BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 2024

In the Matter of ALLIANCE OF WESTERN ENERGY CONSUMERS, Petition for Investigation Into Long-Term Direct Access Programs.	Staff Opening Comments

Background

Oregon's long-term direct access (LTDA) programs began with Oregon's Electric Industry Restructuring Law, SB 1149. Oregon law requires that the Oregon Public Utility Commission shall develop "policies to eliminate barriers to development of a competitive retail market structure"[1] while also ensuring that "[t]he provision of direct access to some retail electricity consumers must not cause the unwarranted shifting of costs to other retail electricity consumers of the electric company."[2]

Oregon currently has two types of LTDA programs, each with separate enrollment level caps. Oregon's first LTDA program began in 2002, for industrial and commercial customers currently served by one of Oregon's investor owned utilities, using at least 30 kW per month and electing to leave the incumbent's regulated retail rate in favor of service from an Electric Service Supplier (ESS) or pay a market-based rate. In 2018, through the AR 614 process and the rules adopted in Order No. 18-341, the Commission expanded Direct Access, requiring utilities to create a New Large Load Direct Access program for new, previously unplanned for load larger than 10 MWa. This program includes a soft cap of six percent of a utility's 2017 weather normalized load.

After a petition to open a general investigation into LTDA programs by the Alliance of Western Energy Consumers (AWEC), this docket, UM 2024, was opened in Commission

[1] ORS 757.646(1).
[2] ORS 757.607(1).

Order No. 19-721. The purpose of Staff's opening comments in this non-contested phase is to provide background on the following:

1. Potential benefits and potential costs to customers from long-term direct access participation;
2. How other states are handling access to customer choice and access to wholesale markets for different customer classes in the Western Interconnection, including the cost of legislative requirements; and
3. Resource Adequacy in the context of long-term direct access programs.

Potential Benefits and Costs from Long-Term Direct Access Participation

Under traditional cost of service rate regulation, investor owned utilities (IOUs) are considered natural monopolies, and granted monopoly status over their service territory in exchange for guaranteeing to provide safe and reliable service to all. This is known as the regulatory compact, pursuant to which utilities are able to recover all operating costs plus a reasonable return on capital investment. This ensures customers have their power needs met, without the inefficient duplication of facilities. The objectives of traditional rate regulation of fully integrated energy public utilities do not include achieving (or approximating) the results of the perfect competition model of economics.[3]

Beginning in the 1990's, many states began thinking about whether it was appropriate to deregulate the electricity sector, largely with the hopes that injecting competition into the sector and allowing retail choice (giving customers the option to choose their energy provider) would benefit customers through lower electricity prices and increased product offerings. The standard means is to separate the integrated utilities' distribution from its transmission and generation. Allowing competition in the generation sector while avoiding uneconomic duplication of distribution systems.

In this section, Staff presents a number of commonly cited potential costs and benefits related to increasing access to retail choice. Staff does not intend for this list of potential cost and benefits to be exhaustive, but merely illustrative. In these comments, Staff is not making any assertion as to whether or not these potential benefits and risks are present in Oregon's current Long-Term Direct Access programs as currently designed, and will save any such arguments for the contested case phase of this docket.

<u>Potential Benefits</u>

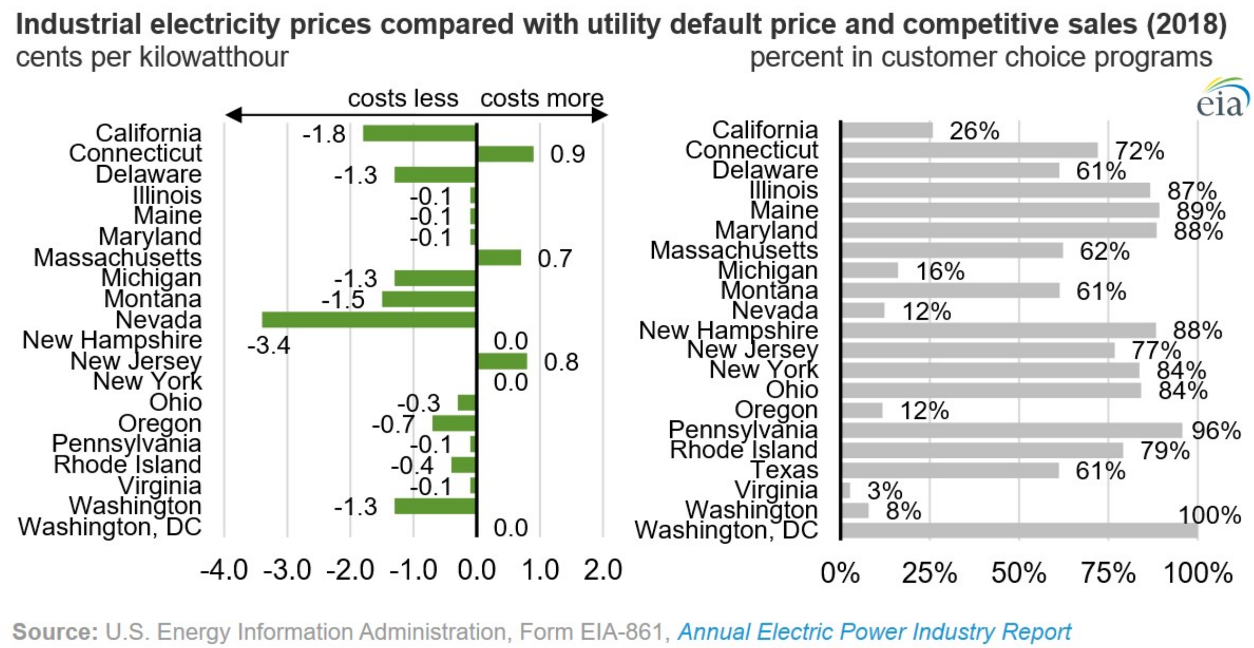
<u>Cost Savings for Participating Customers</u>

As noted above, IOUs have traditionally been granted natural monopoly status and regulated as such, without the intent of achieving the results of perfect competition. While not attempting to achieve the results of perfect competition, an increase in the amount of generation and energy service competitors through retail choice programs may prompt operational, technological, and management efficiencies which ultimately reduce generation costs and improve generators'

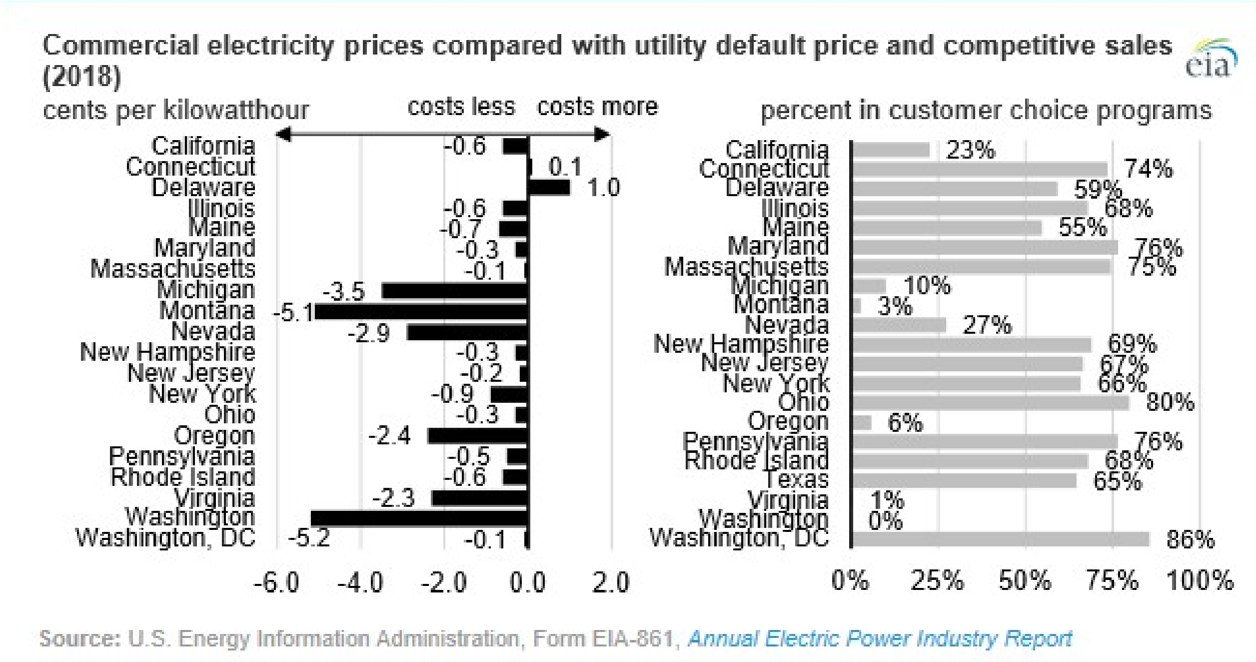
[3] See, generally, pages 93-104 of "Principles of Public Utility Rates," James C. Bonbright, 1961.

performance. In order to attract customers away from incumbent utilities these costs savings may then be realized by customers participating in retail choice.

There is some evidence that Industrial and Commercial customers who purchase power through a retail choice program pay less per kWh than with utility default prices, as shown below in the figures produced by the Energy Information Association (EIA).[4]



[4] EIA. Accessed March 4, 2020. https://www.eia.gov/todayinenergy/detail.php?id=41853.



<u>Greater Consumer Choice/Control</u>

In theory, increased competition will also lead to an increase in the amount of products a customer is able to choose from to best meet their individual energy needs. Competitive suppliers may try to differentiate their service options along several lines including dynamic pricing structures, demand response programs, price guarantees, firmness of service, energy source, billing and payment arrangements, and additional incentives to attract customers. This in turn should lead to increases in customer satisfaction as a larger suite of options can better cater to a particular customer's needs.

<u>Expansion of Renewable Energy</u>

In order to attract large customers who may have corporate renewable energy or carbon neutral goals, competition may induce competitive suppliers to offer an increasing number of renewable offerings. In Oregon, ESSs that meet or exceed RPS requirements applicable to incumbent utilities allow for an increase in the amount of renewable energy provided to Oregon retail customers, particularly when the competitive customer may have otherwise located in a different state.

<u>Benefits to COS Customers</u>

Theoretically, there may be benefits to remaining COS customers from some level of LTDA participation. For example, because many utility costs are shared among customers, a utility may be able to avoid an incremental investment and potentially avoid added costs to COS customers if cause causation principles are not perfectly adhered to.

Further, in the case of Oregon's NLDA program, if a large customer, who, but for the NLDA program would have located elsewhere elects service through the NLDA program, this customer may spur growth in the surrounding area which increases COS load. If this load is truly unplanned for, and the IOU has not incurred any costs in planning for said customer, the IOU's revenue requirement would then be spread over a greater number of kWh, thereby reducing the COS rates customers.[5]

Staff realizes that when parties discuss the benefits to COS customers that may result from increased participation in LTDA programs, these often appear to be potential, theoretical benefits rather than direct, certain benefits. While this may be the case, and it is certainly important to discuss potential benefits to COS customers, Staff notes that a well-designed LTDA program prevents unwarranted COS shifting, essentially holding remaining COS customers harmless as customers elect service through a competitive supplier. When COS customers are held harmless, they should be indifferent between other customers choice of energy supplier.

<u>Potential Costs and Risks</u>

<u>Cost Shifting</u>
The most noted risk to COS customers from increased participation in electric retail choice is that of cost shifting. Cost shifting generally refers to costs that would otherwise be borne in part by the customer who has left the system in favor of an alternate electricity supplier but who now gets to bypass the cost, leaving the departing customer's share of the cost to be collected from the remaining COS customers. As these costs are now be spread over a smaller number of kWh, prices to remaining COS customers rise and have therefore "shifted" away from the direct access customer and towards the COS customer. Cost shifting can take many forms including:

1. *Stranded Costs* – Stranded costs can be defined as the decline in the value of electricity-generating assets due to restructuring of the electric industry, i.e. the amounts by which the book values of utility generation assets exceed their market value. Examples of stranded cost categories include unrecoverable costs of generation-related assets, long-term contracts for power that would be uneconomic with lower market prices for power, and regulatory assets that regulators would have allowed utilities to collect that would be uneconomic in a competitive market.[6]
2. *POLR Costs* – Another possible risk for COS customers is the cost that the incumbent utility must incur to serve as the Provider of Last Resort (POLR). If the incumbent IOU is required to serve as the POLR for LTDA customers, absent an appropriate mechanism to either design rates such that costs for providing this service are recovered from the customers requiring emergency service, or removing the POLR obligation from the utility, the recovery of any costs the incumbent must incur to serve as the POLR for LTDA will come from COS customers or utility, resulting in a subsidy to the departing customer.
3. *Balancing Costs* – If the incumbent utility is also a balancing authority, in order to ensure COS customers do not pay for balancing services such as flexible capacity to balance load when LTDA customers demand is greater than the energy supplied by the ESS, there must be a mechanism to recover any such costs. One example of a mechanism designed to recover this type of cost are energy

[5] Staff notes that the Commission has not traditionally considered economic development as a factor for consideration in ratemaking, and is not advocating it should do so here, but is merely noting a theoretical benefit.
[6] Congressional Budget Office, Electric Utilities: Deregulation and Stranded Costs, Oct. 1998. https://www.cbo.gov/sites/default/files/105th-congress-1997-1998/reports/stranded.pdf

imbalance charges between an IOU and ESS through the IOU's Open Access Transmission Tariff (OATT).

Reliability & Resource Adequacy Risks

There are concerns that as retail choice participation increases, resource adequacy may be negatively affected. Large customers who leave the system may do so because they have different levels of reliability needs than provided under their incumbent utility. If these customers are then willing to elect service from ESSs who may offer less reliable services system reliability and resource adequacy may be adversely affected.

Another potential risk to reliability could be realized if retail choice customers largely elect to procure energy from intermittent generation resources such as solar and wind, if the capacity of those resources is not enough to meet peak requirements. If such choices lead to a significant enough change in the generation mix, this could raise reliability as a larger share of the total generation mix becomes non-dispatchable absent appropriate resource adequacy mechanisms.

Other Potential Costs

Additionally, as Staff and electric companies mentioned in Docket No. AR 614, there is even the potential for cost shifting to occur in the case of new load choosing service from an ESS rather than the incumbent. Though more difficult to quantify, these potential cost shifts include:

> *"1. The opportunity costs associated with the program: new load presents important value to the system for optimization of generation development, purchases, and operation that is foregone when a large customer does not take generation service from the electric company.*
> *2. The foregone electric company demand response program opportunities.*
> *3. The actions taken by cost-of-service customers that create the possibility of the New Large Load Direct Access Program (NLDA) option, including procurement of reserves that, in part, serve the purpose of facilitating default service, if necessary.*
> *4. The inherent risk to the system associated with the NLDA program."*[7]

Survey of Western States

Since the late 1990's, a number of states across the country have allowed customers some form of access to competition in electric markets. In this section, Staff briefly discusses the States within the Western Interconnection that currently offer, or are considering, some level of retail choice. Staff does not present this as an exhaustive list of customer choice offerings, but is merely presenting an illustrative look at how states in the Western Interconnection are (or are planning to) approaching the issue of allowing customers access to wholesale markets or are otherwise implementing customer choice programs.[8]

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[7] Docket No. AR 614, Order No. 18-341.

[8] Though Montana implemented partial retail competition in 1997 with the passage of SB 390, Staff has excluded Montana from this discussion due to the passage of the Electric Utility Industry Generation Reintegration Act in 2007 which, with limited exceptions, reversed restructuring efforts in the state, and suspended retail competition.

Staff notes that while helpful to consider how different states are implementing similar programs, and grappling with the idea of electric restructuring, each state ultimately presents its own unique set of circumstances. It is worth noting that generally, outside of the WECC, states with retail rates that are fully or partially deregulated are regulated by Regional Transmission Organizations (RTOs). The only WECC state that currently operates a direct access program similar to Oregon's LTDA programs is California, which also has an RTO/ISO structure in the form of the California Independent System Operator (CAISO).

California

California is a state with partial retail competition. California's Direct Access (DA) program was implemented in 1999. In the midst of California's energy crisis, demand for electricity exceeded the generating capacity available to the wholesale market and electricity prices increased to between $250 and $450 MWh, eventually leading to the suspension of the DA program in 2001 with Decision 01-09-069.[9]

The DA program was re-opened on a limited basis in 2009 with the passage of SB 695 and is available to eligible non-residential customers only.[10] Currently, the program is at full capacity, and the new customers wishing to participate in DA must try to join through an annual lottery process with one of the state's three IOUs.[11] In 2019, the passage of SB 237 ordered the California Public Utility Commission (CPUC) to increase the annual DA limit by 4,000 GWh, and also requires the CPUC to provide recommendations to the legislature by June 2020 regarding a schedule for reopening DA for all remaining non-residential customers.

Program Design:

- In 2019, California passed SB 520, officially designating the incumbent IOU as the designated POLR within its service territory. The bill also provides for new entities to be designated to provide POLR services if the IOU no longer wishes to provide POLR services.[12]
- To recover stranded costs from DA customers, and ensure that remaining COS customers are indifferent to customer departures a non-bypassable Power Charge Indifference Adjustment (PCIA) is charged to DA customers. The PCIA is updated annually, and a departing customer's PCIA is based on the year in which they left the system.[13] For example, if a customer switched to DA in 2012 they would pay the "2013 vintage PCIA" which only includes above market costs of pre-2013 vintaged power procured by the IOU.[14] In August 2018, the CPUC removed a 10-year limit on recovering costs for post-2002 utility owned generation as well as eligibly energy storage resources.[15]

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[9] Lisa M. Quilici et al. *Retail Competition in Electricity What Have We Learned in 20 Years*, 2019.
[10] In California, residential customers are afforded some level of customer choice through Community Choice Aggregators.
[11] https://www.cpuc.ca.gov/General.aspx?id=7881.
[12] https://leginfo.legislature.ca.gov/faces/billStatusClient.xhtml?bill_id=201920200SB520
[13] CPUC Decision 19-080-022 at 6.
[14]https://www.cpuc.ca.gov/uploadedfiles/cpuc_public_website/content/news_room/fact_sheets/english/pciafactsheet010917.pdf
[15] CPUC Rulemaking 17-06-026, Alternate Proposed Decision Modifying the Power Charge Indifference Adjustment Methodology, Page 157.
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M232/K140/232140817.PDF

- To comply with other legislative and statutory mandates, DA customers are also subject to a number of additional non-bypassable departing load charges including a Public Purpose Charge, Competition Transition Charge, Nuclear Decommissioning charge, Department of Water Resources bond charge.
- ESPs providing energy under DA must procure resource adequacy to meet peaking capacity and must comply with the state's RPS requirements.
- Retail suppliers (including ESPs) who make an offering to sell energy that is consumed in California must disclose their electricity sources and the associated greenhouse gas emissions intensity for the previous calendar year to the California Energy Commission.[16]

Arizona

Arizona is not currently a deregulated state; however, the Arizona Corporation Commission (ACC) is currently considering the creation of a regulated competitive market in Docket No. RE-00000A-18-0405.

In Docket No. RE-0000A-18-0405, the ACC has recently released two sets of draft rules for electric restructuring in the state.[17] Both sets of draft rules would allow all customers, including residential customers, to participate in customer choice.

However, the draft rules differ in that Draft A allows all customers, regardless of size to directly choose their energy provider while Draft B requires that customers who do not meet the 100 kW monthly demand threshold aggregate their load to a combined monthly demand of at least 400 kW participate in customer choice. The drafts also differ in their treatment of who may provide competitive services. Draft A does not allow the incumbent utilities to participate in retail competition, while Draft B allows incumbent utilities and ESPs to participate.

Possible Program Design:

- There are two POLR options presented in the draft rules: Draft A would have designated ESPs serve as the POLR, as determined by the Commission, while Draft B would allow either the ESPs or the Utilities to serve as the POLR.
- Both drafts include a Competition Transition Charge to recover stranded costs. However, the rules note that the "Affected Utilities shall take every reasonable, cost-effective measure to mitigate or offset Stranded Cost by reducing costs, expanding wholesale or retail markets, or offering a wider scope of permitted regulated utility service for profit, among others."[18] Further the draft rules note that the "Affected Utilities are not owed stranded costs due to a transition to competition"[19] and that if the "Affected Utility elects to retain assets, the Commission will assume the Affected Utility is not owed any stranded costs."[20]

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[16] California Public Utilities Code – Article 14 398.4
[17] Docket No. RE-0000A-18-0405, Correspondence from Commissioners, filed 2/10/2020. https://docket.images.azcc.gov/E000004845.pdf
[18] Draft Rule, R14-2-1607. Docket No. RE-0000A-18-0405, Correspondence from Commissioners, filed 2/10/2020.
[19] *Ibid.*
[20] *Ibid.*

- Each Load serving entity (LSE) must prepare a statement that includes information regarding actual pricing structure or rate design, including an explanation of price variability and price level adjustments that may cause the price to vary.
- ESPs must also report to the types of services offered, among others, their kW and kWh sales to consumers by customer class, revenues from sales by customer class, the value of all assets used to serve Arizona customers and the accumulated depreciation, retail kWh sales and revenues disaggregated by term of the contract and type of service, and a tabulation of Arizona electric generation plants owned by the ESP broken down by generation technology, fuel type, and generation capacity.
- The rules propose a System Benefits Charge to recover non-bypassable rates or related mechanisms to recover the applicable pro-rata costs of System Benefits.

Nevada

Pursuant to Chapter 704B of the Nevada Revised Statutes and Chapter 704B of the Nevada Administrative Code, eligible customers with load greater than 1 MWa may submit an application with the Nevada Public Utility Commission (PUCN) to purchase energy, capacity, and/or ancillary services from a provider of new electric resources, and can effectively become distribution only customers.

To qualify as a new electric resource, the energy, capacity, or ancillary services being purchased must be "[f]rom an identifiable generation asset that is not owned by an electric utility or is not subject to contractual commitments to an electric customer; or [b]y way of market purchases through a provider of new electric resources."[21]

Program Design

- Under NRS 704B, any submitted application must include, information regarding points of delivery, ancillary services, transmission services, and the new electric resources to be supplied by the provider.
- The customer wishing to exit the system must obtain the required contractual rights for an additional amount of energy equal to 10 percent of the total amount of energy the customer is purchasing for its own use, and the capacity and ancillary services associated with the additional amount of energy. The eligible customer must agree to contract the additional 10 percent to their incumbent IOU.
- If the PUCN approves the application, the PUCN must order any terms and payments necessary to ensure that the proposed transaction will not harm the public interest. The customer is also charged its load-share portion of any unrecovered deferred accounts balance and the annual assessment of any other tax, or fee as required by NRS 704B.360.
- Providers of new electric generation are required to comply with Nevada's RPS standard.
- New customers who would have a peak load of 10 megawatts or more in the service territory of an electric utility within 2 years of initially taking electric service, are only required to pay costs, fees, charges or rates which apply to current and ongoing legislatively mandated public policy programs, as determined by the PUCN.[22]

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[21] NRS 704B.110.
[22] NRS 704b.310(8).

Washington
While Washington is neither a fully or partially deregulated state, there does appear to be limited retail choice in Washington due to the fact that state law does not grant exclusive service territory to a utility, and utilities (investor owned, PUDs, municipals, etc.) enter into voluntary service area agreements (i.e. special contracts). Essentially, this provides some level of retail choice in Washington.

For example, Puget Sound Energy's (PSE) Schedule 449, Retail Wheeling Service, allows eligible large customers to supply power from a power provider other than PSE. This is a closed class of customers. Microsoft also takes service pursuant to a special contract with PSE.

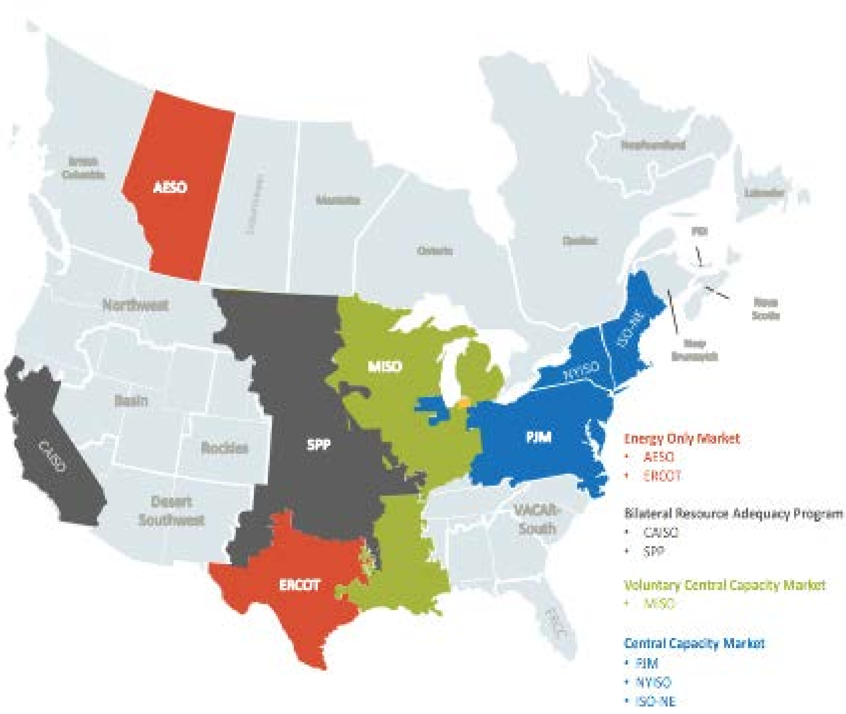
Resource Adequacy

Resource adequacy (RA) is the ability of a given area or entity to meet the electrical demand of its consumers during extreme conditions. It requires having sufficient generation or demand-side response available to provide power in any number of different circumstances. It can be measured in any time horizon or for any entity, which may result in different questions and answers. In the long term, when viewed on a regional basis, measurement of resource adequacy can be difficult to forecast. In depth studies require inputs and assumptions regarding the decisions of many different actors. The end result is that the results may lack precision and power. However, a long-term study that only focuses on a single entity can lack the ability to accurately measure market and third-party options in the analysis and can lead to inefficient or not fully informed conclusions. When viewing resource adequacy in the short-term, the measurement can be much more precise, but the ability to use the information to take corrective action may be limited. Thus, the optimal means to measure and ensure resource adequacy requires the use of multiple studies and reviews of different scopes and time horizons. The state of Oregon is at a further disadvantage given that unlike much of the rest of the US, there is not a single governing market operator. A single market operator has planning and implementation advantages, which can ease the difficulties of ensuring resource adequacy. The Oregon PUC has regulatory authority over three significant entities in the northwest, but lacks clear insight into the operation of many of the smaller producers within the state and any producer out of the state, in a connected but disjointed market.

How Resource Adequacy is Provided
Long-term resource adequacy in Oregon is addressed through the PUC's Integrated Resource Planning (IRP). The Oregon regulated utility develops an IRP through a robust public process and files a final IRP with the OPUC two years following the approval of the preceding plan. A forecast of future loads, an assessment of existing resources, and the identification of additional generating capacity needed to support customer demands are essential to the IRP process. Oregon currently has no uniform short-term mechanism to ensure resource adequacy like CAISO's program discussed below. Instead, the utilities in Oregon are mandated to provide safe and reliable power and rely on the iterative long-term planning process to ensure that the loss of load expectation never falls below a set level. If capacity becomes constrained in the region, utilities may find it difficult to handle unforeseen events.

Resource Adequacy in this Docket
Under current Commission policy, the POLR is ultimately responsible to provide resource adequacy for any customer for which it has this obligation in Oregon. The Commission could choose to separate existing POLR requirements from RA if it so chooses but it may be difficult to achieve without a central market operator to ensure market operation. Another option would be to alter the POLR requirements, by identifying the optimal choice to provide resource adequacy for customers who have opted to procure their power from third-party providers and not the incumbent utility. In coming to this determination, the Commission must consider the direct access mandate and laws set forth by the state legislature, the risk to the system, and the efficiency of any particular solution given the current and potential future circumstances we face in Oregon. The Northwest Power Pool (NWPP) is attempting to create a resource adequacy program in the region. This would be a voluntary program that would set standards for resource adequacy for all participating members. Further, the program would aim to ensure RA in the 1-4 year timeframe. The Commission is also investigating the value of various capacity resources in OPUC Docket UM 2011. As mentioned previously, this short-term horizon is not currently covered by any uniform program in Oregon. If a region wide RA program were to exist, it may alter the scope of risk presented by direct access customers and also the possible solutions that exist.

Resource Adequacy in Other Areas



[23]

Bilateral Markets
California implemented a resource adequacy program when the State Legislature enacted Section 380 of the Public Utilities Code. This required the state PUC and CAISO to work together to

[23] Northwest Power Pool February 7, 2020, Resource Adequacy Program Public Webinar

develop a program which required all load serving entities (LSE) to maintain physical generating capacity and electrical demand response adequate to meet its load requirements, including, but not limited to, peak demand and planning and operating reserves. Generally, LSE's are to show on a monthly basis that they own or have contracted with sufficient resources to meet their share of the CAISO system's peak demand, plus a Planning Reserve Margin ("PRM") of 15%. Additionally, LSE's located in transmission restricted load pockets must also procure a percentage of its RA from local resources. Finally, another percentage of the RA resources must be flexible enough to ramp up or down on short notice to meet variations in load and intermittent energy production.

The Southwest Power Pool has a program similar to CAISO, whereby "Load Responsible Entities" (LRE) are tasked with ensuring resource adequacy. A planning reserve margin is set based on a loss of load study which ensures that the LOLE is below 1 day in 10 years. Each resource has an effective load carrying capability, and the LRE is required to submit an annual workbook that shows that it possesses sufficient resources to meet the planning reserve margin.

Central Energy and Capacity Markets
Other states with Independent System Operators and more developed electrical markets have created capacity markets. In areas like the Pennsylvania, New Jersey, Maryland Power Pool (PJM) and ISO New England, capacity markets are established that have suppliers that bid into the market and load serving entities which can purchase capacity to ensure resource adequacy. The market operator is in charge of ensuring there is sufficient capacity and transmission to ensure safe and reliable power.

In energy only markets like the Electric Reliability Council of Texas (ERCOT), the price of electricity is more relied on as a mechanism to produce sufficient RA. During a peak event in July 2018, day-ahead energy prices approached $2000/MWh. In addition to a high market price cap, ERCOT also performs a bi-annual Capacity, Demand, and Reserves (CDR) report, a quarterly Seasonal Assessment of Resource Adequacy (SARA) and maintains a planning reserve margin of 13.75 percent. Both the CDR and SARA use load forecasts and expected generation resources to review the ability of the region to meet demand. The CDR reviewing the summer and winter peaks in a several year timeframe, and the SARA reviewing the upcoming season and incorporating an expectation of plant outages.

In both capacity and energy only markets, the market operator is tasked with ensuring that the market can function at all times and in the most extreme events. The use of market incentives and planning, as well as extra demand side resources during an emergency event are the main tools used to keep the market running.

This concludes Staff's opening comments.

Dated at Salem, Oregon, this 16th day of March, 2020.

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