Davison Van Cleve PC
Attorneys at Law
TEL (503) 241-7242 ● FAX (503) 241-8160 ● jog@dvclaw.com
Suite 450
1750 S Harbor Way
Portland, OR 97201

September 15, 2022

Via Electronic Filing

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

Re: Docket No. AR 651

Dear Filing Center:

Please find enclosed the Comments of the Alliance of Western Energy Consumers in the above-referenced docket.

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

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

AR 651

In the Matter of Rulemaking Regarding Direct Access Including 2021 HB 2021 Requirements.	)	COMMENTS OF THE ALLIANCE OF WESTERN ENERGY CONSUMERS

I. INTRODUCTION

The Alliance of Western Energy Consumers ("AWEC") submits the following comments and redlines in the above-referenced docket regarding Staff's Division 38 Direct Access ("DA") Regulation Straw Proposal, filed September 1, 2022. The comments below specifically address caps and behind-the-meter ("BTM") load growth, non-bypassable charges, and preferential curtailment. Attached hereto as Attachment A are redlines to Staff's Straw Proposal.

II. COMMENTS

A. Provider of Last Resort and Preferential Curtailment

Staff's newly proposed OAR 860-038-0290 – the preferential curtailment rule – would impose a preferential curtailment requirement on DA customers, or impose a capacity charge on Electric Service Suppliers ("ESSs") or DA customers if preferential curtailment is infeasible, in addition to Resource Adequacy ("RA") requirements. AWEC believes that RA requirements for ESSs will mitigate any provider of last resort ("POLR") risk utilities have and therefore supports Staff's proposal to "recommend requirements for an ESS to demonstrate [RA]

DAVISON VAN CLEVE, P.C.
1750 SW Harbor Way, Suite 450
Portland, OR 97201
Telephone: (503) 241-7242

either through participation in a regional RA program or a statewide program in Docket No. UM 2143."[1] However, AWEC does not support Staff's proposed preferential curtailment or capacity charge requirements. This construct results in uneconomic investment in curtailment infrastructure that is unlikely to ever be used and provides uncertain benefit even in the event of use, or would result in double charging for capacity. These realities create unwarranted and unnecessary barriers to DA participation.[2] A scenario where there is no market energy available is highly unlikely to occur, and it is infinitely more unlikely that preferentially curtailing DA customers alone will allow for uninterrupted service to cost of service ("COS") customers. The markets at issue are regional markets with thousands of MWs transacted every day by dozens of utilities and other market participants. If these markets fundamentally break down, there will be larger problems than the supply to a few DA customers.[3]

Moreover, these requirements are all the more unwarranted given the requirement that DA customers acquire RA through a regional or state-mandated program (which AWEC supports). By securing RA, these customers will have conclusively secured the capacity necessary to meet their loads. Thus, even if an ESS stops serving its customers, or even if the market fundamentally fails, the capacity necessary to serve DA customers will have been acquired and will exist in the market.

---

1 Docket No. AR 651, Staff's Straw Proposal, at 1 (Sep. 2, 2022).

2 There is no evidence in the record or available to AWEC regarding the costs of achieving preferential curtailment or the factors that would make preferential curtailment infeasible.

3 Preventing the DA program from growing so large that this statement no longer holds true could be a basis for the Commission to impose a cap on the program, which directly relates to Staff's first proposed criteria for DA program caps if, among other things, the size of the program could compromise system reliability.

DAVISON VAN CLEVE, P.C.
1750 SW Harbor Way, Suite 450
Portland, OR 97201
Telephone: (503) 241-7242

Because the costs likely substantially outweigh the benefits, Staff's proposed preferential curtailment rule should be removed at this time. At a minimum, the Commission should defer any decision on the proposed preferential curtailment rule until after the contested case phase when a factual record supporting a decision exists.

Although AWEC does not support adoption of a preferential curtailment rule at this time, AWEC has substantive considerations in the interest of continuing the discussion and providing feedback to Staff. First, preferential curtailment could be effectuated through contractual means rather than physical. Contractual curtailment would require DA customers to self-curtail their load or face substantial financial penalties. This would achieve the same result as Staff's rules while avoiding unnecessary capital investment.[4] While this still raises a concern regarding duplicative charges if these same customers are contracting for RA, contractual curtailment would eliminate AWEC's concerns regarding market barriers and uneconomic investments. There may also be other alternatives. For example, an ESS could be required to assign RA resources it acquires for its DA customers to the incumbent utility in the event of a loss of service for whatever reason. Regardless, there is currently insufficient evidence to demonstrate the need for preferential curtailment of DA customers, particularly given the potential and unwarranted barriers to DA participation it would create.

Additionally, if the Commission is to adopt Staff's preferential curtailment rules, AWEC recommends that existing Long-Term Direct Access ("LTDA") customers be

[4] Existing demand response programs demonstrate that even in the absence of substantial financial penalties, curtailment requests are nearly as effective as direct load control in reducing load and are sufficiently reliable for utilities to incorporate such programs into integrated resource planning.

DAVISON VAN CLEVE, P.C.
1750 SW Harbor Way, Suite 450
Portland, OR 97201
Telephone: (503) 241-7242

grandfathered out of these requirements. These customers left COS with a certain set of financial assumptions that apply under the existing paradigm and there has never been any evidence or circumstance demonstrating that the amount of load currently existing in the utilities' LTDA programs poses a risk to system reliability. It would be fundamentally unfair to materially change their circumstances now, particularly without the evidentiary record to demonstrate whether preferential curtailment is just and reasonable.

B. Caps and BTM Load Growth

Given the "Commission's acknowledgment…that significant distance exists between parties' positions" regarding DA caps, Staff did not initially propose rule language addressing this issue.[5] AWEC supported this decision. However, Staff now asserts that "addressing caps at this phase is important for guiding contested case determinations in the future." [6]

Staff proposes four guidelines for inclusion in this rulemaking that the Commission may consider when determining whether to impose a cap: 1) an increase in DA load that compromises system reliability; 2) an increase in DA load that shifts an unacceptable amount of costs to COS customers; 3) an increase in DA load that poses undesirable long-term financial impacts to COS customers or the electric system; and 4) an increase in DA load that poses other unmitigated risk to COS customers.[7]

---

5 Docket No. AR 651, Staff's Straw Proposal, at 2 (Sep. 2, 2022).
6 *Id.*
7 *Id.* at 3.

DAVISON VAN CLEVE, P.C.
1750 SW Harbor Way, Suite 450
Portland, OR 97201
Telephone: (503) 241-7242

Although AWEC does not inherently take issue with Staff's proposed guidelines, AWEC is nonetheless concerned that inclusion of general guidelines via rule does not advance the discussion of caps given the lack of substantive guidance possible in a rule. AWEC supports discussion of Staff's four criteria guiding the discussion of caps in the contested case phase of this proceeding as that forum would provide meaningful guidance on the development and administration of DA program caps at this stage and, therefore, should not be incorporated into rules at this time.

Regarding updates to potential caps, "Staff proposes that overall DA caps will be recalculated each year, or another regular interval, prior to the annual election window to determine availability under the cap. Caps would be updated to be responsive to the ongoing risks of the program."[8] If caps are implemented through the contested case phase, AWEC supports this policy position and reiterates that any mechanism to recalculate caps should be theoretically based and clearly described in subsequent rules or a Commission order.

C. Non-Bypassable Charges

Although AWEC does not oppose Staff's proposed rule language for OAR 860-038-0170, AWEC nonetheless believes that Staff's previous rule language set forth in Attachment A of Staff's July 7th Report should be adopted because it is more concise and will ensure a consistent application by the Commission. Notably, Staff's previous rule language was an outgrowth of multiple workshops, comment periods, and discussions amongst stakeholders and is therefore a reasonable representation of stakeholders' compromise positions. AWEC

[8] *Id.*

DAVISON VAN CLEVE, P.C.
1750 SW Harbor Way, Suite 450
Portland, OR 97201
Telephone: (503) 241-7242

therefore recommends that OAR 860-038-0170(1)(b) be revised to mirror Staff's previously proposed language as follows: "whether it is an Uneconomic Cost of Implementing a Public Policy Goal or is necessary to implement public policy goals including such as those identified in ORS 469A.465." AWEC also continues to believe that, unless required to be allocated to all customers by statute, only Uneconomic Costs should be allocated to DA customers.

Many costs of implementing public policy goals can be economic and prudent costs even in the absence of the public policy goal. For example, PacifiCorp has found that wind resource additions are economic, and has acquired wind resources to serve load in jurisdictions that do not have renewable resource constraints or other public policy goals related to wind resource acquisition.[9] Economic costs provide a demonstrable benefit to the customers bearing those costs, so requiring DA customers to bear these costs would simply constitute unwarranted cost-shifting to DA load.

III. CONCLUSION

AWEC appreciates the opportunity to comment on Staff's Straw Proposal and looks forward to further engaging with stakeholders on these issues.

Dated this 15th day of September, 2022.

[9] *See* Docket No. LC 70, PacifiCorp's Reply Comments, at 23 (Feb. 5, 2020) ("The most basic objective of the IRP process is to evaluate different ways that PacifiCorp can meet a forecasted need, considering all resource alternatives on a comparable basis. The outcome of this effort in the 2019 IRP, supported by extensive economic and risk analysis, has identified a least-cost, least-risk plan to meet near-term capacity deficits that includes energy efficiency, market purchases, new renewable resources, and new flexible capacity resources.")

DAVISON VAN CLEVE, P.C.
1750 SW Harbor Way, Suite 450
Portland, OR 97201
Telephone: (503) 241-7242

Respectfully submitted,

DAVISON VAN CLEVE, P.C.

/s/ Corinne O. Milinovich
Tyler Pepple
Corinne O. Milinovich
1750 SW Harbor Way, Suite 450
Portland, Oregon 97201
(503) 241-7242 (phone)
(503) 241-8160 (facsimile)
tcp@dvclaw.com
com@dvclaw.com
Of Attorneys for the
Alliance of Western Energy Consumers

Oregon
Kate Brown, Governor

Public Utility Commission
201 High St SE Suite 100
Salem, OR 97301-3398
Mailing Address: PO Box 1088
Salem, OR 97308-1088
503-373-7394

September 1, 2022

AR 651: Division 38 Direct Access Regulation Straw Proposal

Parties to AR 651,

At the public meeting on July 12th, 2022, the Commission determined that certain issues in the AR 651 rulemaking required further detail and policy guidance. Staff has updated its proposed language for Non-bypassable Charges and confidentiality in ESS Emissions Reports, and added rule language on the operationalization of preferential curtailment and provider-of-last-resort responsibilities. Lastly, Staff has included policy positions regarding Direct Access program caps and encourages stakeholders to provide feedback in comments. Staff intends to bring the content in this proposal to the Commission at the October 4th public meeting and appreciates any engagement or feedback from parties. The topics that Staff addressed and the associated rule language are described below:

Non-bypassable Charges, Page 4:

Staff supports certain revisions proposed by NIPPC, CUB, the environmental NGOs, AWEC, and the Joint Utilities to the rule language regarding non-bypassable charges. The language provides clearer criteria to guide contested case determinations and puts clear boundaries around the arguments that can be made about non-bypassability but does not overly restrict consideration of fairness on a cost-by-cost basis.

Default Supply, Provider of Last Resort, Preferential Curtailment, Page 4-6:

Staff believes that preferential curtailment may be the best option to implement the IOU's POLR in many circumstances. Given the state of the energy industry and the difficulty IOUs will face implementing a reliable and just energy transition for their cost-of-service (COS) customers, Staff believes that it is reasonable to adopt policies that encourage Direct Access (DA) customers and Electric Service Suppliers (ESSs) to be responsible for their own reliability. Staff plans to recommend requirements for an ESS to demonstrate resource adequacy (RA) either through participation in a regional RA program or a statewide program in Docket No. UM 2143. With this framework in place, Staff believes that preferential curtailment better balances reliability and efficiency than relying on the IOU to acquire duplicate capacity resources in an increasingly tight market for non-emitting capacity. Staff notes that preferential curtailment would only be enacted when energy is not available on the market and when the utility does not have excess generation capacity. Market purchases or excess generation should be utilized in lieu of preferential curtailment when possible. Any system upgrades required to enable preferential curtailment should be paid for by the respective DA customer or through an agreement with the ESS.

Staff understands that there may be limitations to preferential curtailment relating to cost and system reliability. If it is determined that preferentially curtailing a DA customer is wholly infeasible or will impact system reliability for COS customers, it is reasonable to consider an exemption where the customer must contract with the utility for POLR capacity. To enable this, Staff proposes that the utility would plan capacity for that specific customer, while the customer pays a charge for the capacity investment plus any generation used to serve that customer upon returning in a default scenario. The formula to determine these charges will be determined in the contested case. Rules specifying this curtailment exemption are proposed in 860-038-0290. Specific criteria for exemptions based on a utility's system capabilities and costs can be established in the contested case.

Acknowledging the limitations above, Staff believes that utilities should have the capability to operationalize preferential curtailment given the curtailment requirements for qualifying facilities (QFs), the capabilities of demand response pilots like PGE's Dispatchable Standby Generation, and the deployment of distribution automation investments described in distribution system planning. Staff also sees preferential curtailment in POLR scenarios as consistent with the treatment of natural gas transport customers as outlined in Northwest Natural Gas Company's General Rules and Regulations, Rule 13. While Staff understands the multitude of operational differences between natural gas and electricity service, curtailment of natural gas customers demonstrates that this type of treatment is not unfounded.

Additionally, Staff finds that the issue of preferential curtailment also informs contested case decisions around DA program caps. Staff believes that, in the event caps are set, a regular recalculation could be required to address the changing risk from curtailment-exempt customers.

Please note that in OAR 860-038-0590 on page 7, Staff has included an exclusionary phrase to indicate that the requirements of Section 0590 do not apply in the instance of preferential curtailment. Staff believes this modification is required since the concept of knowingly curtailing one customer over another directly contradicts Section 0590's designation for non-discriminatory access to transmission and distribution for all retail customers.

Confidential Designations in ESS Emissions Planning Reports, Page 6-8:

Staff supports the additions addressing confidential information in the ESS Emissions Planning Reports. The language adds specificity on how parties can access certain categories of information and provides a transparent approach to information sharing via protective order.

Direct Access Program Caps:

Staff did not propose rule language on DA caps at this time based on the Commission's acknowledgment at the July 12th public meeting that significant distance exists between parties' positions and other topics have potential for further stakeholder engagement. However, addressing caps at this phase is important for guiding contested case determinations in the future. Staff has proposed its positions on what rule language could be included, with the intention that parties engage prior to moving to a formal rulemaking.

Staff proposes that the Commission may impose a cap if:

- An increase in DA load compromises system reliability.
- An increase in DA load shifts an unacceptable amount of cost to COS customers.
- An increase in DA load poses undesirable long term financial impacts to COS customers or the electric system.
- An increase in DA load poses other unmitigated risk to COS customers.

The specific amount of increase to DA load, level of risk, and amount of costs that trigger the criteria above can be determined in the contested case phase. Staff believes these guidelines establish how the Commission makes decisions on whether a cap is necessary.

Additionally, Staff reminds parties of the past policy positions on caps and invites feedback:

- To the extent that caps are implemented in a future contested case, Staff proposes that overall DA caps will be recalculated each year, or another regular interval, prior to the annual election window to determine availability under the cap. Caps would be updated to be responsive to the ongoing risks of the program.
- Petitions to exceed a cap will be examined through a 90-day process.
- Behind-the-meter (BTM) load growth can be accommodated provided all risks and cost shifts are addressed through transition charges or RA. A phased approach could address the rate of BTM growth by allowing only a certain percentage of BTM load growth each year.

Lastly, please note the remaining important dates for the informal rulemaking phase below:

September 15th: Deadline for filing written comments on Staff's straw proposal.

October 4th Public Meeting: Staff brings revised rule language and policy positions before the Commission. Request to move to a formal rulemaking.

Staff is not proposing a specific schedule for the contested phase at this time due to the difficulty of grouping and prioritizing issues prior to a Commission determination on the rulemaking. However, Staff is open to parties proposing aspects of the schedule and will engage in those discussions.

Thank you,

/s/ Madison Bolton
Strategy and Integration
503-508-0722
Madison.bolton@puc.oregon.gov

Attachment A: Proposed Division 038 Rules

All additions to the rule language since Staff's previous proposal are in blue font. Staff has only included the sections in the Division 038 rules where new revisions and additions are proposed.

860-038-0170
Non-bypassable Charges

(1) "Non-bypassable Charges" refers to costs that are directed by legislature to be recovered by all customers or determined by the Commission to be associated with implementing public policy goals related to reliability, equity, decarbonization, resiliency, or other public interests.

(2) The Commission will consider whether a charge meets some or all of the following when determining whether it is non-bypassable: ~~are costs that are directed by the legislature to be recovered by all customers or charges that retail consumers served by electricity service suppliers otherwise may avoid by obtaining electric power through direct access that are determined by the Commission to be appropriate for recovery from all customers. In determining whether a cost is appropriate for recovery as a non-bypassable charge, the Commission shall consider the following factors:~~

(a) ~~whether~~ It is required by statute

(b) ~~whether~~ It is an Uneconomic Cost of Implementing a Public Policy Goal or is necessary to implement public policy goals including ~~such as~~ those identified in ORS 469A.465 ~~or similar public policy goals related to reliability, equity, decarbonization, resiliency or other public interest for which retail consumers served by electricity service suppliers otherwise would not meaningfully contribute~~.

(c) ~~whether or not~~ It does not confer~~s~~ a demonstrable electric system benefit on some customers over others

(d) ~~whether~~ It is in the public interest

~~(e) whether it is necessary to be non-bypassable under the Commission's discretion in order to establish fair, just, and reasonable rates.~~

(2) All ~~retail electricity consumers served by~~ Direct Access customers are responsible for paying Non-bypassable Charges as determined by the Commission.

860-038-0280
Default Supply

(1) Default supply is an alternative available to nonresidential consumers served by direct access.

(2) The two types of default supply are emergency as defined in OAR 860-038-0005 and standard offer as defined in OAR 860-038-0250.

(3) Each electric company must provide the emergency option as follows:

(a) Emergency default service commences when an electric company is informed by the ESS or nonresidential consumer, or becomes aware, that an ESS is no longer providing service; and

(b) Each electric company must file tariffs with the Commission that include the emergency service option. An electric company must design emergency service rates to recover its costs of providing such service.

(4) A nonresidential consumer must give the electric company notice of intent to purchase or terminate purchase of standard offer service consistent with the applicable tariff provision.

(5) An electric company may require a deposit from a consumer applying to receive emergency default service or standard offer service. The electric company may disconnect a consumer receiving default service or standard offer service subject to OAR 860-021-0305 and 860-021-0505.

(6) Unless otherwise directed by a nonresidential consumer, an electric company must move an emergency service consumer from emergency default service to standard offer service within five business days of the nonresidential consumer's initial purchase of emergency default service. This provision does not limit a consumer's right to return from emergency default service or standard offer service to direct access.

~~860-038-0290~~
~~Preferential Curtailment~~

~~(1) Except as provided in sections (2) and (5), each electric company shall provide preferential curtailment of nonresidential direct access consumers.~~

~~(2) If an ESS is no longer providing service, the electric company must attempt to serve the returning consumer with market purchases or the electric company's excess generation.~~

~~(a) If served through market purchases or excess generation, the returning consumer will be charged rates for that service as defined in OAR 860-038-0280 (3)(b).~~

~~(3) If an ESS is no longer providing service and market energy or excess generation is not available, the electric company may preferentially curtail returning nonresidential direct access consumers of that ESS.~~

~~(4) The electric company may collect a transition charge from a consumer to recover necessary costs for network and transmission system upgrades that operationalize preferential curtailment of that consumer, using a Commission approved methodology.~~

~~(5) An electric company is exempt from providing preferential curtailment for non-residential direct access consumers if it is infeasible to do so or curtailment would negatively affect the electric system's reliability.~~

~~(a) Where an electric company is exempt from providing preferential curtailment, the electric company will plan for and acquire capacity to account for a direct access consumer's potential return to the electric company's service.~~

~~(b) The electric company will design tariffs to collect charges from the direct access consumer that only recover the costs of the capacity investment and the generation that serves that consumer.~~

860-038-0405
ESS Emissions Planning Report

(1) From the effective date of these rules through May 30, 2027, each ESS certified pursuant to ORS 757.649 that has sold electricity to retail electricity consumers in Oregon in the previous calendar year or has executed a contract to sell electricity to retail electricity consumers in Oregon within the following three calendar years are required to file a copy of the annual greenhouse gas emissions report submitted to the Oregon Department of Environmental Quality in accordance with HB 2021, Section 5(4)(a) within 10 days of filing with the Oregon Department of Environmental Quality.

(2) Beginning on January 1, 2027, each ESS certified pursuant to ORS 757.649 that has sold electricity to retail electricity consumers in Oregon in the previous calendar year or has executed a contract to sell electricity to retail electricity consumers in Oregon within the following three calendar years are required to file a report in accordance with subsection (3) of this rule. If prescribed by the Commission, each ESS must use established forms to provide information required under this rule.

(3) Each ESS must file an Emissions Planning Report on or before June 1st of each calendar year that includes the following:

(a) A cover-page with a checklist for each item required by the report, as set forth in this subsection, and an indication of where that information is found in the report **and whether specified information is confidential subject to a protective order**. A uniform template for the cover page checklist **and Protective Order** will be provided on the Commission website under the Reports & Forms section.

(b) Summary of the specific electricity-generating resources, MWh generation from those resources, emissions per MWh (MTCO2e/MWh) associated with serving Oregon Direct Access customers, and all emissions from the previous calendar year that were reported to DEQ.

(c) Load forecast for each of the following three consecutive years, aggregate for all Oregon Direct Access customers.

(d) An estimate of the annual greenhouse gas emissions associated with serving Oregon Direct Access customers, forecasted for the following three consecutive years.

(e) Action plan that specifies annual goals and resources, including specified and unspecified market purchases, that the ESS plans to use to meet the load and emissions forecast consistent with the DEQ emissions reporting methodology.

(f) An analysis of the $/MWh (levelized if under different pricing structure) that the customer will be charged for service related to compliance for each of the next 3 years.

(g) Anticipated actions to facilitate rapid reductions of greenhouse gas emissions at reasonable costs to retail electricity consumers served by the ESS, including but not limited to:

(i) Development of non-emitting dispatchable resources;

(ii) Demand response offerings;

(iii) Energy efficiency offerings; and

(iv) Onsite renewable generation.

(4) ESS's serving customers or generating electricity in multiple electric company service territories must separate the report's contents referred to in section (3) by each unique service territory.

(5) Commission staff and interested persons may file written comments on each ESS's Emissions Planning Report within 45 calendar days of the filing. The ESS may file a written response to any comments within 30 calendar days thereafter. After considering written comments, the Commission may decide to commence an investigation, begin a proceeding, or take other action as necessary to make a determination regarding HB 2021, section (5)'s requirement for continual and reasonable progress toward compliance with the clean energy targets set forth in section 3 of HB 2021.

(6) Upon conclusion of the Commission review of the report in section (3) of this rule, the Commission will issue a decision to acknowledge the ESS's Emissions Planning Report if it demonstrates continual and reasonable progress toward compliance with clean energy targets. If the Commission determines the Emissions Planning Report does not demonstrate continual and reasonable compliance, the ESS must file an updated Emissions Planning Report that addresses the Commission's concerns within 90 days.

(7) The ESS must post a non-confidential version of the subsection 5(3) report on its website within 30 days of the Commission decision whether to accept the report. The ESS must also provide information about its compliance report to its customers by bill insert or other Commission-approved method.

(8) Availability of Information:

(a) The following information shall be available for review only by Qualified Statutory Parties that have executed a modified protective order:

(i) Information regarding an analysis of the $/MWh (levelized if under different pricing structure) that the customer will be charged for service related to compliance for each of the next 3 years, as required by Section 3(f).

(b) For purposes of this Section, Qualified Statutory Parties means Commission Staff and the Citizen's Utility Board.

(c) The following information shall be available for review only by Non-Market Participants that have executed a modified protective order:

(i) Action plan that specifies annual goals and resources, including specified and unspecified market purchases, that the ESS plans to use to meet the load and emissions forecast consistent with the DEQ emissions reporting methodology, as required in Section 3(e);

(ii) Information regarding the load forecast for each of the following three consecutive years, aggregate for all Oregon Direct Access customers, as required by Section 3(c); and

(iii) The summary of the specific electricity-generating resources and MWh generation from those resources, as required by Section 3(b).

(d) For purposes of this section, Non-Market Participants includes Commission Staff, the Citizen's Utility Board, and non-profit organizations engaged in environmental advocacy that do not otherwise participate in electricity markets.

860-038-0590

Transmission and Distribution Access

(1) An electric company may be relieved of some or all of the requirements of this rule by placing its transmission facilities under the control of a regional transmission organization consistent with FERC Order No. 2000 and obtaining Commission approval of an exemption.

(2) An ESS may request transmission service, distribution service or ancillary services under standard Commission tariffs and FERC-approved tariffs. The electric company shall coordinate the filings of these tariffs to ensure that all retail and direct access consumers are offered comparable services at comparable prices.

(3) **Except as otherwise directed by OAR 860-038-0290**, each electric company shall provide nondiscriminatory access to transmission, distribution, and ancillary services, including transmission into import-limited areas and local generation resources within import-limited areas, to serve all retail consumers. An electric company shall not give preference or priority in transmission and distribution pricing, transmission and distribution access, or access to, pricing of, or provision of ancillary services and local generation resources, to itself or its affiliate relative to persons or entities requesting transmission or distribution access to serve direct access consumers. No preference or priority may be

given to, nor any different obligation assigned to, any consumer based solely on whether the consumer is purchasing service from an electric company or an ESS.

(a) Any transmission or distribution capacity to which an electric company has entitlements, by ownership or by contract, for the purpose of serving its Oregon load shall be made available to an electric company and ESSs that are serving such load on at least a pro rata basis. An electric company shall describe in its tariff filings how it proposes to provide substantively comparable transmission and distribution service to all retail consumers at the same or similar rates if:

(A) Access to the electric company's transmission or distribution facilities or entitlements is restricted by contract or by regulatory obligations in other jurisdictions; or

(B) If providing transmission or distribution service on a pro rata basis would result in stranding generating capacity owned or provided through contract by the electric company;

(b) Except for those ancillary services required by FERC to be purchased from an electric company, an ESS may acquire, on behalf of the retail loads for which it is responsible, all ancillary services required relative to the transmission of electricity by any combination of:

(A) Purchases under the electric company's Open Access Transmission Tariff;

(B) Self-provision; or

(C) Purchases from a third party;

(c) Energy imbalance obligations, including the pricing of imbalances and penalties for imbalances, shall be developed to reasonably minimize imbalances and to meet the needs of the direct access market environment. The electric company shall address such energy imbalance obligations in its proposed FERC tariffs. Energy imbalance obligations imposed upon ESSs, including the entity serving the standard offer load, and consumers purchasing service from the electric company, shall comply with the following:

(A) The obligations shall impose substantively comparable burdens upon ESSs, including the entity serving the standard offer load, and consumers purchasing service from the electric company, and shall not unreasonably differentiate between consumers that are entitled to direct access on the basis of customer class, provider of the service, or type of access;

(B) The obligations shall recognize the practical scheduling and operational limitations associated with serving retail consumer loads in the direct access environment, but shall require ESSs, including the entity serving the standard offer load, to make reasonable efforts to minimize their energy imbalances on an hourly basis;

(C) The obligations shall be designed with the objective of deterring ESSs, including the entity serving the standard offer load, and consumers purchasing service from the electric company from burdening electric system operation or gaining economic advantage by under-scheduling, over-scheduling, under-generating or over-generating. The obligations shall not be punitive in nature; and

(D) The obligations shall enable an electric company and ESSs, including the entity serving the standard offer load, to settle for energy imbalance obligations on a financial basis, unless otherwise mutually agreed to by the parties.

(d) Where local generation is required to operate for electric system security or where there is insufficient transmission import capability to serve retail loads without the use of local generation, the electric company shall make services available from such local generation under its ownership or control to ESSs consistent with the electric company's provision of services to standard offer consumers, residential consumers, and other retail consumers. The electric company shall also specify such obligations in appropriate sales contracts prior to any divestiture of such resources;

(e) The electric company's tariffs shall specify prices, terms, and conditions for scheduling, billing, and settlement. Other functions may be specified as needed;

(f) An electric company's tariffs shall include a dispute resolution process to resolve issues between the electric company and the ESSs that serve the retail load of an electric company in a timely manner. Such processes shall provide that unresolved disputes related to such retail access matters may be appealed to the Commission.

(4) If adherence to OAR 860-038-0590 requires FERC approval of tariff or contract provisions, the electric company must petition FERC for the approval of the tariff or contract provisions within 90 days of the effective date of this rule. Subsequent tariffs or contracts requiring FERC approval will be made in a timely manner.