resources or replace coal resources, is an obvious benefit to existing COS customers for resources the utility has yet to expend dollars to acquire or build for NLDA customers. But a similar benefit argument can be made even for existing load LTDA customers to the extent their load is replaced with new load growth from new COS customers and the resources serving the LTDA customer prior to their exiting the system become fully depreciated. Their exit from the system frees up resources to serve new COS load or allows old (coal) resources to be retired without their full capacity needing to be replaced. Thus, there are benefits from LTDA participation by both new and existing loads.

The next Staff benefit, reduce future average system cost by avoiding new resources, again is a benefit whether the LTDA participant comes from new or existing load. In either case new resources are avoided and future average system costs are reduced. Clearly this is a benefit to COS customers. This is a particularly valuable benefit to COS customers today with the rapid retirement of coal-fired capacity that will otherwise need to be fully replaced absent the departure of load to LTDA programs.

Staff next indicates a benefit from reduce average system cost by sharing option value of NLDA with COS customers. The option value that NLDA customer contracts will bring to the balancing areas within Oregon are a benefit to COS customers, as stated by Staff. But that option value similarly holds true for existing load LTDA contracts. This is the case as long as the Commission ensures that the market contracts entered into by LTDA participants do not commit resources that are committed to existing loads in the Oregon balancing areas.

The opportunity for LTDA programs to contribute to development of a competitive generation market in Oregon is another Staff listed benefit and should not be overlooked by the Commission. Literally from Walmart to Google,[7] ever increasing numbers of major businesses are actively pursuing low cost clean renewable generation often not available from their monopoly COS utility. Viable and robust LTDA programs in Oregon for both existing loads and new loads will encourage development of wind and solar resources targeted to serve those loads.

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[7] *From Walmart to Google, Companies Teaming Up To Buy More Solar and Wind Power*, Camila Domonoske, NPR Business, March 28, 2019.

This fosters a competitive generation market in Oregon such as has been created in Nevada and other states.

Finally, as Staff indicated, regulated COS generation will be forced to become more efficient through competitive pressure from the institution of LTDA programs. This has been demonstrated in Nevada, where large customer retail access has been available since 1999.[8] In the last several years, competitive pressures from both lower Western market prices and lower costs of large-scale solar development have required the incumbent utility, NV Energy, to become more cost competitive to compete for customers seeking to exit the system. This competition has driven NV Energy to commit to build 1.2 GW of new solar and 2.3 GWh of storage at competitive prices to offer to potential exiting customers.[9] Similar benefits could be realized by Oregon customers from an effective suite of LTDA programs.

Costs

The Commission Staff also posited in its report in Order 18-031 a list of potential costs from a NLDA program. Those were:

- Stranded generation costs;
- Administration and oversight of NLDA program;
- Additional planning and forecasting complexity;
- Foregone economies of scale in generation during periods of resource adequacy;

[8] NRS 704B.
[9] *NV Energy to add 1.2 GW solar, 2.3 GWh storage as large customer exit slows*, Catherine Morehouse, Utility Dive, June 25, 2019.

- Increased load uncertainty; and
- Customers in existing facilities may operate at higher costs than customers at new facilities.

In reviewing these potential costs from both the perspective of a NLDA program and programs for existing load LTDA customers, none individually or even collectively would appear to outweigh the comprehensive and substantial benefits discussed previously.

First, the last of the potential costs, customers in existing facilities operating at higher costs than customers at new facilities, could prove to be a benefit. To the extent that customers in facilities that take advantage of LTDA programs experience lower energy costs than customers who do not do so, more customers will be driven to LTDA programs to remain competitive and more benefits will accrue to Oregon customers.

With respect to existing load customers, potential stranded cost issues are readily solved with the development and levying of appropriate transition adjustment or exit fees. This is currently done for existing LTDA customers, and AWEC will address the effectiveness of the current transition adjustment methodology in Phase 3 of this proceeding.

Planning, forecasting and load balancing issues are minor administrative and operational issues that certainly cannot impose costs sufficient to offset the substantial benefits that could accrue from a properly structured set of LTDA programs. Load forecasting is an inherently complex and uncertain exercise that is not made materially more complex through the introduction of direct access. Indeed, including direct access participation in the load forecast is essential to ensuring that COS customers receive the full benefits of LTDA participation by reducing the utilities' projected incremental capacity and energy needs.

Finally, economies of scale in generation are largely a foregone artifact of the era of large central station coal generating stations. The least-cost marginal new generation resources today, wind and solar, are most cost effective at the appropriate scale and size suited to the resource site and availability. Similarly with storage. Distributed energy resources ("DER") can be cost effective for deployment to provide balancing area customer services to the extent that there are multiple uses for those resources and multiple revenue or payment streams to support them. This reduces the cost of those DERs for all users.

In sum, it would appear compelling that the potential benefits to all Oregon customers, both COS and LTDA participants, of LTDA programs far outweigh the costs those programs may impose.

Q1a. **What are the potential cost shifts?**

A1a. No material cost shifts should result from any long-term direct access program if that program is structured and conducted appropriately by the regulator. The Oregon Commission Staff made that specific finding for NLDA customers in their January 19, 2018 Staff Report. There the Staff stated, "…Staff finds that it is possible to create a NLDA program without undue cost shifts and that the Commission should adopt rules implementing such a program."[10]

[10] PUBLIC UTILITY COMMISSION OF OREGON, STAFF REPORT, Docket No. AR 614 & UM 1837, Order No. 18-031, Appendix A p. 3 of 10, January 19, 2018.

Similarly, the transition adjustments that are authorized to be collected from LTDA existing load customers during a transition to direct access beyond five years, if structured and calculated properly, should minimize any potential cost shifts to existing COS customers. One-time exit fees are also a possible mechanism to minimize potential cost shifts and protect existing COS customers. Such a regulatory structure for a direct access program of a one-time exit fee (calculated by Staff and not the utility) and assessed to direct access customers has been used successfully in Nevada to avoid cost shifts to existing COS customers.[11]

It should be noted that in Nevada there is generally no exit fee assessed to new load customers who seek direct access service from a competitive provider and not from the COS monopoly utility. The Public Utilities Commission of Nevada ("PUCN") held in an advisory opinion issued to Google, Inc.:

"…the PUCN hereby confirms that Google may comply with [applicable Nevada statutes on retail access] and **avoid an impact fee [emphasis in original]** by applying to [the utility] on a day of its own choosing to take bundled electric service on the following day and then discontinuing that service the day after…".[12]

The PUCN cited to the *Google* decision in finding in a recent order that no exit fee should be assessed against the new Raiders football stadium in Las Vegas, which sought direct retail access under Nevada law. The PUCN made this decision despite an estimated 22 MW in projected new load from the stadium and a request by the COS monopoly utility to assess an exit

[11] 3 *Casino Companies Face $126.5M in Exit Fees If They Leave NV Energy Grid*, 3 News Las Vegas, November 26, 2015.
[12] Public Utilities Commission of Nevada, Google Inc., Docket No. 17-04019 Advisory Opinion, p. 7, September 8, 2017

fee against the stadium developers in excess of $7M. There the PUCN found "…that [the utility] will not be burdened by increased costs as a result of the Stadium's proposed transaction, nor will [the utility's] remaining customers…" "…the Commission declines to assess an impact fee on the Stadium."[13]

Thus, consistent with the Oregon Staff finding in its Staff Report, the Nevada Commission has determined that new load direct access customers do not impose cost shifts onto existing COS monopoly utility customers and no exit fee is warranted. Similar in concept to the NLDA program, while the transition of existing customers may potentially result in cost shifts, transition charges that are structured to identify and offset the specific cost shifts that occur will hold remaining customers harmless.

Q2. [This response is left out intentionally]

Q3. Resource adequacy

Q3a. What is it?

A3a. Resource adequacy can be generally defined as:

> "…the ability of an electric power system to serve load across a broad range of weather and system operating conditions, subject to a long-run standard on the maximum frequency of reliability events where generation is insufficient to serve all load. The resource adequacy of a system thus depends on the characteristics of its load—seasonal patterns, weather sensitivity, hourly patterns—as well as its resources—size, dispatchability, outage rates, and other limitations on availability."[14]

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[13] Public Utilities Commission of Nevada, LV Stadium Events Company, LLC, Docket No. 18-09003, Order at paragraph 80, p. 31 (Jan. 30, 2019).
[14] Resource Adequacy in the Pacific Northwest, Energy and Environmental Economics, Inc., March 2019, p. 4.

For the purposes of this discussion, an "electric power system" is considered to be the collection of real or virtual resources available to a load serving entity ("LSE") where that LSE is a traditional monopoly utility serving retail customers or a competitive retail provider such as an ESS who would serve LTDA customers.

While there is no accepted national or regional standard for resource adequacy, the concept of resource adequacy finds it roots in the development of standards for electric system reliability. Electric reliability operating standards for minute-by-minute system reliability are the basis on which the electric industry plans for the long-term resource adequacy of its electric system.[15]

The Federal Energy Regulatory Commission ("FERC") is responsible for ensuring the reliability of the Bulk Power System ("BPS") in the U.S. under the provisions of the Energy Policy Act of 2005 (EPAct 2005). EPAct 2005 added a new section 215 to the Federal Power Act ("FPA"), which required a FERC-certified Electric Reliability Organization ("ERO") to develop mandatory and enforceable Reliability Standards, which are subject to FERC review and approval.[16] Once approved, the Reliability Standards may be enforced by the ERO, subject to FERC oversight. The FERC designated the North American Electric Reliability Corporation ("NERC") as the ERO in 2006.[17]

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[15] For a comprehensive overview of the relationship between FERC reliability standards and resource adequacy see: Resource Adequacy Requirements: Reliability and Economic Implications, Prepared for FERC, Johannes P. Pfeifenberger and Kathleen Spees, The Brattle Group, September 2013.
[16] 16 U.S.C. 8240.
[17] *Rules Concerning Certification of the Electric Reliability Organization; Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards, Order No. 672,* 71

Neither FERC nor NERC have an "official" definition of resource adequacy. But NERC does define "Adequacy." In the NERC Glossary of Terms, "Adequacy" is defined as:

> "The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."[18]

Again, an "electric system" can be any aggregation of real and virtual resources accumulated by an LSE to provide service to its retail customers.

NERC delegates its authority to oversee reliability and resource adequacy to regional reliability entities. WECC is responsible for coordinating and promoting BPS reliability in the Western Interconnection for NERC and ultimately FERC. The WECC assessment area is divided into six sub-regions: Rocky Mountain Reserve Group ("RMRG"), Southwest Reserve Sharing Group ("SRSG"), California/Mexico ("CA/MX"), the Northwest Power Pool ("NWPP), and the Canadian areas of Alberta ("WECC AB") and British Columbia ("WECC BC").

In 2012 NERC initiated an adequacy assessment pilot program. That program required each of its sub-regions in the U.S., including WECC, to report three adequacy metrics; 1) expected loss-of-load hours or loss-of-load probability ("LOLP"), 2) expected unserved energy ("EUE") and 3) normalized expected unserved energy (EUE divided by load).[19] These measures

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FR 8662 (Feb. 17, 2006), FERC Stats. & Regs. ¶ 31,204 (2006), order on reh'g, Order No. 672-A, 71 FR 19814 (Apr. 18, 2006), FERC Stats. & Regs. ¶ 31,212 (2006).

[18] NERC Reliability Standards Glossary of Terms, Version 0 Reliability Standards, 3/16/2007
[19] Pacific Northwest Power Supply Adequacy Assessment for 2024, Northwest Power and Conservation Council, Document 2019-11, October 31, 2019, p. 21-22.

of resource adequacy are reported to NERC by WECC by sub-region. Neither WECC nor NERC have specific required standards or even target levels for the three adequacy metrics reported.

The Northwest Power Planning and Conservation Council ("NWPCC")[20] in 2011 adopted an adequacy metric for the WECC NWPP sub-region which it publishes as LOLP, but is non-standard across other NERC regions.[21] NWPCC sets its threshold exceedance level for LOLP to be anything over a 5% likelihood of a shortfall (not necessarily an outage) occurring anytime in the year under study. This metric does not provide any information on the number of events, duration of events, or magnitude of events that occur during years that experience loss of load. Most NERC regions set their resource adequacy threshold for reliability at a loss-of-load event ("LOLE") of "1 in 10" standard, which is an outage one day in 10 years or 2.4 hours per year.[22]

The Northwest Power Pool organization[23] convened working groups during the summer of 2019 to examine the potential for a capacity sharing mechanism that could contribute to resource adequacy in the region. This was done under the rubric of a resource adequacy program.

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[20] The NWPPC is not a FERC/NERC reporting entity and has no responsibility to FERC, NERC or WECC. It is an independent entity formed as an interstate compact among Northwestern states pursuant to the authority of the Northwest Power Act.
[21] Resource Adequacy Requirements: Reliability and Economic Implications, Prepared for FERC, Johannes P. Pfeifenberger and Kathleen Spees, The Brattle Group, September 2013, Appendix A.
[22] Ibid.
[23] The NWPP is a voluntary organization started in 1941 of Northwest utilities established to coordinate resources to maximize efficient electricity production. The NWPP currently coordinates a number of programs under WECC standards. This organization should be distinguished from the region name of WECC sub-region which is also designated as the Northwest Power Pool or NWPP.

To date, the Northwest Power Pool has held a resource adequacy symposium, commissioned and published a resource adequacy study, established a resource adequacy committee and is in the process of creating a stakeholder advisory committee. The announced purpose of this effort is to establish a resource adequacy program that would allow utilities in the NWPP to forecast and manage resource adequacy in a coordinated manner. AWEC has a representative on this advisory committee.

The Northwest Power Pool, whose members include Oregon's jurisdictional electric utilities, had the following to say about how resource adequacy is currently managed by utilities in the region:

> "The current patchwork approach to resource adequacy inhibits the ability of utilities, regulators, and stakeholders alike to fully understand the region's capacity position and how it relates to utility resource plans. In the absence of a centralized, transparent program to administer resource adequacy within the region, utilities either plan their systems to meet their own resource adequacy needs, irrespective of potential benefits from the greater regional grid; or they make assumptions on the availability of market capacity to contribute to their resource needs, which may not align with the amount of physical capacity actually available." [24]

Resource adequacy apparently has neither a granular calculable algorithm nationally or regionally under NERC or WECC nor an agreed upon set of procedures and metrics in the Northwest. There does appear to be progress in the development of a Northwest Power Pool resource adequacy program to better account for natural load and resource diversity that exists across the region. If the Northwest Power Pool effort is successful in filling in some of these blanks, resource adequacy in the region would be enhanced. In fact, formal regional planning

[24] Exploring a Resource Adequacy Program for the Pacific Northwest, Northwest Power Pool, October 2019.

reserve sharing to increase resource adequacy and the benefits that such a program would produce for the region was discussed and recommended in a study sponsored by several Northwest utilities a year ago.[25]

Q3b. How is it provided?

A3b. Resource adequacy has traditionally been provided through the acquisition by LSEs[26] of sufficient generating and purchase power resources on a year-ahead or even multi-year basis to meet their forecasted peak system loads of their customers. Those purchase power resources could be long- or short-term bilateral contracts or market purchases in organized wholesale markets. These include firm liquidated damages contracts or WSPP Schedule C type resources. FERC has previously found that these types of contracts cannot be interrupted for reasons other than reliability and, thus, qualify for designation as network resources.[27] These market resources, therefore, can and do contribute to resource adequacy.

The LSE may or may not be the balancing authority responsible for dispatching those resources on a minute-by-minute basis to meet system reliability criteria enforced by NERC. But the LSE has the responsibility to make available to the balancing authority sufficient resources to meet those short-term reliability requirements. But the LSE's resource adequacy responsibility is a long-term one that requires planning and entering into commitments over a period of years.

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[25] Resource Adequacy in the Pacific Northwest, Energy and Environmental Economics, Inc., March 2019

[26] Again, the purposes of discussion consider LSEs to be both utilities who serve monopoly retail loads and ESSs who may provide retail service to LTDA customers.

[27] Preventing Undue Discrimination in Transmission Service, Order No. 890-B, 123 FERC P. 61,299, ¶¶ 165-66 (June 23, 2008).

In addition to the traditional means of providing for resource adequacy with the planning and procurement of generating or purchase power resources, there are a number of other means by which an LSE can provide resource adequacy. These include behind-the-meter distributed energy resources ("DERs") such as onsite generation, flexible load or load control (also known as demand response) and energy efficiency. All of these can provide for "apparent" load reductions behind-the-meter and contribute to system resource adequacy.

Despite this fact, the LOLP calculations provided annually by the NWPCC for the NWPP region do not consider the potential acquisition of these types of resources.[28] Nor do those LOLP calculations consider curtailment contracts. These omissions exclude proven demand-side resource categories that can contribute to providing resource adequacy to the extent that they can be newly acquired by a LSE and are not already incorporated into an existing load forecast.

Q3c. What regulatory requirements or market structures are used in other states with direct access to ensure resource adequacy?

A3c. There are a number of Western states that provide for some form of retail access and have requirements for resource adequacy. The two most relevant to the issue of the resource adequacy discussion in Oregon are California and Nevada, both for their geographic proximity to the State and their length of experience with retail access in those jurisdictions.

[28] Pacific Northwest Power Supply Adequacy Assessment for 2024, Northwest Power and Conservation Council, Document 2019-11, October 31, 2019, p. 7.

California

California Public Utilities Code § 380 requires that the California Public Utilities Commission ("CPUC"), in consultation with the California Independent System Operator[29] ("CAISO"), establish resource adequacy requirements for all LSEs within the CPUC jurisdiction. The CPUC Energy Division administers the resource adequacy program, reviews all related compliance filings, and advises the presiding Administrative Law Judge in ongoing resource adequacy proceedings.

The CPUC adopted a resource adequacy framework and set forth two goals for its resource adequacy program. First, resource adequacy must ensure that LSEs provide sufficient resources to CAISO to ensure the safe and reliable operation of the grid in real time. Second, it must provide appropriate incentives for the siting and construction of new resources needed for reliability in the future.

In order to meet these goals, the CPUC established resource adequacy requirements for all LSEs within the CPUC's jurisdiction, including investor-owned utilities ("IOUs"), energy service providers ("ESPs"), and community choice aggregators ("CCAs"). The CPUC's policy guides resource procurement and promotes infrastructure investment. It requires that LSEs procure capacity so that capacity is available to the CAISO. There are three distinct resource adequacy requirements for LSEs: system (effective June 1, 2006), local (effective January 1, 2007) and flexible (effective January 1, 2015).

[29] CAISO is a FERC jurisdictional entity that is the balancing authority for most of California and portions of Nevada.

System requirements are determined based on each LSE's adjusted forecast plus a 15% planning reserve margin. Local requirements are determined based on an annual CAISO study using a 1-10 weather year and an N-1-1 contingency. Flexible Requirements are based on an annual CAISO study that currently looks at the largest three-hour ramp for each month needed to run the system reliably.

LSEs must make both annual and monthly resource adequacy compliance filings with the CPUC. Annual filings contain system, local, and flexible compliance requirements for the coming year. For the system showing, LSEs are required to demonstrate that they have procured 90% of their system obligation for the summer months the coming compliance year. Additionally, each LSE must demonstrate that they meet 90% of its flexible requirements and 100% of its local requirements for each month of the coming compliance year. In the monthly filings the LSEs must demonstrate they have procured 100% of their monthly system and flexible resource adequacy requirement.

In addition to the LSE-required filings, the CPUC serves an annual Resource Adequacy subpoena on the CAISO requesting data in 21 broad categories.[30] Those categories are:

(1) Resource adequacy import allocations,

(2) supply plans filed and monthly supply plan validations for LSE resources,

(3) list of units confirmed to provide resource adequacy to the CAISO,

[30] See: http://www.caiso.com/Documents/CPUCAnnualResourceAdequacySubpoenaIssued030620.html

(4) economic bids and self-schedules,

(5) CAISO settlement quality meter data,

(6) access to OMS data,

(7) quarterly CAISO Masterfile data,

(8) next year's flexible capacity needs assessment data and allocations,

(9) access to CIRA data base,

(10) energy management system (EMS) data,

(11a) capacity procurement mechanism (CPM) and capacity solicitation process (CSP) results,

(11b) CPM and reliability must run (RMR) settlement data,

(12) reliability event reports sent to WECC,

(13) demand response (PDR/RDRR) and non-generating resource (NGR) settlement data,

(14) CPUC jurisdictional LSE annual and monthly deficiency notifications,

(15) local capacity study data,

(16) local residual analysis,

(17) CPM and RMR designation capacity and costs allocations,

(18) notices of intent to retire/mothball/return to service,

(19) California Energy Commission subpoena data,

(20) resource adequacy availability incentive mechanism (RAAIM) data,

(21) demand response (DR) registration system information.

As can be seen from the detailed resource adequacy protocols and requirements imposed by the CPUC on all the state's LSEs, including ESPs (California's equivalent to Oregon's ESSs), California has a robust process in place to assure resource adequacy. It should be noted for the Commission that five of Oregon's certificated ESSs are LSEs in California and apparently fully comply with the resource adequacy requirements of the CPUC. As the Oregon Commission recently found, it is fully empowered to adopt rules defining what an ESS must do to demonstrate that it is able to comply with capacity requirements as a necessary part of a resource adequacy standard.[31]

Nevada

Under Nevada statute, loads of 1 megawatt or more are able to apply to the Nevada Public Utilities Commission ("PUCN") for retail access from a competitive retail provider.[32] The pertinent sections of the Nevada statute (enacted in 2000, but recently amended in 2019) that relate to the issue of resource adequacy are the following:

NRS 704B.310(6)(c)

"6. In determining whether the proposed transaction will be in

the public interest, the Commission shall consider, without limitation:…

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[31] Docket No. UE 358, Order No. 20-002 at 9 (Jan. 7, 2020).
[32] NRS 704B.

…(c) Whether the proposed transaction will impart system reliability or the ability of the electric utility to provide electric service to its remaining customers." [33]

And a new Section 9 added in 2019, in part 3:

"3. The Commission may adopt regulations requiring each provider of new electric resources to submit to the Commission such information as the Commission determines is necessary to ensure that:

(a) Each provider of new electric resources has sufficient energy, capacity and ancillary services, or the ability to obtain energy, capacity and ancillary services, to satisfy the demand of each eligible customer purchasing energy, capacity or ancillary services from the provider;

(b) Eligible customers served by a provider of new electric resources will receive safe and reliable service from the provider;" [34]

These sections could be construed to relate to resource adequacy via the provider's ability to obtain resources to reliably meet the demand of its customers. The statute and accompanying PUCN regulations have been in place since 2001 with the pertinent amendments in 2019 indicated above. There have been a number of large commercial and industrial customers who have applied for authority to leave the monopoly utility provider and obtain power from a competitive retail provider.[35] None of those entities have been charged a resource adequacy fee per se by the PUCN. As noted above, there have been exit fees charged in some instances,

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[33] SB 547, 80th Session (2019), p.20.
[34] SB 547, 80th Session (2019), p. 15.
[35] SB 547: A History of NRS 704B and Energy Deregulation in Nevada, Senator Chris Brooks, District No. 3.

primarily on existing load customers who applied to exit the system. But there have been no ongoing resource adequacy charges imposed to date.

Q3d. Why is it important or not important?

A3d. Resource adequacy is important. It is import for both federal and state regulators to ensure that customers have reliable and adequate service. Reliable in the short-term and adequate in the long-term. Customers expect it and they deserve it.

But the relative importance of resource adequacy and the methods to ensure it should be at the customer's choosing as long as the choices made by the customer do not negatively impact other customers on the BPS. Shell Energy North America, an Oregon ESS, stated it best in recent comments to the Commission:

> "The Commission should reject any so-called 'reliability charge' for long-term or new load direct access customers. A direct access customer and its ESS are responsible for the procurement and transmission resources necessary to ensure service reliability."[36]

This Commission has the authority to enact regulations to ensure that resource adequacy is achieved, just as the California PUC has done, and to impose those requirements on ESSs who provide services to LTDA customers. But by the imposition of those requirements the Commission should recognize that additional charges for resource adequacy are unwarranted and unnecessary. They are not imposed in California and they are not imposed in Nevada.

[36] PUBLIC UTILITY COMMISSION OF OREGON, DOCKET NO. AR 614, Comments of Shell Energy North America, July 6, 2018.

Dated this 16th day of March 2020.

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