ITEM NO. 1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: August 25, 2015

REGULAR <u>X</u> **CONSENT** ____ **EFFECTIVE DATE** ____________________

DATE: August 13, 2015

TO: Public Utility Commission

FROM: Ruchi Sadhir J for RS

THROUGH: Jason Eisdorfer J

SUBJECT: <u>OREGON PUBLIC UTILITY COMMISSION STAFF</u>: (Docket No. UM 1690) Voluntary Renewable Energy Tariffs for Non-Residential Customers. Docket opened by HB 4126.

STAFF RECOMMENDATION:

Accept the Voluntary Renewable Energy Tariff (VRET) Study and close Phase 1 of Docket No. UM 1690. Open Phase 2 for parties to file responses on the threshold question in the statute: whether, and under what conditions, it is reasonable and in the public interest to allow electric companies to provide voluntary renewable energy tariffs to nonresidential customers.

DISCUSSION:

<u>Background</u>

House Bill (HB) 4126 (2014 legislative session) directs the Public Utility Commission (PUC or Commission) to conduct a study to consider the impact of allowing electric companies to offer VRETs to their nonresidential customers. See Attachment 1 of the VRET Study for HB 4126. HB 4126 further sets forth public policy factors the Commission is to consider in subsequent phases of implementing HB 4126. Staff conducted the VRET Study through several workshops that set study guidelines, with stakeholder comments and reply comments on an issues list, and by developing VRET models to help consider the impact of VRETs. The attached Phase 1 VRET Study memorializes the study process, stakeholder input, and results to be considered in Phase 2.

Subsequent Phases of UM 1690

Staff anticipates two subsequent phases of UM 1690 to fully implement HB 4126:

- Phase 2. The Commission must consider the results of the VRET Study in conjunction with the five statutory factors (listed below) to determine whether, and under what conditions, it is reasonable and in the public interest to allow electric companies to provide VRETs to nonresidential customers. This determination is considered the "threshold question" for this multiphase docket. In Phase 2, the Commission has the option to decide that VRETs are not reasonable and not in the public interest, which would result in not allowing the electric companies to offer VRETs and close this docket. The Commission also has the option of finding that VRETs are reasonable and in the public interest, potentially with the adoption of certain conditions, which could lead to Phase 3 of this Docket.

- Phase 3. If the Commission determines in Phase 2 to allow electric companies to offer VRETs to nonresidential customers, then, in Phase 3, the Commission may authorize an electric company to file a schedule with the Commission to establish rates, terms, and conditions of services offered under the VRET, subject to any conditions adopted in Phase 2. HB 4126 requires all costs and benefits associated with a VRET to be borne by the nonresidential customer receiving service under the VRET. In determining whether to approve a VRET schedule in Phase 3, the Commission must consider the same five statutory factors (listed below).

Analysis

Phase 1 VRET Study

Staff used the five statutory factors listed in HB 4126 to organize the VRET Study on the impact of allowing electric companies to offer VRETs to their nonresidential customers. Because the Commission is directed to use these statutory factors in subsequent phases of HB 4126, Staff determined that the VRET Study would be more effective through focus on these factors as well. The five statutory factors are:

Statutory Factor (1) Whether allowing electric companies to provide VRETs to nonresidential customers promotes the further development of significant renewable energy resources;

Statutory Factor (2) The effect of allowing electric companies to offer VRETs on the development of a competitive retail market;

Statutory Factor (3) Any direct or indirect impact, including any potential cost-shifting, on other customers of any electric company offering a VRET;

Statutory Factor (4) Whether the VRETs provided by electric companies to nonresidential customers rely on electricity supplied through a competitive procurement process; and

Statutory Factor (5) Any other reasonable consideration related to allowing electric companies to offer VRETs to their nonresidential customers.

The Phase 1 VRET Study is attached. The VRET Study provides information about: (1) HB 4126 background and requirements, (2) stakeholder workshops and public comment, (3) staff-developed study guidelines, (4) existing energy policies and frameworks, (5) VRET Models developed to inform the study, (6) analysis of issues related to statutory factors in HB 4126, (7) analysis of issues related to the threshold question in HB 4126, and (8) results to consider in Phase 2. In addition, there are five attachments to the VRET Study: (1) HB 4126, (2) summary of relevant existing tariffs, (3) summary table of direct access programs, (4) World Resources Institute summary of "green tariffs" being considered across the country, and (5) staff summary of comments received by stakeholders on the Phase 1 issues list.

HB 4126 directs the Commission to consider the results of the study in Phase 2. Staff considered a great deal of input and materials, as evidenced by the attached study and attachments, and makes the following findings, which are followed by key questions for Phase 2.

1. There is not a clear, agreed-upon definition of a VRET, nor does HB 4126 provide a definition or list of attributes of a VRET in Oregon. Staff understands that many stakeholders describe a VRET as a utility offering that allows non-residential customers to voluntarily elect to pay a higher rate than their typical customer tariff because they are seeking renewable energy supply, an ability to make a "green power claim," and/or long-term and less-volatile energy costs. This description permitted a wide range of VRET models offered by stakeholders with differing design features involving system ownership, types of eligible renewable energy resources, load aggregation, utility role in connecting to third party renewable energy suppliers, and use of Qualifying Facilities under PURPA (among others). This wide range of VRET models led to different impacts when

the statutory factors were considered, which raised different policy issues and potential conditions.

2. Considering a wide range of VRET models was a helpful exercise to discover potential issues that may or may not be resolved through conditions. However, it is not necessary to develop a hypothetical, detailed VRET model in order to determine appropriate and reasonable conditions in Phase 2. In addition, it is difficult for staff and stakeholders to answer the threshold question of whether to allow VRETs without also considering potential conditions that would constrain subsequent, more detailed VRET filings in Phase 3. This circular analysis suggests that the threshold question of whether to allow VRETs and potential conditions on VRETs should be answered together to best inform stakeholders, the Commission, and Staff.

3. The key questions, summarized below, that Staff determined through its analysis of the threshold question and statutory factors should be, at a minimum, the focus of Phase 2, which will help to focus parties' responses on the threshold question and potential conditions. Analysis of the statutory factors revealed to Staff that there are significant issues and considerations that could constrain a VRET, including, but not limited to:

   - *Furthering Development of Significant Renewable Energy Resources*: Tailored REC-based products are already available under existing utility tariffs and may fulfill the needs of some non-residential customers interested in making a green power claim through a utility green energy product, but a tailored REC-based product may not be sufficient to be a VRET.

   - *Preventing Cost Shift to Non-Participating Customers*: VRETs must prevent cost shifting (strictly prohibited in HB 4126), which implies the need for the accounting of utility system costs similar to transition adjustments in direct access programs and limits the utilities' options in designing a VRET that is attractive to those nonresidential customers seeking a low-cost green power product.

   - *Effect on Competitive Retail Market*: While HB 4126 allows that the Commission's policies to eliminate barriers to competitive retail markets does not bar approval of a VRET, negative impacts to the competitive marketplace and fairness concerns may require a level playing field between a VRET and direct access programs.

Key Phase 2 Questions about VRET Conditions

Staff's consideration of each statutory factor in the attached VRET Study included key points of analysis and key questions, which could lead to conditions, to consider in Phase 2. Staff suggests that, at a minimum, parties' responses in Phase 2 address these questions.

Furthering Development of Significant Renewable Energy Resources

1. What conditions, if any, should be applied to a VRET in order to promote further development of significant renewable energy resources (e.g. resource age limitations, resource geographic limitations, use of Renewable Portfolio Standard (RPS) for definitions or baseline, etc.)?

2. Are there unbundled Renewable Energy Credit (REC) (as defined in Oregon's RPS laws) only products, which do not include the electricity associated with the REC, that would promote further development of significant renewable energy resources?

Effect on the Competitive Retail Market

3. Should a VRET condition require parity between VRET requirements and direct access requirements (e.g. transition adjustment, participation cap, election windows, etc.)?

Effect on the Competitive Retail Market & Preventing Cost Shift to Non-Participating Customers

4. In order to prevent the potential for negative effects on the competitive retail market and cost-shifting to non-participating customers, should a VRET condition not allow a regulated utility to own a renewable resource for VRET service energy supply?

Preventing Cost Shift to Non-Participating Customers

5. Should a VRET condition require identification of all potential costs, risks, and mitigation measures and require demonstration that all direct and indirect impacts to nonparticipating customers are prevented?

Reliance on a Competitive Procurement Process

6. Should a VRET condition require the use of a competitive procurement process if certain triggers are present (e.g. utility ownership of a VRET resource or aggregation of resources for subscription), and, if so, what triggers would require the need for a competitive procurement process?

Any Other Reasonable Consideration

7. Should a VRET condition require the use of third party renewable energy verification?

Key Phase 2 Questions about Threshold Question

Given the public policy issues in each statutory factor discussed above that should be resolved through VRET conditions, the Commission must decide whether it is reasonable and in the public interest to allow utilities to offer a VRET in the first place. As used in Section 3(2) of HB 4126, Staff's counsel advises that the meaning of the phrase "is reasonable and in the public interest" is informed by the five factors set forth in Section 3(2)(a)-(e).[1] In Phase 2, the Commission will need to weigh these five factors and conclude whether it is reasonable and in the public interest to allow VRETs to be offered by utilities to nonresidential customers. In Staff's view, the Commission's public interest inquiry should include the following considerations:

1. Whether it is reasonable and in the public interest to allow utilities to provide nonresidential customers with an additional renewable energy product choice because those nonresidential customers do not have sufficient options for renewable energy products through existing policies?

2. Whether it is reasonable and in the public interest for regulated utilities to be able to offer a new renewable energy product choice that is valuable to customers because there are benefits in the regulated utility making such an offering?

3. Whether it is reasonable and in the public interest to create a VRET program that is only available and accessible to a limited customer base, which involves administrative burden on Staff and a broad range of stakeholders, to allow utilities to offer a product that they may already be able to offer by forming an affiliate through direct access?

[1] Generally, Commission orders interpreting the meaning of "in the public interest" are specific to the statute at issue in that proceeding. For example, in the context of utility mergers, "public interest" under ORS 759.375 means there is "no harm" to the public if the merger is allowed. *See* Order No. 09-169. But, in the context of an entity acquiring a utility, "public interest" under ORS 757.511 means there must be "net benefits" to the public if the acquisition is allowed. See Order No. 06-082. In the context of ORS 757.415(2)(b) (purposes for which securities and notes may be issued), the Oregon DOJ has opined that "compatible with the public interest" is explained by the context of the other language/factors/criteria set forth in that particular statutory section.

Phase 2 Process

Staff received feedback from several stakeholders that Phase 2 should be held in abeyance until a joint stakeholder developed model is filed, which would re-open the docket. However, after further consultations, stakeholders withdrew this suggestion because stakeholders recognized that a single VRET model should not be used as the basis of deciding whether any VRET could be offered.

On the other hand, staff and parties have found it difficult to answer the threshold question of whether any VRET should be allowed to be offered without a VRET definition or VRET design. The public interest context and analysis of the five statutory factors and potential conditions would best inform responses to the threshold question: whether, and under what conditions, it is reasonable and in the public interest to allow electric companies to provide voluntary renewable energy tariffs to nonresidential customers. Even though there are two subparts of the threshold question, in essence, there is one question asking whether the public interest benefits of offering a VRET outweighs the costs of implementing necessary conditions to that VRET. In addition, answering the two subparts of the threshold question in isolation or in sequence may unnecessarily elongate an already long process because there may be duplication in answers.

Therefore, staff recommends that the Phase 2 process consist of briefs or comments that address threshold question. Staff envisions two rounds of simultaneous briefs/comments in a defined schedule set by an Administrative Law Judge. Staff also suggests that testimony may not be necessary in Phase 2 because there does not appear to be evidentiary issues of fact.

PROPOSED COMMISSION MOTION:

Accept the VRET Study and close Phase 1 of Docket No. UM 1690. Open Phase 2 and direct the electric companies and interested parties to submit filings that address the threshold question in the statute: whether, and under what conditions, it is reasonable and in the public interest to allow electric companies to provide voluntary renewable energy tariffs to nonresidential customers.

UM 1690 PHASE 1 VRET STUDY

Staff conducted the UM 1690, Phase 1 Study of Voluntary Renewable Energy Tariffs (VRET) with stakeholders between June 2014 and July 2015. Here, Staff provides information about: (I) HB 4126 background and requirements, (II) stakeholder workshops and public comment, (III) staff-developed study guidelines, (IV) existing energy policies and frameworks, (V) VRET models developed to inform the study, (VI) analysis of issues related to statutory factors in HB 4126, (VII) analysis of issues related to the threshold question in HB 4126, and (VIII) results to consider in Phase 2. In addition, there are five appendices: (1) HB 4126, (2) summary of relevant existing tariffs, (3) summary table of direct access programs, (4) World Resources Institute summary of "green tariffs" being considered across the country, and (5) Staff summary of comments received by stakeholders on the Phase 1 issues list.

I. Background

House Bill (HB) 4126 (2014 legislative session) directs the Public Utility Commission (PUC or Commission) to conduct a study to consider the impact of allowing electric companies to offer VRETs to their non-residential customers. The law requires the study to be subject to public comment in a manner determined by the Commission. HB 4126 further sets forth public policy factors the Commission is to consider in subsequent phases of implementing HB 4126. *See* Appendix 1 for HB 4126. Staff conducted this VRET study through several workshops that set study guidelines, with stakeholder comments and reply comments on an issues list, and by developing VRET models to help consider their impacts.

A. Study Organization around Five Statutory Factors

In this Phase 1 study, Staff used the five statutory factors listed in HB 4126 to organize the study on the impact of allowing electric companies to offer VRETs to their non-residential customers. Because the Commission is directed to use these statutory factors in subsequent phases of HB 4126, Staff determined that the study would be more effective through focus on these factors as well. In addition, the statutory factors drove the development of the issues list. The five statutory factors are:

(1) Whether allowing electric companies to provide VRETs to non-residential customers promotes the further development of significant renewable energy resources;

(2) The effect of allowing electric companies to offer VRETs on the development of a competitive retail market;

(3) Any direct or indirect impact, including any potential cost-shifting, on other customers of any electric company offering a VRET;

(4) Whether the VRETs provided by electric companies to non-residential customers rely on electricity supplied through a competitive procurement process; and

(5) Any other reasonable consideration related to allowing electric companies to offer VRETs to their non-residential customers.

II. Phase 1 Workshops and Public Comment

Phase 1 of this docket involved public comment and three stakeholder workshops regarding VRET statements of principles, development of study guidelines, VRET models, and a draft issues list. Finally, Staff requested public comments and reply comments on VRET models and answers to the questions in the final issues list.

The first workshop on June 2, 2014, primarily involved an overview of HB 4126 and discussion of the suggested process to implement the bill. The second workshop on June 23, 2014, included a panel of potential customers[1] and a panel with PGE, PacifiCorp, and World Resource Institute (WRI) to discuss the need for a VRET, along with discussion about comments on statements of VRET principles. The third workshop was on August 12, 2014. It involved discussion about the study guidelines, VRET models developed by Staff, and refinements to the issues list. In general, stakeholder perspectives and views about VRET statements of principles and development of study guidelines, VRET models, and the issues list were provided to staff throughout workshops and written comments.

On November 7, 2014, Staff requested public comment on the VRET models and answers to the questions in the final issues list. Comments were received on December 12, 2014, by Iberdrola Renewables LLC (Iberdrola), Renewable Energy Markets Association (REMA), Renewable Northwest (RNW), PGE, Shell Energy (Shell), WRI, Your Access to Marketing Services (YAM), Center for Resource Solutions (CRS), PacifiCorp, Northwest & Intermountain Power Producers Coalition (NIPPC), Industrial Customers of Northwest Utilities (ICNU), Noble Americas Energy Solutions LLC (Noble), Citizens' Utility Board (CUB), and Oregon Department of Energy (ODOE). Reply comments were received on January 9, 2015, by Obsidian, PGE, RNW, ICNU,

[1] The "potential VRET customer" panel included CH2MHill, Facebook, City of Hillsboro, Oregon Military Department – Oregon National Guard, City of Portland, Staples, and Walmart. Staff notes that there were several other customers that were interested in a VRET, but were not able to be panel participants in a public workshop setting.

PacifiCorp, CUB, Noble, and NIPPC. Obsidian also provided comments regarding a straw proposal on February 9, 2015.

III. <u>Development of Study Guidelines</u>

Through the workshops, Staff and workshop participants found it difficult to discuss impacts of a VRET because there was no clear definition of a VRET in HB 4126. Staff determined that it was important for workshop participants to have a common understanding of how a VRET could be designed in order to study impacts of a VRET. Staff adopted three guidelines (Guidelines) to keep the study focused and help achieve a better understanding of potential VRETs that could help discover impacts of allowing VRETs for non-residential customers. The three Guidelines are that VRET models should be: (1) new and not currently available, (2) not duplicative of another model, and (3) likely to be offered by the regulated utility.

For its first Guideline, Staff decided that the study should concentrate its review on potential utility renewable service offerings that were new, meaning not clearly permitted prior to the enactment of HB 4126. This Guideline arose out of the workshops in which some stakeholders advocated broadening the study to include service offerings that were allowed under pre-existing law. Staff reasoned that its first Guideline was necessary to keep the Study on track and not become overwhelmed or over-burdened with the review of numerous non-VRET offerings (stakeholders referred to existing or potential service offerings as "models" to be studied). This is not to say that offerings or models that were allowed under pre-HB 4126 law were not discussed. They are important for background and context to a potential VRET offering (*See* subsequent "Existing Energy Policies and Frameworks" section). However, the Guideline was intended to ensure that the majority of the study effort was directed to the in-depth review of possible VRET offerings.

Staff notes that its first Guideline is consistent with the language of HB 4126, which expressly directs the Commission to study the impact of utility-offered VRETs. Staff's counsel further advised that a fair reading of HB 4126 is that it was enacted to permit a type of service offering by an electric utility that was not clearly allowed by the then existing law.[2] As such, it is reasonable for the study to focus its energies on the review of such newly-permitted service offerings.

[2] *See*, e.g., International Ass'n of Fire Fighters, Local 3564 v. City of Grants Pass, 262 Or App 657 (2014) (Courts presume that when the legislature enacts a statute, it does so with full knowledge of the existing condition of the law and with reference to it); Matter of Marriage of Greenfield, 130 Or App 632 (1994) (In enacting legislation, legislature's awareness of existing law is presumed).

For its second Guideline, Staff determined the study should not consider VRET models that were duplicative of each other. This principle arose out of workshops in which some stakeholders proposed models that, while differing in minor details, essentially were identical to a model proposed by another party.

For its third and last Guideline, Staff decided to limit the study to VRET models that "were likely to occur." Staff's third Guideline is consistent with the specific HB 4126 language "allowing" a utility to voluntarily "offer" VRETs to non-residential customers. This Guideline arose because during the workshops some stakeholders desired to have the study consider models that the utilities expressly stated they would not offer.[3]

Through these guidelines, workshop discussion, and stakeholder comments, Staff developed and refined several VRET models that were referenced in the issues list as a concrete way to conduct the study to "consider the impact of allowing electric companies to offer VRETs to their non-residential customers" as required in HB 4126.

IV. Existing Energy Policies and Frameworks

To help envision a VRET fitting in the Oregon energy landscape, Staff and workshop participants needed background and context on existing energy policies and frameworks as part of the study. This context was important, in particular, because of Staff's first Guideline that focused VRET models on those that were new and not permitted prior to the enactment of HB 4126. Several workshop participants asserted that this contextual information was a necessary precursor to the study, and Staff agreed to include this contextual information in this memo. Staff provides the following brief descriptions of existing energy policies and frameworks in Oregon that are relevant to the study of a VRET. Staff has also provided a list and brief description of existing IOU tariffs relevant to VRET discussion in Appendix 2.

[3] Staff notes that NIPPC has argued the "voluntary" nature of a VRET refers to the option of customers to take VRET service, not whether the utilities could choose to offer it. NIPPC points to legislative history for support of this interpretation. In HB 4126 public hearing testimony (House Committee on Energy & Environment, February 6, 2014), legislative counsel analogizes the VRET for nonresidential customers to the voluntary renewable energy programs for residential customers (such as the PacifiCorp "Blue Sky" option or the PGE "Green Source" option), which the utilities are required to offer as part of a "portfolio of options." *See* ORS 757.603(2)(a) [SB 1149 (1999)]. After consideration of the express language of HB 4126, and application of relevant rules of statutory interpretation, Staff's counsel advised that while an electric company has the option of providing a VRET, it is not required to do so. Thus, Staff created its "likely to occur" Guideline in order to limit VRET models to only those that a utility would be likely to propose.

A. Utility Direct Access Programs.

Direct Access programs should be considered as part of the implementation of VRETs because of the second statutory factor, requiring the Commission to consider effects on development of competitive retail markets. PGE and PacifiCorp were required to establish a direct access program pursuant to SB 1149 (1999). Codified sections related to the direct access law are found in ORS 757.600 through ORS 757.691. Division 038 implements the direct access law at OAR 860-038-0001 through 860-038-0640. HB 4126 Section 3(5) specifically states that rules adopted under ORS 757.646 (1) and 757.659 (7) pursuant to ORS 757.646 (1), which require the Commission to develop policies to eliminate barriers to competitive retail markets, do not bar the Commission from approving a schedule for a VRET that is otherwise consistent with HB 4126 and its findings.

SB 1149 mandated that IOUs make changes in their provision of electric service. Idaho Power Company has been exempt from these requirements because of their smaller size in Oregon.[4] Pursuant to the implementation of SB 1149, PGE and PacifiCorp established direct access programs for energy supply and to provide transmission access (through a FERC approved Open Access Transmission Tariff (OATT)), while distribution services continued to be provided by each utility.

Through direct access, non-residential customers have the ability to purchase electricity from a provider other than their current utility. An alternative energy provider is called an Electricity Service Supplier (ESS). The PUC must certify each ESS and maintain a list of certified ESSs. If a non-residential customer chooses direct access, the supply mix and environmental impact of the energy from an ESS depends on the non-residential customer's agreement with the ESS. The rate a non-residential customer pays for energy from an ESS would be based on the terms negotiated with the ESS.[5] In addition, there are several constraints and charges that are required in direct access. For example, non-residential customers may only sign up for direct access during specified election windows and there are limitations related to customer load sizes, caps on participation, and partial requirements service. Also, direct access customers are required to pay a charge or receive a credit for a transition adjustment. A transition

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[4] See OAR 860-038-0001 (". . . except that these rules do not apply to an electric company serving fewer than 25,000 consumers in this state. . . "). According to the Oregon Statistics book, Idaho Power Company had 18,490 Oregon customers in 2013. See 2013 Oregon Utility Statistics Book, *available at*, http://www.puc.state.or.us/docs/statbook2013.pdf .

[5] Note that both the utilities and ESSs must report price information for nonresidential customers in accordance with OAR 860-038-0300 (Electric Company and Electricity Service Suppliers Labeling Requirements).

credit or transition charge is 100 percent of the net value of the Oregon share of all economic utility investments and all uneconomic utility investments of the electric company (OAR 860-038-0160).

Each year, PGE and PacifiCorp file with the PUC to update the net power costs for the year and set a transition adjustment for Oregon customers that choose direct access during an election window. In this filing, PacifiCorp and PGE re-calculate their transition charges or credits through a complex methodology to determine the utility's stranded costs or benefits in a process called ongoing valuation (OAR 860-038-0140). At a minimum, the ongoing evaluation method must address:

(1) How and over what period the electric company proposes to establish the fixed costs of included generating resources;
(2) How and over what period the electric company proposes to establish the variable costs of included generating resources;
(3) How and over what period the electric company proposes to establish the availability and output of included generating resources;
(4) How and over what period the electric company proposes to establish the market value of the output of included generating resources; and
(5) How and when revisions should be made in the method.

A recent PacifiCorp docket provides an illustrative example of the types of issues that arise in direct access related matters. As required under Order No. 12-500 in UM 1587 (Investigation of Issues Relating to Direct Access) PacifiCorp filed a revised PacifiCorp tariff for a transition adjustment and five year cost of service opt-out. This revised tariff was considered in UE 267. Prior to 2015, PacifiCorp had four options for commercial and industrial customers that are eligible for direct access: 1) one-year direct access program, 2) three-year direct access program, 3) market indexed rates, and 4) cost of service rates. PGE's options are similar, except PGE also offered customers a five-year direct access program tariff prior to 2015. To illustrate the types of issues that arise in direct access related matters, major issues discussed in Order No. 15-060 (entered into Docket No. UE 267) included:

(1) Rate components and protection against cost-shifting, including delivery charges, generation fixed costs, a transition adjustment, and a consumer opt-out charge,
(2) Transition adjustment calculation using the value of the electricity that is freed up when a customer chooses to leave cost-based supply service and the regulated net power costs of the utility,
(3) Total load that would be eligible for this tariff (determined to be 175 aMW),
(4) Eligibility for this tariff, including whether consumers could aggregate meters on the same property to meet an eligibility load threshold,

(5) Tariff election window and the timing for interested customers to sign up, and
(6) Right to return to cost of service rates and associated advance notice requirements.

Issues and dockets related to direct access have been complex since the program's inception in 1999. In an effort to highlight of the current status of direct access, Staff has summarized PGE's and PacifiCorp's direct access programs in a table in Appendix 5.

B. <u>Oregon Renewable Portfolio Standard (RPS)</u>.

The Oregon RPS should be considered as part of the implementation of VRETs because of the first statutory factor, requiring the Commission to consider further development of renewable energy. In addition, HB 4126 Section 3(6) specifically states that any electricity procured by the utility for VRET service may not be used by the utility to comply with its RPS requirements. SB 838 was passed in 2007 to establish an RPS with specific targets for utilities to procure renewable energy. Codified sections related to the RPS are found in ORS 469A.005 through ORS 469A.300. Division 083 of OAR implements the RPS law at OAR 860-083-0005 through 860-083-0500.

The RPS requires Oregon utilities to deliver a percentage of their electricity from renewable resources by 2025. For Oregon's three largest utilities, PGE, PacifiCorp, and Eugene Water and Electric Board, the standard started at 5 percent in 2011, increased to 15 percent in 2015, and increases to 20 percent in 2020 and 25 percent in 2025. Idaho Power Company and other smaller utilities have different standards depending on their size. An ESS must meet the requirements of the RPS that are applicable to the electric utilities that serve the territories in which the ESS sells electricity to retail electricity consumers (ORS 469A.065). There are several requirements and limitations in complying with the RPS, for example:

- *RPS Eligible RECs*: A renewable energy credit (REC) is a unique representation of the environmental, economic, and social benefits associated with the generation of electricity from RPS-eligible renewable resources (OAR 330-160-0015 (15)). One REC is created in association with the generation of one MWh of electricity from a RPS-eligible renewable resource. RECs generated from eligible renewable resources, including biomass, geothermal, hydropower, ocean thermal, solar, tidal, wave, wind, and hydrogen, are typically used to comply with the RPS. RECs from biomass and hydropower resources have conditional limitations for use in compliance with the RPS.

- *RPS Compliance with Bundled RECs*: A REC becomes a "bundled REC" when the REC is acquired by a utility or ESS by a trade, purchase, or other transfer of electricity that includes the REC that was issued for that electricity. In practice, this bundling has been demonstrated when power and its associated REC are purchased in the same transaction or when the utility has owned the renewable resource that generated the electricity and its associated REC, assuming that those RECs are not sold to a third party. Bundled RECs may be used to comply with the RPS if the renewable resource is located in the U.S. and within the Western Electricity Coordinating Council (WECC) geographic boundary and the electricity from the renewable resource is delivered to BPA, the utility's transmission system, or another delivery point designated by the utility for subsequent delivery to the utility (ORS 469A.135).

- *RPS Compliance with Unbundled RECs:* An unbundled REC means the environmental attributes from a renewable resource that has been acquired by a utility or ESS by trade, purchase, or other transfer without acquiring the electricity for which the REC was issued. Unbundled RECs may be used to comply with the RPS if the renewable resource that generates the unbundled REC is located within the geographic boundary of the WECC (ORS 469A.135). Unbundled RECs, including banked unbundled RECs, may not be used to meet more than 20 percent of the RPS requirements for PGE's and PacifiCorp's targets, which is a requirement of the large utility RPS (5 percent in 2011, to 15 percent in 2015, 20 percent in 2020, and 25 percent in 2025). This unbundled REC limitation does not apply to RECs generated through a net-metered facility (ORS 757.300), generating facilities that are not directly connected to a distribution or transmission system, and qualifying facilities under PURPA (ORS 469A.145). Any consumer owned utilities subject to the large utility RPS may use unbundled RECs to meet up to 50 percent of its RPS target until 2020 or more than 50 percent for consumer-owned utilities and compliance years that fall within Section 2 of HB 4126. This limitation on the use of unbundled RECs does not apply to RPS requirements for ESSs. ESSs may meet their RPS targets entirely through the use of unbundled RECs.

- *RPS Compliance with Banked RECs*: A banked REC is a bundled or unbundled REC that is not used by a utility or ESS to comply with its RPS in a calendar year and that is carried forward for compliance with its RPS in a subsequent year (ORS 469A.005(1)). Both bundled and unbundled RECs with a vintage of January 2007 or later may be "banked" and held for future use to comply with the RPS (OAR 330-160-0030(3)).

- *RPS Compliance Exemption*: Compliance with the RPS is not required if it would require the utility to acquire electricity in excess of the utility's projected load requirements in any year and acquiring the additional electricity would require the utility to substitute qualifying electricity for electricity derived from an energy source other than coal, natural gas, or petroleum (ORS 469A.060).

- *RPS Compliance Cost Limits:* Utilities are not required to comply with the RPS during a compliance year to the extent that the incremental cost of compliance, the cost of unbundled RECs, and the cost of alternative compliance payments exceeds four percent of the utility's annual revenue requirement for that compliance year (ORS 469A.100).

The Western Renewable Energy Generation Information System (WREGIS), which allows issuance, transfer, and use of RECs in electronic form, is used to establish compliance with the RPS. PGE and PacifiCorp are required to submit an implementation plan to the PUC for meeting the requirements of the RPS in accordance with ORS 469A.075.

- *PGE's RPS Plan*: In its 2013 RPS plan, PGE stated that it would meet its RPS requirement of 20 percent renewable energy by 2020 in the years 2015 through 2019 with bundled RECs that will have been banked between 2009 and 2015.[6]

- *PacifiCorp's RPS Plan:* In its 2013 RPS plan, PacifiCorp stated that it would meet its RPS requirement of 20 percent renewable energy by 2020 in the years 2015 through 2019 with a combination of both bundled RECs and unbundled RECs that will have been banked between 2007 and 2019.[7]

C. <u>Qualifying Facilities (QFs) under Public Utility Regulatory Policies Act (PURPA)</u>

QFs under PURPA should be considered as part of the implementation of VRETs because of the first statutory factor, requiring the Commission to consider further development of renewable energy. In addition, VRET models building on existing QF policies were discussed by stakeholders (*See*, e.g., Obsidian Renewables Straw Proposals for Supplemental Green Tariff).

In response to the energy price shocks of the early 1970s, the U.S. Congress passed PURPA with the intent of encouraging efficient production of electricity by non-utility

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[6] *See* PGE 2013 Renewable Portfolio Standard Implementation Plan, Attachment A ("Tab 3 – Annual Compliance by Resource") available at http://www.oregon.gov/energy/RENEW/RPS/docs/2013%20PGE%20RPS%20Implementation%20Plan.pdf

[7] *See* PacifiCorp's Renewable Portfolio Standard Implementation Plan 2015-90218 Compliance Filing, Attachment A - Accounting of the RECs applicable to the RPS in Oregon, available at http://www.oregon.gov/energy/RENEW/RPS/docs/2013%20Pacific%20Power%20RPS%20Implementation%20Plan.pdf

generators. The law encourages industrial waste heat recovery and renewable resource development by small, non-utility power producers called QFs.

FERC implemented this law and promulgated rules that require electric utilities to connect with and purchase all power made available by a QF in the utility's service territory. The purchase rates that the utility must pay the QF approximates the power procurement costs the utility can avoid as a result of purchasing the power from the QF. FERC rules provide flexibility to individual states to determine QF power purchase prices and the terms and conditions of a power purchase agreement between a utility and a QF. *See* Appendix 2 for tariffs that are relevant to QFs.

D. Voluntary Green Energy Programs for Residential Customers.[8]

Voluntary Green Energy Programs for residential customers should be considered as part of the implementation of VRETs because of the first statutory factor, requiring the Commission to consider further development of renewable energy. In addition, some stakeholders have stated that there may be value in consistency between Voluntary Green Energy Programs for residential customers and Voluntary Green Energy Programs for non-residential customers like a VRET.

SB 1149 was passed in 1999, requiring PGE and PacifiCorp to offer a portfolio of voluntary options to residential customers. Small non-residential customers may also participate in these programs. Currently these programs are implemented through retirement of RECs in WREGIS and by supporting renewable energy projects. Codified sections related to the portfolio of voluntary options are found in ORS 757.601, 757.603, and 757.607. The requirement to offer a portfolio of voluntary options is implemented at OAR 860-038-0005 through OAR 860-038-0220.

SB 1149 directed the Commission to establish a "portfolio of rate options" for residential customers within the electricity provider, including a market-based rate and a rate that reflects significant new renewable energy resources. A recent amendment in HB 2941 Section 1 (2015) also allows a rate option for electricity associated with a specific renewable energy resource, including solar photovoltaic energy.

The Portfolio Options Committee (POC) was established as an advisory group to the PUC and first met in 2002. The group's chief responsibility is to submit

[8] For additional information about the residential green programs see Portland General Electric Green Power at https://www.portlandgeneral.com/renewables_efficiency/renewable_energy/home/default.aspx, PacifiCorp Blue Sky Renewable Energy at https://www.portlandgeneral.com/renewables_efficiency/renewable_energy/home/default.aspx, and the Portfolio Options Committee at http://www.puc.state.or.us/Pages/electric_restruc/indices/pac.aspx .

recommendations annually to the Commission regarding a set of product and pricing options for small commercial and residential customers of PGE and PacifiCorp. The POC charter was established in May 2013 in response to a series of requests from the Commission. In its charter, the POC has stated that when reviewing existing and proposed portfolio option products, the POC's goals are to support: renewable energy and carbon offset markets, growth in participation rates at reasonable costs, high-quality consumer education, and valuable and reasonable rate options for customers.[9]

- PGE currently offers its residential and small non-residential customers:
    - "Green Source" adder option of $0.008/kWh to all of a customer's monthly usage, which is used to buy RECs and for funding development of renewable energy projects,
    - "Clean Wind" adder option of $2.50 per 200kWh unit, which is used to buy RECs and for funding development of renewable energy projects, and
    - "Habitat Support" adder of $2.50 per month that can be included with either option.

- PacifiCorp currently offers its residential and small non-residential customers:
    - "Blue Sky Usage" adder option of $0.0105/kWh to all of a customer's monthly usage, which is used to buy RECs and for funding development of renewable energy projects,
    - "Blue Sky Block" adder option of $1.95 per 100kWh unit, which is used to buy RECs and for funding development of renewable energy projects, and
    - "Blue Sky Habitat" adder of $0.0105/kWh with a $2.50 monthly donation that can be included with either option.

- Idaho Power Company currently allows customers to designate their level of participation by choosing a fixed dollar per month amount, which is added to the customer's regular monthly service charges. Note that the Idaho Power Company program offerings are not included in the SB 1149 POC review because Idaho Power Company is exempt due to their smaller size in Oregon.[10] Funds collected by Idaho Power Company are used to purchase green energy products including:
    - planting an acre of trees for $4.00/month,
    - a year's worth of vehicle emissions for $6.50/month,
    - an average home's yearly electricity use for $9.00/month, and
    - just over 10 tons of carbon dioxide from our air for $10.00/month.

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[9] Portfolio Options Committee, Charter, available at http://www.puc.state.or.us/electric_restruc/purpose/POC_Charter_Final_May_2013.pdf

[10] See Footnote 4.

In addition, PGE recently introduced a new voluntary option through Advice No. 15-10. PGE proposed a Solar Option tariff under which PGE purchases RECs from a solar QF to retire on behalf of customers that elect service by purchasing a kW "share" of the solar project's capacity under the Solar Option tariff. At the time of this writing, this new option is undergoing review of marketing materials by the POC to ensure that messages are not confusing to consumers. This marketing materials review was important because of a potential future voluntary option involving community solar, with which confusion may arise due to different definitions or expectations of community solar. The PUC has opened Docket No. UM 1746 to study and develop a recommendation for a voluntary community solar program design by November 1, 2015, at the request of the legislature in HB 2941, Section 3.

E. Existing Competitive Bidding Guidelines

The Commission's competitive bidding guidelines should be considered as part of the implementation of VRETs because the fourth statutory factor requires the Commission to consider whether energy supplied through a VRET should be subject to a competitive procurement process. Competitive procurement of VRET energy supply could be distinct from or similar to existing Commission guidelines. For context, in UM 1182, the Commission adopted revised guidelines in Order No.14-149, which involve 13 guidelines related to competitive procurement. Under these guidelines, a utility must issue a request for proposal using an Independent Evaluator for all major resource acquisitions (duration greater than five years and quantities greater than 100 MW) identified in its last acknowledged Integrated Resource Plan (IRP). The guidelines include explicit direction to the Independent Evaluator to consider seven risk items for comparing the acquisition of a utility-owned resource to purchasing power from an independent power producer (IPP). The utilities file an application with the Commission seeking acknowledgment of their final shortlist of bidders that result from the competitive bidding process.

F. Net Energy Metering.

Net Energy Metering policies should be considered as part of the implementation of VRETs because of the first statutory factor, requiring the Commission to consider further development of renewable energy. In addition, VRET models involving customer ownership were discussed by stakeholders in workshops. Those types of VRETs would need to be distinguished from net metering, which allows customers that develop renewable energy projects on-site to sell that energy to the utility at the retail rate. The codified sections related to net metering are found in ORS 757.300 and implemented at OAR 860, Division 039.

Net metered energy is the difference between the electricity supplied by the utility and the electricity generated by an eligible customer-generator and fed back to the electric grid over the applicable billing period, which is typically monthly. This means that the utility buys energy through net metering at the same retail rate that the customer pays. Since 1999, Oregon has required all Oregon electric utilities to provide net metering for the output from solar PV panels installed on homes and small businesses. Oregon law limits the size of individual net metering systems to 25 kilowatts, unless the PUC elects to set a higher limit for systems in the service areas of PGE, PacifiCorp, and Idaho Power. The PUC has a 25 kilowatt capacity limit for residential systems and two megawatt limit for non-residential systems. Oregon law authorizes the Commission to limit the cumulative generating capacity of net metered systems in a utility's service territory, but, to date, the Commission has taken no action to cap the total capacity of net metered systems for either utility.[11]

- Through 2013, about 7,000 net-metered systems have been installed in Oregon. These systems have a total capacity of about 42 megawatts.
- About 6,000 net-metered systems are residential systems and about 1,000 net-metered systems are non-residential systems.
- A little under 1,000 systems were installed in the service areas of Oregon's consumer-owned utilities. The rest were installed in the service areas of PGE, PacifiCorp, and Idaho Power Company.

[11] See Investigation into the Effectiveness of Solar Programs in Oregon Report to the Legislature, 5-6 (July 2014), available at http://www.puc.state.or.us/electric_gas/Solar%20Report%202014.pdf

V. VRET Models

The intent behind developing models was not for the Commission to choose a particular model. Rather, it was to discover a range of VRET options that would spur creativity among stakeholders to inform discussion about challenges and issues that may arise with a VRET and therefore what conditions may be necessary in a VRET. Staff emphasizes that the Commission is not directed to choose a VRET model in HB 4126. In Phase 2, the Commission will determine whether, and under what conditions, it is reasonable and in the public interest to allow electric companies to provide VRETs to non-residential customers.

The following models were developed by Staff through workshop discussion. Interested stakeholders provided written comment in the development of these models to describe the VRET resource owner, role of the utility, and relationships with other parties in a transaction for each model. In addition to VRET models, the existing direct access program was described first to compare it to VRET models.

1. Workshop: Existing Direct Access Comparison to potential VRET Models – ESS contracts with non-residential customer to sell electricity services. ESS schedules energy to regulated utility, which delivers the energy to the customer through the distribution system. ESS could provide back-up/supplemental (firming/shaping) services, or may not; instead those services may be provided by the regulated utility. An aggregator may combine customer loads into a buying group for purchase of electricity and related services.

2. Workshop Model 1(b/x) Third Party Owned & Regulated Utility Facilitated – Third party owned renewable resource. Regulated utility facilitates between a third party and customer(s). Customer and third party negotiate for renewable energy service. Regulated utility takes ownership of power through contract with third party. Tariff is set for same price and duration as contract. Contract terminates if customer defaults. Utility remains primary point of contact for billing and (by customer choice) load management/ancillary services. Utility could credit customer bill for project output (at credit amount TBD - e.g. utility's wholesale avoided cost rather than retail rate) and service balance of customer's energy and capacity need (if any) at cost of service rate.

3. Workshop Model 1(c/d) Third Party Owned with Aggregation – Third party owned renewable resource. Regulated utility or third party aggregator could aggregate customers into "VRET load," put that aggregated load out for bid, and contract with third parties to serve that load. And/or regulated utility or third party aggregator could aggregate third party renewable energy generators and

purchase output through fixed price, long term contracts; the regulated utility offers that output to the customers through a "subscription" process. Regulated utility or third party aggregator must match VRET load(s) with aggregated third party renewable energy generators to mitigate issues of timing and risk.

4. Workshop Model 2 Regulated Utility Owned Resource – Regulated utility owns and operates the renewable resource(s) and delivers power to customer. Regulated utility and customer(s) negotiate long-term contract(s) for non-system renewable energy.

5. Workshop Model 2(c/d) Regulated Utility Owned with Aggregation – Regulated utility owns and operates the renewable resource(s), which could be eligible to compete in a Request for Proposal (RFP) for supplying aggregated VRET load (as described in Model 1(c/d)). Regulated utility could aggregate customers into "VRET load," put that aggregated load out for bid, and contract to serve that load. And/or regulated utility could aggregate third party renewable energy generators and purchase output through fixed price, long term contracts; the regulated utility could then offer that output to customers through a "subscription" process.

6. Workshop Model 4(a/x) Customer Owned Resource – Customer owned renewable resource. Regulated Utility role depends on the customer's specific load and resource. Could involve distribution and backup/supplemental services ("firming/shaping"). If customer self-generates renewable energy on site, then likely requires other regulated utility services and may fall under Net Metering. Could be distinct from Net Metering if Regulated Utility credits customer bill for project output (at credit amount TBD – e.g. the utility's wholesale avoided cost rather than retail rate) and serves balance of customer's energy/capacity needs (if any) at cost of service rates. Utility could remain primary point of contact for billing and (by customer choice) load management/ancillary services.

In addition to the VRET models developed through workshops, stakeholders provided models through public comments. These stakeholder VRET models are summarized below. Also, WRI provided a summary table of "Emerging Green Tariffs in U.S. Regulated Electricity Markets" that Staff has included as Appendix 3.[12]

1. NIPPC's Direct Access VRET: A direct access VRET would be separate and distinct from the utilities' current direct access offerings because it would only

[12] The WRI summary table is a helpful illustration of "green tariffs" that are similar to this VRET concept in Oregon, which are being implemented across the country. Staff notes that many of the tariff designs in the WRI summary table could not be adopted in Oregon because of different state laws regarding retail restructuring (among other Oregon-specific laws and policies).

apply for purchase of renewable energy. The necessary regulations are essentially in place, and there is a pre-existing system within direct access to protect non-participating customers, avoid cost shifting, and develop the competitive retail market. In recognition of the benefits of renewable energy, it could be designed to eliminate many of the issues that limit the utility of the "standard" direct access offering, further incenting use of renewable energy. For example, the direct access VRET could have: an on-going open season window, no cap on participation, be available to all industrial and commercial customers regardless of load size, confirmation that new loads would not pay transition charges, customer may take service at some of their meters without taking service at all of their meters, and customer could take service for a portion of their load without being required to take service for all of their load.

2. Renewable Northwest's Direct Project Linkage Pilot Approach: The utility facilitates a financial connection between a particular customer (including one with multiple locations) and a particular renewable energy project or portfolio of projects. The customer's energy charge is replaced with the cost of supply from the renewable energy project, and credit against the demand charge can be given for the renewable resource's capacity contribution. A direct project linkage approach would appeal to customers with strong individual preferences and experience in energy procurement. It may appear somewhat similar to, and thus would need to be explicitly differentiated from or linked to, direct access. This approach may be best suited as a pilot program established by the end of 2015 with a goal of serving at least 150 MW to capture initial demand.

3. Renewable Northwest's Comprehensive Approach: The utility procures via RFP an aggregated portfolio of resources or a single resource for an aggregated pool of participating customers. This approach theoretically could be integrated more comprehensively with utility IRPs and RFPs. VRET renewable resources could essentially influence the environmental quality of resources with which utilities are filling an identified resource need, giving a broader set of customers with less specific supply preferences access to the economies of scale of aggregated procurement, the financial benefits of predictable costs, and a direct influence on a more environmentally responsible utility generating portfolio. This comprehensive approach may be more appropriate after Renewable Northwest's suggested direct project linkage pilot program.

4. PGE's Utility Owned Subscription Model: PGE could aggregate subscribers to pay a premium for a PGE owned green resource. The green resource could be built by a third party through a competitive process. PGE would rate base the equivalent of null power at avoided cost. The PGE system would receive the

power from the green resource and only subscribers would get the RECs to claim the renewable attributes of the green resource. Subscribing customers would take service under PGE's cost of service and the premium paid would secure the RECs from the project for the subscribing customers. This is different than Schedule 54 service as subscribers could identify the resource providing their RECs and without the subscriptions, the green resource would not have been built. All customers would get power produced from the green resource through PGE's system power.

5. PGE's Third Party Owned PPA Model: A customer or third party could own a green resource and the owner would secure transmission to PGE service territory. PGE would purchase the output and RECs on behalf of participating customers. Participating customer(s) would pay PGE's cost of service price and be credited at avoided cost or market for the delivered renewable power. Participating customers could claim both the power and RECs from the resource in proportion to their purchase.

6. Shell's Suggested VRET Model: VRET should be open to all non-residential customers, who should designate a specified percentage (up to 100 percent) of their energy from renewable energy supply offered by third parties. The renewable energy developers and suppliers will negotiate contract terms (price, quantity, term) with participating customers for the "incremental" renewable energy quantity (above the utility's RPS obligation) elected by the customer. Participating suppliers would sell RPS-eligible supplies (matching the supplier's aggregate contracted incremental renewable energy demand) to the utility on a wholesale basis pursuant to a standard contact at a price set by the Commission. The increment or decrement reflecting the difference between the Commission's price and the price agreed upon between the customer and third party supplier would be settled through terms of the contract. Participating customers would pay an "indifference" charge to the utility to account for any incremental costs (firming/shaping, transition adjustment, administrative costs) incurred by the utility to accommodate the integration of new RPS-eligible supplies that exceed the proportion of RPS supplies in the utility's supply portfolio. The purpose of the indifference charge is to ensure non-participating customers are indifferent to the costs of the program. The utility will continue to provide bundled cost-of-service sales service and related services to the participating customers. The utility will maintain the RPS obligation, scheduling, metering, and billing obligation for participating customers. The utility will schedule RPS-eligible supplies delivered to the utility by the third party suppliers.

7. Obsidian Renewables Straw Proposal for Supplemental Green Tariff: During the sufficiency period (7-8 years from project completion) the regulated utility will not be receiving RECs under a PPA with a QF under PURPA. Instead, a supplemental REC purchase agreement could be established where the renewable energy project would sell the RECs to the regulated utility for $X per MWh. The regulated utility could, in turn, offer the RECs to its business customers as a green power supplement to the regular tariff; the business customers are at all times still a regulated utility customer at its meter. The REC price to the customers would be in excess of $X to cover the costs of the program and allow the regulated utility some net benefit.

   - Staff notes that transactions described in the Obsidian Straw Proposal could likely occur through bi-lateral purchase agreements for RECs under existing policies and tariffs (*See* e.g. PGE Schedule 54 and PacifiCorp Schedule 272, which are summarized in Appendix 2).

VI. Analysis VRET Issues in Statutory Factors

Staff used the five statutory factors that are listed in HB 4126 to organize the study on the impact of allowing electric companies to offer VRETs to their non-residential customers. The five statutory factors involve (1) furthering development of significant renewable energy, (2) effect on development of competitive retail markets, (3) impacts on non-participating customers, (4) reliance on competitive procurement, and (5) any other reasonable considerations. These statutory factors also drove the development of the final issues list.

Below, Staff has identified key points of analysis related to each statutory factor and key questions that are likely subjects to consider as conditions in Phase 2. Note that without a specific VRET definition or model to center its analysis, Staff has highlighted key areas of analysis to help further the discussion in Phase 2. Staff acknowledges that all stakeholders' points from public comment are not included below. A summary of stakeholder responses to the final issues list through public comment and reply comments, which is a more complete representation of stakeholders' analysis and issues, is provided in Appendix 5.

The key points of analysis below are general in nature, but Staff intends for this section to be a tool when specific conditions are discussed in Phase 2 or specific tariffs are considered in Phase 3. Key questions to consider are intended to further the discussion in Phase 2 and to help ensure that Phase 2 is not duplicative of Phase 1. The Commission must consider the statutory factors in Phase 2 (potential Commission conditions on future VRET schedules) and Phase 3 (potential Commission approval of

VRET schedules filed by electric companies); therefore, more questions will likely emerge in accordance with specific details of future VRET filings.

(1) Whether allowing electric companies to provide VRETs to non-residential customers promotes the further development of significant renewable energy resources.

This statutory factor requires consideration of promotion of further development of significant renewable energy resources, which involves five key points of analysis: (1) year in which a renewable resource became operational, (2) geographic location of a renewable resource, (3) type of renewable resource, (4) VRET product design, and (5) renewable energy resource baseline and associated amount of additional development above the baseline.

Staff studied the meaning of *significant renewable energy resources* by considering a potential VRET eligible renewable resource's age and geographic location, along with type of renewable resource that could qualify. In addition, Staff considered whether *further development* would involve a VRET that is based on a product for purchase of power and associated bundled RECs versus for purchase of unbundled RECs. Staff also considered the need for a baseline to delineate *further* and to demonstrate additionality of a specific amount of renewable development above the status quo to be *significant*.

A VRET eligible renewable resource that is older in age would not promote further development because the resources already exist but it would likely bring down costs of a VRET program since there are less development costs, which could in turn encourage more customers to sign up. A newer resource would likely increase program costs, but would likely result in more development. A VRET eligible renewable resource that is geographically limited to Oregon or the Pacific Northwest may increase program costs because of this siting constraint, but may have more significance to potential customers that value local generation in Oregon or the region. On the other hand, a VRET eligible renewable resource that is located in the WECC region may bring down costs of the program and encourage more customers to sign up.

There are several considerations in defining the type of renewable resources that are VRET eligible. If VRET eligible resources are defined to be the same as RPS eligible resources, then the VRET may promote development of specific technologies that have been deemed desirable in Oregon. On the other hand, allowing greater flexibility for what constitutes a VRET eligible resource may promote greater overall development of a broader range of resources. Also, there may be options to condition a VRET to use a third party to certify further development of significant renewable energy resources, such as Green-e, which is used in the voluntary renewable energy programs for residential customers. However, non-residential customers may be more sophisticated than residential customers, and may not need comprehensive third party certification of VRET resources in a program.

A VRET may need a baseline to determine what amounts to *further development*. Staff interpreted further development to mean additional development greater than the amount of development expected in the status quo. The renewable energy policy status quo in Oregon includes the utilities' RPS percentage requirements by 2015, 2020, and 2025, renewable QF development, and the utilities' existing voluntary unbundled REC based residential and small commercial voluntary renewable energy portfolio options. The Commission could define a baseline using these categories of renewable resources that are currently required and offered by utilities in Oregon to demonstrate additionality to the status quo. This baseline and associated additionality could also be described as a specific threshold amount of renewable development above the status quo needed to be *significant*. Furthermore, a baseline using the RPS could include the definitional elements of the RPS, such as the meaning of a "bundled" or "unbundled" REC for purposes of a VRET. Creating consistency of terms between renewable energy policies in Oregon would be a helpful first step in determining what is *significant* and how much *further development* amounts to "further development of significant renewable energy resources." On the other hand, choosing a less restrictive baseline, with greater flexibility in products available under a VRET, could encourage more customers to sign up because products under a VRET could be tailored and specifically responsive to their green claim goals and needs.

Further development could also be impacted by whether a VRET would allow product designs that involve unbundled RECs versus bundled RECs from a renewable resource. The questions related to whether unbundled RECs or bundled REC are acceptable to be used in VRET product design would be better informed if the Commission required the same or, at least, similar definitions for unbundled or bundled RECs that are used in the RPS.

For example, a concept regarding an "on-system REC" emerged in considering the Obsidian Renewables Straw Proposal for Supplemental Green Tariff Model (*See* Section V above). This model involved a power purchase agreement between a utility and a QF. During the sufficiency period of approximately seven years, when the QF retains the RECs, the utility and the QF would enter into a supplemental agreement for the utility to buy the RECs from the QF at a premium price. The utility could, in turn, offer these RECs to its non-residential customers as a green power supplement to the regular tariff while they remain utility customers at the meter. In this model, some non-residential customers may value this type of REC as a premium REC because they know it was generated from a renewable resource that is located in the utility's balancing authority, which may therefore be considered a local resource. In the context of the RPS, however, this REC may not be considered a bundled REC, which is why staff and some stakeholders referred to it as an "on-system REC" instead. With RPS definitions at the wholesale level, a REC becomes a "bundled REC" when the REC is acquired by the utility by a trade, purchase, or other transfer of electricity that includes the REC that was issued for that electricity.[13] Adding the next layer of the retail transaction for electricity delivered to the end use non-residential customer, the type of REC the non-residential customer would be receiving is unclear and not fully answered under existing Oregon law and policy.

Finally, there was informal consensus among many stakeholders that a VRET that offered only unbundled RECs (as defined by RPS laws to be without the associated electricity included) could already be offered under existing programs and should not qualify as *further development of significant renewable energy resources.* All three IOUs have tariffs that include riders that would fund the purchase of unbundled RECs (*See* PGE Schedule 54, PacifiCorp Schedule 272, and Idaho Power Schedule 62, which are summarized in Appendix 2).

Key Question for Phase 2 inquiry in VRET conditions:

- What conditions, if any, should be applied to a VRET in order to promote further development of significant renewable energy resources (e.g. resource age limitations, resource geographic limitations, use of RPS for definitions or baseline, etc.)?
- Are there unbundled REC (as defined in Oregon's RPS laws) only products, which do not include the electricity associated with the REC, that would promote further development of significant renewable energy resources?

(2) The effect of allowing electric companies to offer VRETs on the development of a competitive retail market.

HB 4126 Section 3(5) specifically states that rules adopted under ORS 757.646 (1) and 757.659 (7) pursuant to ORS 757.646 (1), which require the Commission to develop policies to eliminate barriers to competitive retail markets, do not bar the Commission from approving a schedule for a VRET that is otherwise consistent with HB 4126 and its

[13] ORS 469A.005 ("Bundled renewable energy certificate means a renewable energy certificate for qualifying electricity that is acquired: (a) By an electric utility or electricity service supplier by ***a trade, purchase or other transfer of electricity*** ***that includes the certificate*** that was issued for the electricity; or (b) By an electric utility by generation of the electricity for which the certificate was issued." (emphasis added)).

findings. The phrase "do not bar" here suggests that the Commission would not completely ignore its charge to develop policies to eliminate barriers to the competitive retail market, but the Commission would take impacts to competitive retail markets into account when determining whether to allow a VRET in Phase 2. In addition, this statutory factor requires consideration of effects on the development of a competitive retail market but permits the Commission to allow electric companies to offer a VRET even if there is an effect on the competitive retail market. In fact, some parties may welcome a VRET that results in a *positive* effect on the competitive retail market. Overall, the Commission will need to balance and reconcile these provisions in considering whether to allow a VRET in Phase 2, and if so, what conditions should apply.

A competitive retail electricity market permits alternative suppliers, other than the regulated utility, to supply electricity to end-use retail customers.[14] A competitive market for non-residential customers has been developed in Oregon since the 1999 passage of SB 1149 with a series of requirements through direct access tariffs offered by PGE and PacifiCorp. An ESS could offer renewable energy through its product offerings under the current structure in Oregon, governed by the existing direct access requirements. Potential effects on the competitive retail market involve two key points of analysis: (1) regulated utility ownership of a VRET resource and (2) whether parity is needed between the requirements of a utility's potential VRET program and the requirements of its direct access program.

If a regulated utility is permitted to own a renewable resource for VRET service energy supply, there may be a negative effect on the development of a competitive retail market. Those customers that may be considering a direct access energy supplier could instead use a VRET to access a similar product without any involvement of an ESS or Independent Power Producer (IPP). This argument is furthered by potential unfairness issues of the regulated utility's monopoly status as compared to an ESS or IPP, such as access to customer information and data, name recognition, and purchasing power. With this argument, not allowing a utility to own a VRET resource may help to ensure that any potential effect in the competitive retail market is more positive rather than

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[14] There does not appear to be a universal definition of a competitive retail electricity market. *See* The Electric Energy Market Competition Task Force, Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy at 84, Note 245 (2006), *available at* http://www.ferc.gov/legal/fed-sta/ene-pol-act/epact-final-rpt.pdf ("The Task Force adopts the convention of designating states as permitting retail competition on the basis of whether a state allows alternative suppliers to enter and obtain multiple, geographically dispersed customers. An even broader potential definition of retail competition would take into account policies that allow individual retail customers to provide some or all of their own generation needs (i.e., to make rather than buy electricity). Onsite generation is common in some industries in some sections of the country. Small onsite generation projects – often referred to as "Distributed Generation" or "Distributed Resources" projects – are gaining popularity as well.")

negative. Positive effects could include more energy supply opportunities that result for an ESS or IPP through a VRET that only allows products that have non-utility owned energy supply.

On the other hand, some may argue that a VRET using a utility owned resource for energy supply would be another option for customers to consider in the competitive retail market. With this argument, if the utility competes in the same competitive market for the acquisition of VRET renewable resources as an ESS or IPP, a VRET using a utility owned resource for energy supply could enhance the competitive market.

The effect of a VRET on the competitive retail market could be evaluated in terms of direct access requirements. From a logical standpoint, it is arguable that there is always some effect unless there is parity between the programs in terms of transition adjustment charges, election windows, and participation caps (among others). Recall that this statutory factor requires consideration of this issue but permits the Commission to allow electric companies to offer a VRET even if there is some effect on the competitive retail market.

The question of whether parity should be required between direct access program requirements and VRET program requirements may turn on whether VRET customers would be "leaving" the cost of service system, similar to direct access customers. If they are "leaving" the system and are on a path to no longer pay for system costs (*See*, e.g., NIPPC Direct Access VRET), then there may not be a rational basis to distinguish the requirements of a VRET and direct access program. In this scenario, effects on the competitive retail market could be ameliorated if the same requirements (transition adjustments, election windows, etc.) were required in both the direct access tariffs and a VRET offered by each utility.

On the other hand, if VRET customers continue to pay for system costs and arguably are not "leaving" the system (*See*, e.g., PGE third party PPA VRET model), then there may not be as strong of a need for parity of requirements between the direct access program and a VRET program because they would be so different in nature. However, competitive retail market entities may still experience a negative effect even if VRET customers continue to pay for system costs (plus a VRET premium) because those VRET customers may have elected direct access but for the utility's VRET product.

<u>Key Questions for Phase 2 inquiry in VRET conditions:</u>

- In order to prevent the potential for negative effects on the competitive retail market, should a VRET condition not allow a regulated utility to own a renewable resource for VRET service energy supply?

- Should a VRET condition require parity between VRET requirements and direct access requirements (e.g. transition adjustment, participation cap, election windows, etc.)?

(3) Any direct or indirect impact, including any potential cost-shifting, on other customers of any electric company offering a VRET.

This statutory factor requires consideration of direct and indirect impacts on non-participating customers. In addition, cost shifting to nonparticipating customers is strictly prohibited in Section 3(4) of HB 4126.[15] Consideration of direct and indirect impacts on nonparticipating customers involves four key points of analysis: (1) VRET service and resource costs, (2) risks related to VRET obligations, (3) stranded costs of the existing cost-of-service rate based system, and (4) RPS resource and compliance costs.

VRET service and resource costs depend on the type of products that are permitted under a VRET. Under a scenario where the regulated utility may own a VRET resource, there would be clear costs for building a VRET resource that would need to be accounted and separated from costs related to the cost-of-service rate based system. Affiliates of regulated utilities are often formed to avoid the need for this type of separate accounting. In fact, the use of affiliates was contemplated in SB 1149 and the direct access regulations.[16] The regulated utilities, in general, have not expressed any interest in forming affiliates. The potential for cost shifting would likely be greatest under a VRET that allows the regulated utility to own separate VRET resources and market those VRET resources to non-residential customers.

Even if the regulated utility does not build and own new VRET resources, there may be costs associated with the utility's promotion of VRET products using existing utility resources and assets, which are paid for by all utility customers. There could be VRET program administration costs, including procurement and power costs of VRET energy supply, billing non-residential customers for purchases from a VRET, educating non-residential customers about the VRET products, and fielding customer calls about VRET products. In addition, there may be costs related to flexible resources needed for integration of incremental VRET renewable energy supply procurement. Integration costs may be applicable in both the scenario where the regulated utility owns a VRET resource and in a scenario where VRET energy is supplied by an ESS or IPP.

[15] HB 4126 (2014), Section 3(4) (stating, in part: ". . . All costs and benefits associated with a voluntary renewable energy tariff shall be borne by the nonresidential customer receiving service under the voluntary renewable energy tariff.").
[16] *See* ORS 757.015 (Affiliated interest defined), *See* also OAR 860-086-0010 (2) ("Affiliate" means a corporation or person who has an affiliated interest, as defined in ORS 757.015, with a public utility).

Indirect impacts to nonparticipating customers include risks related to the VRET and any costs that result from those risks. Depending on the type of transactions in a VRET, there are varying amounts of risk that VRET renewable resources could be under-subscribed if there is not sufficient customer interest or stranded if VRET customers return to the cost-of-service system. If VRET resources are under-subscribed or become stranded, there would be a strict prohibition on assigning those costs to nonparticipating customers. For comparison, in the existing direct access model, these types of risks are borne by the ESS/IPP or the direct access customer. Also in the direct access program, cost-shifting risks are mitigated by capping the MW amount of load permitted to elect service, limiting service to specific sizes of customers, and not permitting meter aggregation to meet size requirements. The same or similar mitigation measures could generally limit the risk of a VRET program.

In a scenario where a product under a VRET amounts to VRET customers "leaving" the cost of service system, there would be stranded costs associated with that departing load (*See*, e.g., NIPPC Direct Access VRET Model). These stranded costs could be remedied in the same way as stranded costs in direct access programs are handled. Direct access customers pay a transition adjustment to prevent cost-shifting, VRET customers could also bear a charge that reflects the above market cost of resources that are stranded as a result of the VRET customer's departure from the cost-of-service rate based system. Arguably, new load would not be leaving stranded costs behind, and should not be subject to transition adjustments. On the other hand, regulated utilities plan for and acquire resources to serve new load in accordance with IRP forecasts.

The cost-of-service rate based system includes costs related to RPS resource procurements and compliance requirements. HB 4126 Section 3(6) specifically states that any electricity procured by an electric company for VRET service may not be used by the utility to comply with its RPS requirements. Depending on the types of transactions permitted under a VRET, there may be questions about whether utility RPS target calculations that are based on the "total retail sales" of the utility should include VRET load and VRET sales.

RPS targets are calculated as a percentage of the total retail sales of each utility. As a VRET looks more and more like direct access, with customers "leaving" the cost-of-service rate-based system, those VRET customers may not be part of the utility's total retail sales like direct access customers are not part of the utility's total retail sales. In this scenario, the VRET customer is likely receiving its electricity from a third party while the utility is providing the framework or structure under which to make those purchases. However, as the amount of the utility's total retail sales decrease, so does the utility's

RPS target since the target is a function of the total retail sales. This could lead to an overall weakening of the utility's RPS targets and an indirect impact to non VRET customers.

Customers could seek to be partial VRET customers, where part of their load is served through the VRET and part of their load is served through the cost-of-service rate-based system. Those partial VRET customers would continue to pay for the utility's RPS compliance costs, which would be detailed in their tariff, in order to avoid impacts to non VRET customers. However, their RPS related claims would be proportional to the percentage of their load that is served by the cost-of-service rate-based system.

Under ORS 469A.052, RPS compliance requirements are calculated as a function of the utility's retail load, meaning no resources are exempt from inclusion in the RPS compliance obligation. Depending on how VRET resources are characterized, VRET customers could be part of the utility's total retail load and potentially increase the resulting RPS target. On the other hand, VRET resources could be characterized more like third party resources in direct access. In that scenario, RPS compliance requirements could follow the methodology used by ESSs. Because VRET customers may need RECs from VRET resources for their green power claims and RECs from VRET resources are prohibited from being used to comply with the RPS (HB 4126 Section 3(6)), RPS compliance requirements from VRET load could be fulfilled through unbundled RECs. This is similar to how ESSs comply with their RPS targets based on the service territory that their customer load is located.

Key Questions for Phase 2 inquiry in VRET conditions:

- In order to prevent the potential for cost shifting to nonparticipating customers, should a VRET condition not allow a regulated utility to own a renewable resource for VRET service energy supply?
- Should a VRET condition require identification of all potential costs, risks, and mitigation measures and require demonstration that all direct and indirect impacts to nonparticipating customers are prevented?

(4) Whether the VRETs provided by electric companies to non-residential customers rely on electricity supplied through a competitive procurement process.

This statutory factor requires consideration of a competitive procurement process for VRET energy supply. The use of a competitive procurement process as part of a VRET involves two key points of analysis: (1) the type of VRET framework and (2) regulated utility ownership of a VRET resource.

A competitive procurement process may be relevant to only certain types of VRETs. If a product permitted under a VRET involves the regulated utility aggregating renewable resources for customer subscription, then a competitive procurement process may help ensure the lowest cost resource procurement.

On the other hand, products permitted under a VRET that involve a third party owned resource, which are directly supplied to customers through a utility facilitated transaction (similar to a power purchase agreement), may not need to use a competitive procurement process. Potential VRET customers and ESSs or IPPs would likely negotiate costs and attributes of renewable resources. These non-residential customers, which typically have large loads, may have preferences, expertise, or market connections that could ensure competitively priced VRET resources. Requiring the use of a competitive procurement process when it may not be needed to yield the lowest cost procurement could add unnecessary administrative costs that raise prices for potential VRET customers.

In a scenario where the regulated utility is engaged in providing VRET resource supply (*See*, e.g. PGE's Utility Owned Subscription Model), a competitive process may be needed to help ensure the lowest cost procurement of VRET resources. In particular, if the regulated utility is permitted to include a self-build option, a competitive process may be necessary. The rationale for requiring a competitive process in this scenario is similar to the rationale for using the competitive bidding guidelines for major resource procurement, which are resource acquisitions with duration greater than five years and quantities greater than 100 MW.

Key Questions for Phase 2 inquiry in VRET conditions:

- Should a VRET condition require the use of a competitive procurement process if certain triggers are present (e.g. utility ownership of a VRET resource or aggregation of resources for subscription), and, if so, what triggers would require the need for a competitive procurement process?

(5) Any other reasonable consideration related to allowing electric companies to offer VRETs to their non-residential customers.

Many stakeholders highlighted several other potential VRET considerations in their comments. Staff agrees issues related to consumer protection should be further considered. There are two key points of analysis in the consumer protection context: (1) need for third party certification and (2) power mix disclosures.

A VRET could require products to have third party verification or oversight that ensures that the products conform to customer "green claim" expectations and renewable energy and environmental attribute markets. Certification would encourage the VRET program to meet national standards and evolve over time. EPA's green power partnership encourages the purchase of products that are certified by an independent third party.[17] For example, Green-e certification is used for the residential voluntary renewable energy program in Oregon. Green-e certified retail sales of 33.5 million MWh in 2013. Non-residential buyers accounted for the majority of certified MWh purchased, at over 30 million MWh.

On the other hand, customers electing to use a product under a VRET offering are likely informed and sophisticated non-residential customers. These types of customers may not need the same consumer protections, such as Green-e certification and POC oversight, provided for residential customers. In this scenario, PUC oversight with stakeholder involvement would remain and serve as some protection for consumers. In addition, if RPS eligible resource criteria and RPS definitions related to renewable resources are also used for the VRET to fulfill the first statutory factor of furthering significant new renewable energy development, ODOE could certify those resources as it does for RPS compliance.

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[17] *See* EPA's Green Power Partnership – Partnership Requirements (January 2013), available at http://www.epa.gov/greenpower/documents/gpp_partnership_reqs.pdf

Resources developed for a VRET, for which customers claim environmental attributes, should be fairly characterized in utility power mix disclosures. It is arguable that if environmental attributes associated with VRET renewable energy procurement are conveyed to customers, then those attributes are not part of the utility's cost-of-service rate based system, cannot be claimed by utility, and should not be reflected in the utility's power mix disclosures.

Depending on the type of VRET adopted, the resource mix associated with the VRET could be included as a label pursuant to OAR 860-038-0300 (Electric Company and Electricity Service Suppliers Labeling Requirements). If specialized products under a VRET are negotiated for individual customers (*See*, e.g. NIPPC's Direct Access VRET Model), then customers may need to be provided with specialized labels so that VRET customers clearly understand the resources they are receiving compared to the utility's cost-of-service rate-based power mix. There may be more specific disclosure questions that arise if products under a VRET permit customers to maintain a connection to the cost-of-service rate-based system (*See*, e.g., PGE Third Party PPA Model) or partial VRET customers are permitted. There may be questions about how customers claim utility supplied RPS renewable energy and incremental VRET renewable energy supply as part of the customer's overall renewable energy supply in comparison to how the utilities reflect these resources in their utility power mix disclosures.

<u>Key Questions for Phase 2 inquiry in VRET conditions</u>:

- Should a VRET condition require the use of third party renewable energy verification?

VII. Analysis of Threshold Question: Whether to allow a VRET in Phase 2?

The statute requires the Commission to decide the answer to the threshold question: whether, and under what conditions, it is reasonable and in the public interest to allow electric companies to provide voluntary renewable energy tariffs to non-residential customers. Given the public policy issues in each statutory factor discussed above that should be resolved through VRET conditions, the Commission must decide whether it is reasonable and in the public interest to allow utilities to offer a VRET at all. As used in Section 3(2) of HB 4126, Staff's counsel advises that the meaning of the phrase "is reasonable and in the public interest" is informed by the five statutory factors set forth in Section 3(2)(a)-(e).[18]

[18] Generally, Commission orders interpreting the meaning of "in the public interest" are specific to the statute at issue in that proceeding. For example, in the context of utility mergers, "public interest" under ORS 759.375 means there is "no harm" to the public if the merger is allowed. *See* Order No. 09-169. But, in the context of an entity acquiring a utility, "public interest" under ORS 757.511 means there must be

Even though there are two subparts of the threshold question, in essence, there is one question asking whether the public interest benefits of offering a VRET outweighs the costs of implementing necessary conditions to that VRET. In Phase 2, the Commission will need to weigh these five statutory factors and conclude whether it is reasonable and in the public interest to allow VRETs to be offered by utilities to non-residential customers. In Staff's view, the Commission's public interest inquiry should include the following considerations:

1. Whether it is reasonable and in the public interest to allow utilities to provide non-residential customers with an additional renewable energy product choice because those non-residential customers do not have sufficient options for renewable energy products through existing policies?
2. Whether it is reasonable and in the public interest for regulated utilities to be able to offer a new renewable energy product choice that is valuable to customers because there are benefits in the regulated utility making such an offering?
3. Whether it is reasonable and in the public interest to create a special VRET program, requiring administrative burden on staff and parties through regulated proceedings, to allow utilities to offer a product that they may already be able to offer by forming an affiliate through direct access?

VIII. <u>Results to Consider in Phase 2</u>

HB 4126 directs the Commission to consider the results of the study in Phase 2. Staff considered a great deal of input and materials, as evidenced by this study and its appendices, and makes the following findings (in addition to the key questions for Phase 2 described above):

1. There is not a clear, agreed upon definition of a VRET, nor does HB 4126 provide a definition or list of attributes of a VRET in Oregon. Staff understands that many stakeholders describe a VRET as a utility offering that allows non-residential customers to voluntarily elect to pay a higher rate than their typical customer tariff because they are seeking renewable energy supply, an ability to make a "green power claim," and/or long-term and less-volatile energy costs. This description permitted a wide range of VRET models offered by stakeholders with differing design features involving system ownership, types of eligible renewable energy resources, load aggregation, utility role in connecting to third

"net benefits" to the public if the acquisition is allowed. *See* Order No. 06-082. In the context of ORS 757.415(2)(b) (purposes for which securities and notes may be issued), the Oregon DOJ has opined that "compatible with the public interest" is explained by the context of the other language/factors/criteria set forth in that particular statutory section.

party renewable energy suppliers, and use of Q Fs under PURPA (among others). This wide range of VRET models led to different impacts when the statutory factors were considered, which raised different policy issues and potential conditions.

2. Considering a wide range VRET models was a helpful exercise to discover potential issues that may or may not be resolved through conditions. However, it is not necessary to develop a hypothetical, detailed VRET model in order to determine appropriate and reasonable conditions in Phase 2. In addition, it is difficult for staff and stakeholders to answer the threshold question of whether to allow VRETs without also considering the potential conditions that would constrain subsequent, more detailed VRET filings in Phase 3. This circular analysis suggests that the threshold question of whether to allow VRETs and potential conditions on VRETs should be answered together to best inform stakeholders, the Commission, and Staff.

3. The key questions for Phase 2, described above, that Staff determined through its analysis of the threshold question and statutory factors should be, at a minimum, the focus of Phase 2, which will help to focus parties' responses on the threshold question and potential conditions. Analysis of the five statutory factors revealed to Staff that there are significant issues and considerations that could constrain a VRET, including, but not limited to:

    - *Furthering Development of Significant Renewable Energy Resources*: Tailored REC based products are already available under existing utility tariffs and may fulfill the needs of some non-residential customers interested in making a green power claim through a utility green energy product, but a tailored REC based product may not be sufficient to be a VRET.
    - *Preventing Cost Shift to Non-Participating Customers*: VRETs must prevent cost shifting (strictly prohibited in HB 4126), which implies the need for the accounting of utility system costs similar to transition adjustments in direct access programs and limits the utilities' options in designing a VRET that is attractive to those non-residential customers seeking a low cost green power product.
    - *Effect on Competitive Retail Market*: While HB 4126 allows that the Commission's policies to eliminate barriers to competitive retail markets does not bar approval of a VRET, negative impacts to the competitive marketplace and fairness concerns may require a level playing field between a VRET and direct access programs.

77th OREGON LEGISLATIVE ASSEMBLY--2014 Regular Session

Enrolled
House Bill 4126

Sponsored by Representative SMITH; Representative LININGER (Presession filed.)

CHAPTER ....

AN ACT

Relating to utilities.

Be It Enacted by the People of the State of Oregon:

SECTION 1. Section 2 of this 2014 Act is added to and made a part of ORS 469A.005 to 469A.210.

SECTION 2. Unless the exemption provided by ORS 469A.055 (1) terminated for the consumer-owned utility pursuant to ORS 469A.055 (5), a consumer-owned utility described in ORS 469A.052 (2) that is subject to the large utility renewable portfolio standard described in ORS 469A.052 (3) may use, notwithstanding ORS 469A.145 (1), unbundled renewable energy certificates, including banked unbundled renewable energy certificates, to meet:

(1) Up to 100 percent of the standard described in ORS 469A.052 (3)(a); and

(2) Up to 75 percent of the standard described in ORS 469A.052 (3)(b) or (c).

SECTION 3. (1) As used in this section, "electric company" has the meaning given that term in ORS 757.600.

(2) The Public Utility Commission shall conduct a study to consider the impact of allowing electric companies to offer voluntary renewable energy tariffs to their nonresidential customers. The study shall be subject to public comment in a manner determined by the commission.

(3) The commission shall consider the results of the study described in subsection (2) of this section in conjunction with the factors specified in this subsection to determine whether, and under what conditions, it is reasonable and in the public interest to allow electric companies to provide voluntary renewable energy tariffs to nonresidential customers. The factors the commission shall consider are:

(a) Whether allowing electric companies to provide voluntary renewable energy tariffs to nonresidential customers promotes the further development of significant renewable energy resources;

(b) The effect of allowing electric companies to offer voluntary renewable energy tariffs on the development of a competitive retail market;

(c) Any direct or indirect impact, including any potential cost-shifting, on other customers of any electric company offering a voluntary renewable energy tariff;

(d) Whether the voluntary renewable energy tariffs provided by electric companies to nonresidential customers rely on electricity supplied through a competitive procurement process; and

(e) Any other reasonable consideration related to allowing electric companies to offer voluntary renewable energy tariffs to their nonresidential customers.

(4) If the commission determines under subsection (3) of this section to allow electric companies to offer voluntary renewable energy tariffs to nonresidential customers, the commission may authorize an electric company to file a schedule with the commission that establishes the rates, terms and conditions of services offered under the voluntary renewable energy tariff. All costs and benefits associated with a voluntary renewable energy tariff shall be borne by the nonresidential customer receiving service under the voluntary renewable energy tariff. Schedules shall be submitted and considered in accordance with ORS 757.205, 757.210, 757.212 and 757.215. The commission also shall consider the factors specified in subsection (3) of this section when determining whether to approve a schedule.

(5) ORS 757.646 (1) and rules adopted under ORS 757.646 (1) and 757.659 (7) pursuant to ORS 757.646 (1) do not bar the commission from approving a schedule for a voluntary renewable energy tariff that is consistent with this section and commission findings.

(6) Any qualifying electricity, as defined in ORS 469A.005, procured by an electric company to provide electricity pursuant to a voluntary renewable energy tariff described in this section may not be used by the electric company to comply with the requirements of the renewable portfolio standard described under ORS 469A.052 or 469A.055.

Passed by House February 11, 2014

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Ramona J. Line, Chief Clerk of House

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Tina Kotek, Speaker of House

Passed by Senate February 28, 2014

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Peter Courtney, President of Senate

Received by Governor:

........................M.,.., 2014

Approved:

........................M.,.., 2014

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John Kitzhaber, Governor

Filed in Office of Secretary of State:

........................M.,.., 2014

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Kate Brown, Secretary of State

Appendix 2

Existing IOU Tariffs Relevant to VRET discussion

Net Energy Metering - For customers intending to operate net metering systems to generate electricity to reduce all or part of their monthly energy usage.

- *PGE Schedule 203 (Net Metering Service)* – For a customer with installed generating equipment that qualifies as a Net Metering Facility defined in ORS 757.300(1)(d). Such customer is referred to as a customer-generator and defined in OAR 860-039-0005(2)(e). Service under this schedule is provided pursuant to the requirements of OAR 860-039-0005 through -0080 and ORS 757.300. Net metering measures the difference between the electricity supplied by PGE and the electricity generated by a customer-generator that is fed back to the Company over an applicable Billing Period. Net metered generation is supplied to PGE from a customer that operates an interconnected power production facility using solar power, wind power, fuel cells, hydroelectric power, landfill gas, digester gas, waste, dedicated energy crops available on a renewable basis or low-emission, nontoxic biomass based on solid organic fuels from wood, forest or field residues where the generating nameplate capacity is 2 MW or less for non-residential customers and 25 kW or less for residential customers. The facility must operate in parallel with PGE's existing facilities and be primarily intended to offset part or all of the customer's own electrical requirements.

- *PacifiCorp Schedule 135 (Net Metering Service Optional for Qualifying Customers)* – For any customer that uses a generating facility using solar power, wind power, fuel cells, hydroelectric power, landfill gas, digester gas, waste, dedicated energy crops available on a renewable basis or low-emission, nontoxic biomass based on solid organic fuels from wood, forest or field residues with a capacity of not more than twenty-five (25) kilowatts for residential customers and two (2) megawatts for non-residential customers that is located on the customers' premises, is interconnected and operates in parallel with PacifiCorp's existing transmission and distribution facilities, and is intended primarily to offset part or all of the customer's own electrical requirements. This Schedule is offered in compliance with ORS 757.300 and OAR 860-039-0005 through -0080.

- *Idaho Power Company Schedule 84 (Customer Energy Product Net Metering Service)* – Service under this schedule is applicable to any Customer that: Does not take service under Schedule 4 or Schedule 5; Owns and/or operates a Generation Facility fueled by solar, wind, biomass, geothermal, or hydropower, or represents fuel cell technology; Maintains its retail electric service account for the loads served at the Point of Delivery adjacent to the Generation Interconnection Point as active and in good standing; Meets all requirements applicable to Net Metering Systems detailed in the Company's Schedule 72 Interconnections to Non-Utility Generation; and takes retail service under Schedules 1 or 7 with total nameplate capacity rating of 25 kW or smaller or takes retail service on another Schedule but with a total nameplate capacity rating of 100 kW or smaller.

Appendix 2

Voluntary REC based Tariffs – REC based products available to nonresidential customers paid for through a rider.

- *PGE Schedule 54 (Large Nonresidential Tradable Renewable Credits Rider)* – This rider is an optional supplemental service that supports the development of New Renewable Energy Resources as defined in ORS 757.600. Under this Schedule a large nonresidential customer may purchase Tradable Renewable Credits (RECs) based on a percentage of the customer's load, subject to a minimum purchase. The purchase guarantees an equivalent amount of generation from qualified renewable resources will be transmitted within the Western Electricity Coordinating Council.

- *PacifiCorp Schedule 272 (Renewable Energy Rider Optional Bulk Purchase Option)* – For large nonresidential customers receiving delivery service. Funds received from consumers under this Schedule will cover program costs and match renewable energy purchases to block purchases. 1 Block equals 100 kWh of Renewable Energy. This program requires a minimum purchase of 121.2 megawatt-hours (121,200 kWh or 1,212 Blocks) per year. $0.70 per month ($7.00 per MWh per month) Plus $1500.00 per year fixed charge. Funds not spent after covering program costs and matching renewable energy purchases to block purchases may be used to fund qualifying initiatives, such as locally-owned commercial-scale renewable energy projects, research and development projects encouraging renewable energy market transformation, and investment in above-market costs of constructing renewable energy facilities. For purchase commitments over two years in length or large purchases over 75,000 MWh per year, individually negotiated arrangements may be available, pursuant to the execution of a written contract.

- *Idaho Power Schedule 62 (Green Energy Purchase Program Rider (Optional))* – Optional voluntary programs designed to provide customers an opportunity to participate in the purchase of new environmentally friendly "green" energy. Funds collected in this program are wholly distributed to the purchase of green energy products.

PURPA Qualifying Facilities (QF) – Qualifying cogeneration facilities or qualifying small power production facilities within the meaning of section 201 and 210 of the Federal Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. 796 and 824a-3. Electricity from a renewable QF must meet the requirements of "qualifying electricity" set forth in the Oregon Renewable Portfolio Standards: ORS 469A.010, 469A.020, and 469A.025.

- *PGE Schedule 201 (Qualifying Facility 10 MW or less Avoided Cost Power Purchase Information)* – For power purchased from small power production or cogeneration facilities (10 MW or less) that are QFs as defined in 18 CFR Section 292, that meet the eligibility requirements described in the schedule and where the energy is delivered to PGE's system and made available for PGE purchase pursuant to a Standard PPA.

Appendix 2

- *PacifiCorp Schedule 37 (Avoided Cost Purchases from Qualifying Facilities of 10,000kw or less)* - For power purchased from Qualifying Facilities with a nameplate capacity of 10,000 kW or less or that, together with any other electric generating facility using the same motive force, owned or controlled by the same person(s) or affiliated person(s), and located at the same site, has a nameplate capacity of 10,000 kW or less. Owners of these Qualifying Facilities will be required to enter into a written power sales contract with the Company.

- *PacifiCorp Schedule 38 (Avoided Cost Purchases from Qualifying Facilities of Greater than 10,000kw)* – For power purchased from Qualifying Facilities with a nameplate capacity greater than 10,000 kW. Owners of these Qualifying Facilities will be required to enter into a negotiated written power purchase agreement with the Company. Pursuant to Order No. 05-584 and 07-360, the pricing options specified in Schedule 37 should serve as a starting point for prices under a negotiated power purchase agreement.

- *Idaho Power Schedule 85 (Cogeneration and Small Power Production Standard Contract Rates)* – Service under this schedule is applicable to any seller that: Owns or operates a Qualifying Facility with a nameplate capacity rating of 10 MW or less and desires to sell energy generated by the Qualifying Facility to the Idaho Power in compliance with all the terms and conditions of the Standard Contract; and Meets all applicable requirements of Idaho Power's Generation Interconnection Process. For Qualifying Facilities with a nameplate capacity rating greater than 10 MW, a negotiated Non-Standard Contract between the seller and Idaho Power is required.

Partial Requirements Tariffs – PGE and PacifiCorp have Partial Requirements Tariffs that allow a customer to supply all or some portion of their own load by self-generation on a regular basis, depending on size.

- PGE's Partial Requirement Tariffs

    - *PGE Schedule 75 (Partial Requirements Service)* – To Large Nonresidential Customers supplying all or some portion of their load by self-generation operating on a regular basis, where the self-generation has a total nameplate rating of 2 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

    - *PGE Schedule 76R (Partial Requirements Economic Replacement Power Rider)* – Provides customers served on Schedule 75 with the option of purchasing energy from PGE to replace some, or all, of the customer's on-site generation when the customer deems it is more economically beneficial than self-generating.

- *PGE Schedule 575 (Partial Requirements Service Direct Access Service)* – For large nonresidential customers who receive electricity service from an ESS and who supply all or some portion of their load by self-generation operating on a regular basis, where the self-generation has a total nameplate rating of 2 MW or greater. A large nonresidential customer is a customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

- *PGE Schedule 576R (Economic Replacement Power Rider Direct Access Service)* – To provide Customers served on Schedule 575 with the option for delivery of Energy from the Customer's Electricity Service Supplier (ESS) to replace some, or all of the Customer's on-site generation when the Customer deems it is more economically beneficial than self-generating.

- <u>PacifiCorp Partial Requirement Tariffs</u>

  - *PacifiCorp Schedule 47 (Large General Service Partial Requirements 1 000 KW and Over Delivery Service)* – For large nonresidential consumers supplying all or some portion of their load by self-generation operating on a regular basis, requiring standby electric service from PacifiCorp where the consumer's self-generation has both a total nameplate rating of 1,000 kW or greater and where standby electric service is required for 1,000 kW or greater. Consumers requiring standby electric service from PacifiCorp for less than 1,000 kW shall be served under the applicable general service schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 747, Direct Access Delivery Service.

  - *PacifiCorp Schedule 247 (Partial Requirements Supply Service)* – For large nonresidential consumers receiving Delivery Service under Schedule 47. Details how the energy charge is calculated (baseline energy, scheduled maintenance energy, unscheduled energy), as well as losses and special conditions.

  - *PacifiCorp Schedule 747 (Large General Service Partial Requirements 1 000 KW and Over Direct Access Delivery Service)* – This Schedule is applicable to consumers who have chosen to receive electricity from an ESS. For large nonresidential consumers supplying all or some portion of their load by self-generation operating on a regular basis, requiring standby electric service from the Company where the consumer's self-generation has both a total nameplate rating of 1,000 kW or greater and where standby electric service is required for 1,000 kW or greater. Consumers requiring standby electric service from the Company for less than 1,000 kW shall be served under the applicable general service schedule.

Appendix 2

Direct Access Tariffs

- PGE Cost-of-Service Opt-Out Tariffs

  - *PGE Schedule 485 (Transmission access service – Large Nonresidential (201 - 4,000 kW) Cost of Service Opt-out)* – For large nonresidential customers whose demand has exceeded 200 kW more than six times in the preceding 13 months but has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a demand exceeding 4,000 kW and who has chosen the PGE's transition plan during one of the enrollment periods. Service under this schedule is limited to the first 300 MWa. Beginning with the September 2004 Enrollment Period C, customers have a minimum five-year option and a fixed three-year option.

  - *PGE Schedule 489 (Transmission access service - Large Nonresidential (>4,000 kW) Cost of Service Opt-out)* – For large nonresidential customers whose demand has exceeded 4,000 kW more than once within the preceding 13 months and who has chosen PGE's transition plan during an enrollment period. Service under this schedule is limited to the first 300 MWa. Beginning with the September 2004 Enrollment Period C, customers have a minimum five-year option and a fixed three-year option.

  - *PGE Schedule 490 (Transmission access service – Large Nonresidential Cost-of-Service Opt-Out (>4,000 kW and Aggregate to >100 MWa))* – For large nonresidential customers who meet the following conditions: 1) individual account demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a demand exceeding 4,000 kW; and 2) where combined usage of all accounts meeting condition 1 for the large nonresidential customer aggregate to at least 100MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account; and 4) who has chosen PGE's transition plan during an enrollment period. Service under this schedule is limited to the first 300 MWa. Customers have a minimum five-year option and a fixed three-year option.

  - *PGE Schedule 491 (Transmission access service – Street and Highway Lighting Cost of Service Opt-Out)* – For municipalities or agencies of federal or state governments with no fewer than 30,000 lights purchasing Direct Access for lighting service utilizing PGE approved street lighting equipment for public streets and highways and public grounds where funds for payment of electricity are provided through taxation or property assessment. Service under this schedule is limited to the first 300 MWa.

  - *PGE Schedule 492 (Transmission access service – Traffic Signals Cost of Service Opt-Out)* – To municipalities or agencies of federal or state governments served on Schedule 92, who purchase Electricity from an

Electricity Service Supplier (ESS) for traffic signals and warning facilities in systems containing at least 500 intersections on public streets and highways, where funds for payment of Electricity are provided through taxation or property assessment. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001. Service under this schedule is limited to the first 300 MWa

- *PGE Schedule 495 (Transmission access service - Street and highway lighting new technology Cost of Service Opt-Out)* - For municipalities or agencies of federal or state governments with no fewer than 30,000 lights purchasing Direct Access for lighting service utilizing Company approved streetlighting equipment for public streets and highways and public grounds where funds for payment of Electricity are provided through taxation or property assessment. Service under this schedule is limited to the first 300 MWa.

- <u>PGE Direct Access Tariffs</u>

  - *PGE Schedule 515 (Direct access - outdoor area lighting)* – Lighting services, which consist of the provision of PGE-owned luminaires mounted on PGE-owned poles, in accordance with PGE specifications as to equipment, installation, maintenance and operation.

  - *PGE Schedule 532 (Direct access - small nonresidential)* - Sixty-hertz alternating current of such phase and voltage as PGE may have available.

  - *PGE Schedule 538 (Direct access - large nonresidential optional time of day)* – Large nonresidential customers who have chosen to receive service from an ESS, and: 1) served at secondary voltage with a monthly demand that does not exceed 200 kW more than once in the preceding 13 months; or 2) who were receiving service on Schedule 38 (large Nonresidential Optional Time-of-Day Standard Service (Cost of Service)) as of December 31, 2015.

  - *PGE Schedule 549 (Direct access - large nonresidential irrigation and drainage pumping)* - Large nonresidential customers who have chosen to receive electricity from an ESS for irrigation and drainage pumping; may include other incidental service if an additional meter would otherwise be required.

  - *PGE Schedule 583 (Direct access - large nonresidential (31-200 kW))* - Large nonresidential customers whose demand has not exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a demand exceeding 4,000 kW and who has chosen to receive electricity from an ESS.

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- *PGE Schedule 585 (Direct access - large nonresidential (201-4000kW))* - Large nonresidential customers whose demand has exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a demand exceeding 4,000 kW and who has chosen to receive electricity from an ESS.

- *PGE Schedule 589 (Direct access - large nonresidential (greater than 4000kW)* - Large nonresidential customer whose demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a demand exceeding 4,000 kW, and who has chosen to receive electricity from an ESS.

- *PGE Schedule 590 (Direct access - large nonresidential (greater than 4000 kW and aggregate to greater than 100 MWa))* - Large nonresidential customer who meet the following conditions: 1) individual account demand has exceeded 4,000 kW at least twice within the preceding 13 months, or with seven months or less of service has had a demand exceeding 4,000 kW; and 2) where combined usage of all accounts meeting condition 1 for the large nonresidential customer aggregate to at least 100 MWa in a calendar year; and 3) the customer maintains a load factor of 80% or greater for each account; and 4) who has chosen to receive electricity from an ESS.

- *PGE Schedule 591 (Direct access - street and highway lighting)* - municipalities or agencies of federal or state governments purchasing Direct Access for lighting service utilizing PGE approved street lighting equipment for public streets and highways and public grounds where funds for payment of electricity are provided through taxation or property assessment.

- *PGE Schedule 592 (Direct access - traffic signals)* - municipalities or agencies of federal or state governments served on Schedule 92, who purchase Electricity from an Electricity Service Supplier (ESS) for traffic signals and warning facilities in systems containing at least 50 intersections on public streets and highways, where funds for payment of Electricity are provided through taxation or property assessment. This schedule is available only to those governmental agencies receiving service under Schedule 92 as of September 30, 2001.

- *PGE Schedule 595 (Direct access - street and highway lighting new technology)* - municipalities or agencies of federal or state governments purchasing Direct Access for lighting service utilizing Company approved street lighting equipment for public streets and highways and public grounds where funds for payment of Electricity are provided through taxation or property assessment.

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- <u>PacifiCorp's Direct Access Tariffs</u>

  - *PacifiCorp Schedule 723 (General Service Small Nonresidential Direct Access Delivery Service)* – for small nonresidential consumers who have chosen to receive electricity from an ESS, and as specified in the PacifiCorp's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed, except for Communication Devices. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

  - *PacifiCorp Schedule 728 (General Service Large Nonresidential 31 KW to 200 KW Direct Access Delivery Service)* – for large nonresidential consumers who have chosen to receive electricity from an ESS, and whose loads have not registered more than 200 kW, more than six times in the preceding 12-month period and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

  - *PacifiCorp Schedule 730 (General Service Large Nonresidential 201 KW to 999 KW Direct Access Delivery Service)* – for large nonresidential consumers who have chosen to receive electricity from an ESS, and whose loads have registered more than 200 kW, more than six times in the preceding 12-month period but have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedule 747 or 748. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one year period will be provided only by special contract for such service.

  - *PacifiCorp Schedule 741 (Agricultural Pumping Service Direct Access Delivery Service)* – For consumers who have chosen to receive electricity from an ESS and desiring service for agricultural irrigation or agricultural soil drainage pumping installations only and whose loads have not registered 1,000 kW or more, more than once in the preceding 18-month period and who are not otherwise subject to service on Schedule 747 or 748. Service furnished under this Schedule will be metered and billed separately at each point of delivery.

  - *PacifiCorp Schedule 747 (Large General Service Partial Requirements 1 000 KW and Over Direct Access Delivery Service)* – For consumers who have chosen to receive electricity from an ESS. For large nonresidential consumers supplying all or some portion of their load by self-generation operating on a regular basis, requiring standby electric service from the PacifiCorp where the consumer's self-generation has both a total nameplate rating of 1,000 kW or greater and where standby electric service is required for 1,000 kW or greater. Consumers requiring standby electric service from the Company for less than 1,000 kW shall be served under the applicable general service schedule.

- *PacifiCorp Schedule 776R (Large General Service Partial Requirements Service Economic Replacement Service Rider Direct Access Delivery Service)* – For consumers served on Schedule 747 with the opportunity of purchasing Energy from an ESS to replace some or all of the consumer's on-site generation when the consumer deems it is more economically beneficial than self-generating.

- *PacifiCorp Schedule 748 (Large General Service 1 000 KW and Over Direct Access Delivery Service)* – For consumers who have chosen to receive electricity from an ESS, to electric service loads which have registered 1,000 kW or more, more than once in a preceding 18-month period. This Schedule will remain applicable until Consumer fails to exceed 1,000 kW for a subsequent period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service. Partial requirements service for loads of 1,000 kW and over will be provided only by application of the provisions of Schedule 747.

- *PacifiCorp Schedule 751 (Street Lighting Service Company Owned System Direct Access Delivery Service)* – For consumers who have chosen to receive electricity from an ESS. To unmetered lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of PacifiCorp owned, operated and maintained street lighting systems controlled by a photoelectric control or time switch.

- *PacifiCorp Schedule 752 (Street Lighting Service Company Owned System No New Service Direct Access Delivery Service)* – For consumers who have chosen to receive electricity from an ESS. To service furnished by means of PacifiCorp-owned installations, for the lighting of public streets, highways, alleys and parks under conditions and for street lights of sizes and types not specified on other schedules of this Tariff. PacifiCorp may not be required to furnish service hereunder to other than municipal Consumers. This schedule is closed to new service beginning November 8, 2006.

- *PacifiCorp Schedule 753 (Street Lighting Service Consumer Owned System Direct Access Delivery Service)* – For consumers who have chosen to receive electricity from an ESS. For lighting service provided to municipalities or agencies of municipal, county, state or federal governments for dusk to dawn illumination of public streets, highways and thoroughfares by means of consumer owned street lighting systems controlled by a photoelectric control or time switch.

- *PacifiCorp Schedule 754 (Recreational Field Lighting Restricted Direct Access Delivery Service)* – For consumers who have chosen to receive electricity from an ESS. For schools, governmental agencies and nonprofit organizations for service supplied through one meter at one point of delivery and used exclusively for annually recurring seasonal lighting of outdoor athletic or recreational fields. This Schedule is not applicable to any enterprise that is operated for profit. Service for purposes other than recreational field lighting may not be combined with such field lighting for billing purposes under this Schedule. At consumer's option, service for recreational field lighting may be taken under PacifiCorp's applicable General Service Schedule.

- <u>PGE ESS Charge</u>: *Schedule 600 (Electricity Service Supplier Charges)* – applicable to any ESS providing service to PGE customers. To receive service, an ESS must sign an ESS Service Agreement and abide by tariff provisions. Charges includes application processing fee, registration renewal fee, electronic data interchange testing, charge of effective date request, switching fee, customer change of location, consolidating billing, late pay charge, and historical customer usage download and data charge.

- <u>PacifiCorp ESS Charge:</u> *PacifiCorp Schedule 600 (ESS Charges)* - For ESSs providing or seeking to provide service to Consumers in the territory served by PacifiCorp in Oregon. Includes an ESS Service Agreement charge, pre-enrollment usage information, pre-enrollment payment history, DASR processing fee, late payment charge, consolidated billing charges, ESS security deposit interest rate, and cost based prices for any other work at ESS request.

- <u>PGE Transition Adjustments Tariffs</u>

  - *PGE Schedule 128 (Short-term transition adjustment)* – this schedule calculates the Short-Term Transition Adjustment to reflect the results of the ongoing valuation under OAR 860-038-0140. It is applicable to all nonresidential customers who receive Direct Access service on Schedules 515, 532, 538, 549, 575, 583, 585, 589, 590, 591, 592 and 595 (among others).

- *PGE Schedule 129 (Long-term transition adjustment)* – applicable to large nonresidential customers that have selected service under Schedules 485, 489, 490, 491, 492, and 495 (Transmission access service).

- PacifiCorp Transition Adjustments Tariffs

  - *PacifiCorp Schedule 294 (Transition Adjustment)* – This Schedule is applicable to all Nonresidential Consumers receiving service under Schedule 220, Standard Offer Service, Schedule 230, Emergency Supply Service or the applicable Direct Access Service Schedule except consumers electing a multi-year opt-out. The transition adjustment is the difference between the estimated market value of the electricity that is freed up when a customer chooses to leave Cost-Based Supply Service for Direct Access versus the Company's regulated price. The estimated market value of the freed up electricity is determined by running two system simulations – one simulation with the Company serving the Direct Access Consumer and one simulation with the Company not serving the Direct Access Consumer. The difference between the two scenarios is analyzed to calculate the impact on the Company's total system. The impacts are then used to determine the Weighted Market Value of the energy, which is then compared to the Customer's energy-only tariff schedule rate.

  - *PacifiCorp Schedule 295 (Transition Adjustment Three Year Cost of Service Opt Out)* – For large nonresidential consumers who have chosen to opt-out of the PacifiCorp's Cost-Based Supply Service Schedule 201 for a minimum three-year period and who currently receive Delivery Service under Schedules 47, 48, 747, or 748 or consumers who receive service under Delivery Service Schedules 30, 47 and/or 48 or 730, 747 and/or 748 under a single corporate name with meters of more than 200 kW of billing demand at least once in the previous thirteen months that total to at least 2 MW. Total eligible load of 200 MW will be accepted under this schedule. Transition Adjustments for each three-year period are specific to its applicable enrollment period. The consumer must elect to purchase energy from an ESS (Direct Access Service) for all of consumer's points of delivery under this schedule.

  - *PacifiCorp Schedule 296 (Transition Adjustment Five Year Cost of Service Opt Out)* – For large nonresidential consumers who have chosen to opt-out of the PacifiCorp's Cost-Based Supply Service Schedule 201 for a Five-year period and who currently receive Delivery Service under Schedules 47, 48, 747, or 748, or consumers who receive service under Delivery Service Schedules 30, 47, and/or 48 or 730, 747, and/or 748 under a single corporate entity with meters of more than 200 kW of billing demand at least once in the previous thirteen months that total to at least 2 MW. Total eligible load of 175 aMW will be accepted under this schedule. Transition Adjustments for each five-year period are specific to its applicable enrollment period. A Consumer

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Opt-Out Charge will be applicable for the five-year enrollment period. At the end of the applicable give-year period, customers who have elected this option will no longer be subject to Transition Adjustments, the Consumer Opt-Out Charge, or to charges in Schedule 200, Base Supply Service. The Consumer must elect to purchase energy from an ESS (Direct Access Service) for all of the consumers' points of delivery under this schedule.

Appendix 3 – Direct Access Summary Table (July 2015), Page 1
UM 1690 – Voluntary Renewable Energy Tariffs

Company	Program	Schedules	Enrollment Window	Cap	Eligibility	Payments/Credits and Notice to Return to Cost-based Service
PGE	One-year direct access called "Alternate Pricing Plan"	532: 0 to 30 kW 583: 31 to 200 kW 585: 201 to 4,000 kW 589: > 4,000 kW 590: > 4,000 kW and aggregate to 100 aMW 128: Transition Adjustment	Mid-November Five business days	None	Non-residential customers	Ongoing valuation method under OAR 860-038-0140 Transition adjustment reflects difference between Energy Charge(s) under Cost of Service Option including Schedule 125 and market price of power, applied to the load shape of the applicable schedule.
PGE	Three- and five-years Cost-of-Service Opt-Out	*485*: 201 to 4,000 kW *489*: > 4,000 kW *490*: > 4,000 kW and aggregate to 100 aMW *491*: Street & Highway Lighting *492*: Traffic Signals *495*: Street & Highway Lighting New Technology *129*: Transition Adjustment	September All month	300 aMW	Each point of delivery in the account must have a facility capacity of at least 250 kW, and all accounts must aggregate to at least one average megawatt (aMW)	Transition adjustment reflects difference between Energy Charge(s) under Cost of Service Option including Schedule 125 and market price of power, applied to the load shape of the applicable schedule. The transition adjustment for the 3-year opt out will incorporate costs for both existing and new resources, if any, expected to begin providing service to customers during the3-year term and will be known at the time the customer opts-out.)·

Appendix 3 – Direct Access Summary Table (July 2015), Page 2
UM 1690 – Voluntary Renewable Energy Tariffs

Company	Program	Schedules	Enrollment Window	Cap	Eligibility	Payments/Credits and Notice to Return to Cost-based Service
PGE	Three- and five-years Cost-of-Service Opt-Out	*485*: 201 to 4,000 kW *489*: > 4,000 kW *490*: > 4,000 kW and aggregate to 100 aMW *491*: Street & Highway Lighting *492*: Traffic Signals *495*: Street & Highway Lighting New Technology *129*: Transition Adjustment	September All month	300 aMW	Each point of delivery in the account must have a facility capacity of at least 250 kW, and all accounts must aggregate to at least one average megawatt (aMW)	Transition adjustment reflects difference between Energy Charge(s) under Cost of Service Option including Schedule 125 and market price of power, applied to the load shape of the applicable schedule. The transition adjustment for the 5-year opt out will reflect only those resources that have been approved by the Oregon Public Utilities Commission (OPUC); however, it will be adjusted during the 5-year term to reflect the costs associated with any new generation resources approved by the OPUC during that time period.)
PacifiCorp	One-year Direct Access Delivery Service	723: Small Nonresidential 728: 31 to 200 kW 730: 201 to 999 kW 741: Irrigation <1MW 747: Part I. Req. 1,000 kW+ 748: 1,000 kW+ (also lighting) 294: Transition Adjustment	Mid-November Five business days	None	Non-residential customers.	Ongoing valuation method under OAR 860-038-0140 Transition adjustment is calculated as the difference between estimated market value and Company's regulated price, based on GRID runs with and without the direct access load.

Appendix 3 – Direct Access Summary Table (July 2015), Page 3
UM 1690 – Voluntary Renewable Energy Tariffs

Company	Program	Schedules	Enrollment Window	Cap	Eligibility	Payments/Credits and Notice to Return to Cost-based Service
PacifiCorp	Three-year Cost of Service Opt-Out	730: 201 to 999 kW 747: Part I. Req. 1,000 kW+ 748: 1,000 kW+ 295: Transition Adjustment	Mid-November Three weeks	200 MW	1,000 kW+ or multiple meters of 200kW+ which aggregate to at least 2MW.	Three-year fixed transition adjustment, with base rates (Schedule 200) applicable and updated in any rates case during the three year transition period.
PacifiCorp	Five-year Cost of Service Opt-Out*	730: 201 to 999 kW 747: Partl. Req. 1,000 kW+ 748: 1,000 kW+ 296: Transition Adjustment	Mid-November Three Weeks	175 aMW	1,000 kW+ or multiple meters of 200kW+ which aggregate to at least 2MW.	Five-year fixed transition adjustment, with fixed generation rates (Schedule 200) applicable and updated in any rates case during the five year transition period. Five-year fixed Consumer Opt-Out Charge applies to the five year enrollment period. Transition Adjustments, Consumer Opt-Out Charge and fixed generation rates (Schedule 200) end after five-year period; consumer continues service from ESS. Four year notice required to return to cost-based service. If Consumer gives notice to return within the five-year transition period, Opt-Out Charge will cease after the date of the official notice; Transition Adjustments will continue to apply during the remainder of the applicable period.

*PacifiCorp five-year program is required under Order No. 15-060; the first enrollment window commences November 2015.

WORLD RESOURCES INSTITUTE

ISSUE BRIEF

UPDATED AUGUST 2015

EMERGING GREEN TARIFFS IN U.S. REGULATED ELECTRICITY MARKETS

LETHA TAWNEY, JOSHUA N. RYOR

INTRODUCTION

Electricity customers—from residential to large industrial—want to go above and beyond the amount of renewable energy currently offered through the electricity grid. Apart from environmental concerns and reputational advantages, greater use of renewable energy might allow them to reduce their electricity bills and protect themselves against volatile fossil fuel-based power prices. The Corporate Renewable Energy Buyers' Principles, representing 20 million megawatt-hours (MWh) and growing of renewable energy demand per year by 2020, is an example of this emerging trend to buy more renewable energy. As the Principles make clear, such customers want more than just the Renewable Energy Certifications (RECs) that allow them to claim credibly that they are using green power—they also want access to the long-term, fixed-price structure of renewable energy.

Utilities are weighing how to meet this evolving customer interest in renewable energy. Outside of the existing competitive electricity markets, utility renewable energy or "green pricing" programs have typically provided only RECs at an additional cost. Because they offer only "unbundled" RECs, separate from energy, these programs do not usually provide a fixed cost of energy as protection against volatile fossil fuel prices. Green tariffs, or riders, are an emerging option in markets where there is no functional retail electricity choice to access fixed price renewable energy. These programs, offered by the local utilities and approved by the state public utility commissions (PUCs), allow eligible customers to buy both the energy from a renewable energy project and the RECs. Green tariffs cater to customers' preference for a more direct financial connection to nearby renewable energy projects. They can also offer greater economic value to customers than unbundled RECs alone.

Through green tariffs, traditional utilities may be able to offer renewable energy services as attractive as what buyers are able to access in competitive markets or through third-party-financed "behind-the-meter" renewable energy services. Green tariffs may also prove to provide greater flexibility and lower transaction costs, given utilities' expertise and decades of experience in integrating generation technologies, aggregating customer demand, and reliably delivering least-cost resources.

Green tariff design considerations for utilities and regulators should include how to "set [fair and equitable] prices [which allow utilities to recover their costs], build a portfolio of resources, maximize both the customers' long-term commitment and their access to flexibility, mitigate the risk of stranded renewable energy assets, and consider both existing and new loads..."[1] Utilities and regulators must also protect non-green tariff customers from unfairly shouldering costs arising from implementation of the green tariff. However, there might be some costs that can justifiably be shared by all customers if they lead to system-wide benefits (for example, reduced congestion) or positive externalities (for example, reduced emissions). This depends on the local circumstances.

The following table is a compilation of several green tariff proposals and offerings for commercial and industrial customers in regulated markets in the United States. WRI's compilation utilizes expert partners' knowledge of existing and emerging green tariffs. The table excludes green pricing programs that rely on RECs but have no energy component. It also excludes utility programs that can be classified as community choice aggregation (loosely defined as tariffs where multiple customers are virtually net-metered against a share of a local renewable energy project). California's SB 43—Green Tariff Shared Renewables Program—is open to commercial customers, but caps any individual customer at 2MW of demand. This size limitation has led to its exclusion from this table because all the other tariffs listed allow individual customer demand above 2MW. However, lessons applicable to large energy customers might perhaps be learned from this program and community choice aggregation in general.

The design considerations listed above, and articulated in the Buyers' Principles, helped to shape the criteria and characteristics highlighted in the table. They include: customer costs, facility flexibility, contract time commitment, program size limits, and risk management, among others. These are the characteristics that most often drive customers' purchasing decisions.

This list is regularly updated, but for complete and up-to-date details of each green tariff, see the appropriate docket or filing number or contact the offering utility.

Utility — State	Puget Sound Energy — Washington (Planned for Fall 2015)	Rocky Mountain Power — Utah	NV Energy — Nevada	Duke Energy — North Carolina	Dominion Power — Virginia
TARIFF NAME	N/A	Service From Renewable Energy Facilities – Schedule 32	GreenEnergy Rider – Schedule NGR	Green Source Rider – Rider GS	Renewable Energy Supply Service – Schedule RG
TARIFF TYPE	New tariff	New tariff	Rider	Rider	Rider
PILOT SIZE/ PERIOD	Not defined yet, unknown whether a limit will be set First project will be ~40,000 MWh per year	Capped at 300 MW total peak delivered to all customers PUC can increase without returning to the legislature	Capped at 250,000 MWh although NV Energy can choose not to count special contracts against the total	Capped at 1,000,000 MWh or three-year enrollment period, whichever occurs first	Capped at 240,000 MWh, 100 customers, or three-year enrollment period, whichever occurs first

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Utility — State	Puget Sound Energy — Washington (Planned for Fall 2015)	Rocky Mountain Power — Utah	NV Energy — Nevada	Duke Energy — North Carolina	Dominion Power — Virginia
TARIFF/ CONTRACT STRUCTURE	Utility signs fixed price, 15-year contract with RE generators Utility creates tariff for service agreement with known energy costs for RE resources	RE facility is selected by the customer, not RMP Two contracts: 1) between RMP and the customer and 2) between RMP and the RE facility Same pricing and duration for both contracts RMP takes ownership of the electricity from RE facility	Two options for commercial customers: 1) to contract directly with NV Energy for 50 or 100 percent of monthly electricity usage or 2) customer and NV Energy enter special contract for dedication of new or existing RE resources to the customer (this table focuses on option 2, which bundles energy and RECs)	Customer makes request and commitment for a certain amount of RE Duke will dedicate output from one of its facilities or procure RE through a PPA with an independent facility to try to match the source with a customer's annual demand, RECs and contract term If supplier fails to deliver, Duke will attempt to find a replacement	Customer can request a specific RE facility/ resource and RE purchase size Dominion negotiates and enters into a Renewable Energy Purchase and Sales Agreement (REPSA) with the generator Second contract between Dominion and the customer assigns costs and risks to the customer
CUSTOMER COST STRUCTURE	Energy component in standard schedule is replaced by the RE contract with the utility, but other tariff elements and rates (for example, demand charges) remain the same Declining penalty for early exit	RE is charged at the price negotiated between the customer and the developer of the RE facility; distribution and delivery charges are priced at rates specific to this tariff. Daily demand charges apply to the renewable energy contract capacity Supplemental energy and supplemental demand priced at rates from the otherwise applicable tariff for the customer Services are balanced at every 15 minute interval for every meter; excess generation in the 15 minute block cannot be credited to the customer or allocated to another meter	Standard "otherwise applicable rate schedules" apply plus the full cost of the specific facility in kWh (the Renewable Resource Rate (RRR)) The NGR Rider rate for small customers is the 12-month average cost of the utility RE resources less the base tariff energy rate and the standard "temporary RE development rate" (recalculated quarterly) If the RRR is less than the NGR rate, then the NGR rate applies to the special contract customers	Standard general service tariff and all riders apply plus the total cost of the PPA and RECs (Rider GS) determined on an hourly basis Customer receives bill credit for "all in" avoided capacity and energy costs for the RE produced over the month to offset the premium Early termination fee equal to the net present value of the remaining PPA cost	Customer purchase price is the REPSA price minus the energy component of Dominion's General Service (GS) tariff rate; the rest of GS rate charges apply Demand side management costs and all other riders still apply to the customer, except the fuel surcharge rider
ADMIN. FEE	Administrative costs are passed through to the customer because they are included in the tariff rate	Administrative charges of $150 per month for each delivery point (meter) and $110 per generator per month, irrespective of the number of delivery points	Cost recovery will be determined in the PUC review of the special contract	$2,000 application fee $500 fee per meter, plus 0.02 cents per kWh surcharge on RE purchased	$500 per meter per month

Appendix 4

Utility — State	Puget Sound Energy — Washington (Planned for Fall 2015)	Rocky Mountain Power — Utah	NV Energy — Nevada	Duke Energy — North Carolina	Dominion Power — Virginia
VALUE OF RE PRICE CERTAINTY	The customer is shielded from rate increases that apply to the energy component, including power cost adjustments, etc. embedded in the energy component Not shielded from changes to monthly fees, demand charges, etc. If the RE price in the service agreement falls below the utility mix energy price, the benefits accrue to the customer in the form of lower rates	New schedule that could theoretically deliver lower cost than standard retail rates Reduced exposure to fuel price volatility to the degree that energy is procured from RE facility, subject to backfilling RE generation with supplemental and backup service	Unclear in the filing whether the NGR rider can ever be negative and appear as a bill credit against the otherwise applicable rate schedules; indications thus far are that this might not be possible	No exemption from the fuel price surcharges or any other riders; however, the allocation of actual fuel costs to GS customers as a class will be reduced by the fuel-related component of the avoided energy credit and the balance of actual fuel costs allocated instead to non-GS customers Bill credit for the avoided cost of the RE cannot exceed the actual cost of PPA and RECs	Rider is on top of the GS tariff, but the customer is exempted from the fuel surcharge rider
CUSTOMER RIGHT TO VETO OFFER/ CONTRACT	Customers can choose not to subscribe to the offering, but do not engage in the PPA negotiations	Customers bring the PPA to RMP and lead on the PPA negotiations	Not explicit in the filing, but customers can refuse to enter the special contract with NV Energy	Duke will negotiate with the facility, but customers have the right to review the offer and the estimated bill credit and not go forward	Dominion negotiates with the facility and customers; customers have veto right with no impact on Dominion
BUNDLED RECs MANAGEMENT	Retired on behalf of the customer The customer may also join WREGIS at their expense and the RECs will be transferred	REC contracts are directly between RE facility and the customer	RECs will be retired against the RPS requirement for the customer's load first RECs will then be retired for the incremental energy sold under the NGR beyond the RPS requirement	Retired by Duke on behalf of the customer using NC-RETs	Retired or transferred to the customer, but not sold on behalf of the customer
CUSTOMER FACILITY FLEXIBILITY	Movable from meter to meter for customers moving within the service territory (for example, opening and closing stores, offices, etc.)	RE facility can service multiple customers or customer meters; a customer served by multiple RE facilities will pay a monthly fee for each facility	Not defined in filing but designed primarily for large facilities rather than retail meters	Customers do not expect Duke to allow moving contracts between meters	One customer is limited to RE from one RE facility

Appendix 4

Utility — State	Puget Sound Energy — Washington (Planned for Fall 2015)	Rocky Mountain Power — Utah	NV Energy — Nevada	Duke Energy — North Carolina	Dominion Power — Virginia
CONTRACT TIME COMMITMENT	Ten years, with an option to extend for an additional five; provide notice in year seven if they choose to opt for the five- year extension	Negotiated—identical for both contracts	Negotiated but not less than two years	Negotiated—3-15 years	Determined by the REPSA and customer requirements, 10 years suggested
CUSTOMER LIMITATIONS/ ELIGIBILITY	Commercial, non-residential meters on Schedules 24, 25 and 26 eligible; includes most commercial customers Schedule 24: up to 50 kW Schedule 25: demand greater than 50 kW up to 350 kW Schedule 26: demand greater than 350 kW	Only customers otherwise on Schedules 6, 8, or 9 Schedule 6: non-residential customers with a load less than 1,000 kW (distribution voltage) Schedule 8: load of 1,000 kW or more (distribution voltage) Schedule 9: high voltage customers Customers must contract for 2MW or more and cannot contract for more capacity in MW than their peak demand. This limitation combined with the 15 minute matching of resource to demand means the tariff likely limits the ability to reach a 100% renewable energy goal.	Northern Nevada: GS-2 meters or larger, demand between 50 and 500 kW or monthly usage larger than 10,000 kWh Southern Nevada: LGS-1 meters and larger, monthly usage larger than 3,500 kWh Customers can subscribe a portion or all of their energy consumption	Non-residential customers, OPT-V tariffs only (previously OPT-G,OPT-H, OPT-I) OPT-V: Optional power service, time of use with voltage differential New loads of at least 1 MW since July 30, 2012	Non-residential, commercial customers on GS-3 and GS-4 tariffs Demand greater than 500 kW Customers contract for an individual purchase of RE between 1,000-24,000 MWh per year
AGGREGATION OF CUSTOMER FACILITY DEMAND	Customer selects which meters (one to all) to commit to the new tariff	Aggregation of meters by a single customer is allowed to meet the 2MW minimum, but fees and power produced/used in 15 minute usage blocks are by meter	Not explicit in the filing but limitations are described by meter, so unlikely	Not explicit in the filing but limitations are described by meter, so unlikely	Aggregation is not allowed
IMPACT ON NET-METERING (ONSITE RESOURCES)	Customers can continue to reduce consumption through energy efficiency, and by self-generation and net-metering	Net-metering of electricity purchased from the facility by customers is not allowed	NV Energy is not prohibited from also accepting net-metered energy from customers	No limitations defined in the filing	Customers cannot participate in this tariff and also net-meter

Appendix 4

Utility — State	Puget Sound Energy — Washington (Planned for Fall 2015)	Rocky Mountain Power — Utah	NV Energy — Nevada	Duke Energy — North Carolina	Dominion Power — Virginia
RE FACILITY LIMITATIONS/ ELIGIBILITY	Projects need to be interconnected with the distribution grid in the service territory Projects can be IPPs or utility-owned	Limited to facilities in Utah Can be owned by the customer, the utility, a third party, or a combination	The power can be owned or procured by NV Energy No geographic limitations seem to be explicitly set	Duke Carolina RE facility or independent RE facility RE facilities operational on or after 2007 No geographic limitations seem to be explicitly set, but filing and discussions imply North Carolina facilities	RE facilities within the PJM Interconnection
COMMERCIAL RISK MANAGEMENT	If undersubscribed, excess energy will be dispatched into the larger system at state-approved avoided cost (PURPA rate) and the RECs used in the green power pricing program	Customer must prove reasonable credit Contract with the RE facility terminates if customer defaults	All contract risk falls on the customer PUC must approve the contract demonstrating benefits to the customer, NV Energy, and non-participating customers	Customer must provide a letter of credit, surety bond or other form of security for payment of all costs (PPA, RECs, etc.) All contract risk falls on customer	All contract risk falls on the customer, including risk or liabilities assigned to Dominion in the REPSA
PUC PROCESS	Not yet proposed to the PUC, in development and expected Spring 2015	Approved March 20, 2015 Directing legislation, SB 12 was effective May 8, 2012	Approved September 9, 2013 NV Energy applied to extend the special contraction option of the rider to Southern Nevada via docket 14-0631, the PUC approved November 13, 2014	Approved December 19, 2013	Approved December 16, 2013
STATUS/ RE DEALS SIGNED	PPA signed with new IPP project within service territory but construction delayed MOUs signed with key customers who have indicated interest	RMP has proposed a Subscriber Solar product in Docket 15-035-61 that Schedule 32 customers could access in order to simplify procurement.	Apple Fort Churchill project approved in docket 13-07005	Customers have applied and are in negotiations, but none have signed to date	Dominion reports that the rider has not been used to date
DOCKET INFORMATION	N/A	Docket 14-035-T02, implementing SB 12. Look for a forthcoming WRI case study on RMP in the fall of 2015	Docket 12-11023 (Northern Nevada) and 14-06031 (Southern Nevada)	Docket E-7, Sub 1043	Case PUE-2012-00142

Appendix 4

ENDNOTES

1. Tawney, Letha. 2014. "Above and Beyond: Green Tariff Design for Traditional Utilities." Working Paper. World Resources Institute, Washington, DC. Available online at: wri.org/publication/green-tariff-design

GLOSSARY OF TERMS

GS	General service
IOU	Investor-owned utility
IPP	Independent power producer, a company that generates and sells power
NGR tariff/rate	Name given to NV Energy's green tariff and rider rate
OARS	Otherwise applicable rate schedule for customers served by NV Energy
OPT tariff	Duke "Optional Power Service, Time of Use" tariff structure
PJM	Pennsylvania-New Jersey-Maryland Interconnection, regional transmission organization (RTO) that coordinates the wholesale electricity in parts of 13 Mid-Atlantic and Midwestern states and DC
PPA	Power purchase agreement
PUC	State public utility commission which regulates the electric utilities in a given state
PURPA	The Public Utility Regulatory Policies Act is a federal law that requires utilities to purchase renewable energy produced by certain qualifying facilities (QFs), such as wind, solar, geothermal and small hydroelectric resources; avoided cost (the cost a utility avoids as a result of the QF) forms the basis for determining QF purchase pricing
RE	Renewable energy
REC	Renewable energy certificate attributed to renewable generation under state RPS requirements
REPSA	Renewable Energy Purchase and Sales Agreement between Dominion and renewable energy generator
Rider	Additional rate applied to an electricity tariff
RMP	Rocky Mountain Power
RPS	Renewable Portfolio Standard, i.e., state-law requirements as to the proportion of energy sold by a regulated utility that must come from specified types of RE generation
SB	Senate bill
Tariff	Electricity pricing, and price structure, charged consumers

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ABOUT THE AUTHORS

Letha Tawney is the Director of Utility Innovation and the Polsky Chair for Renewable Energy at WRI.

Contact: ltawney@wri.org

Joshua N. Ryor is a Research Analyst with the Global Energy Program at WRI.

Contact: jryor@wri.org

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WORLD
RESOURCES
INSTITUTE

10 G STREET NE
SUITE 800
WASHINGTON, DC 20002, USA
+1 (202) 729-7600
WWW.WRI.ORG

978-1-56973-804-7

UM 1690 – Voluntary Renewable Energy Tariffs
Phase 1 Study – Summary of Responses

I. How should a Voluntary Renewable Energy Tariff (VRET) be defined and designed? *(context/general issues)*

1. **What are the essential features of such a tariff (e.g. ability to purchase power at a long term, fixed rate)? If the Commission were to allow VRETs, would more than one type of VRET design help to satisfy diverse customer demands?**

- **Renewable NW**: Must drive renewable energy development that is incremental to existing policies like RPS. Must be attractive to customers, which can mean something different to each customer. Some customers may have energy expertise to make deals with specific projects. Other customers may want to check the box provided by a utility, and still other customers want more RE supply that is closely connected to their utility. Some customers evaluate financial risk such that they are willing to pay a premium against current costs, while others are less price sensitive and more heavily focused on environmental claims. One feature that is not essential to the VRET is having renewable energy supply scheduled and accounted for precisely to match the specific customer or customers' load. Customers could pay the supply costs and then crediting the total quantity of energy delivered over the billing period against the customer's energy cost with an additional credit for system capacity contribution – thus reducing administrative burden and costs while maintaining VRET customers' responsibility for system costs. Having at least two distinct VRET designs would capture customer preferences: (1) enable customers with specific energy preferences and expertise to connect to specific projects (easier to implement quickly) and (2) simple path to sign up for the utility's aggregated VRET portfolio (more scalable and capable of capturing customer choice with lasting influence on utility portfolio.
- **PGE**: No standard set of essential features. Offer VRET to large non-residential customers, but maintaining flexibility in VRET designs may help satisfy different customer preferences.
- **Pac**: Customer needs are different and utilities should have flexibility in bringing forward VRETs, which is important to create distinct VRETs for distinct sets of customers – e.g. subscription based offering for smaller customers or a specialized bilaterally negotiated offering for a larger customer. No identification of essential features, but customers have said "certainty," which could be addressed through set terms that guarantee the VRET for a term longer than currently available in existing tariffs.
- **Shell**: VRET is not necessary as long as there is a robust direct access market. Customers can and show purchase renewable supplies (up to 100% of their energy requirements) from third party suppliers, but Commission must adopt rules that require the utilities to facilitate direct access transactions. If a VRET is adopted, it should minimize participation by utilities in the incremental renewable energy purchase from third parties and sale to customers. A VRET that includes the utility in the active purchase and sale of renewable energy would cause the utility to "compete" against its own default bundled sales services, likely resulting in cost-shifting. Because of the competitive advantages of incumbency, a VRET would have a negative impact on the development of a competitive retail market. Essential features of a VRET should be: (1) third party renewable energy developers and suppliers will negotiate contract terms, including price, quantity, term, with participating customers, (2) electric utility will purchase the renewable energy from the third party developers/suppliers and sell the renewable energy to participating customers, at the same price, which is fixed by the Commission, (3) agreed upon price between the renewable supplier and customer will be settled between the supplier and customer, (4) participating customers will pay the utility an "indifference" charge (reflecting the utility's cost of integrating the renewables) along with their bundled cost-of-service price, (5) utility remains responsible for providing bundled sales service to participating customers, (6) failure of the renewable energy supplier to perform its delivery obligation is addressed through standard contract between energy supplier and utility.
- **WRI**: The 19 signatories of the Corporate Renewable Energy Buyers' Principles have highlighted that they value: cost-competitiveness between traditional and renewable energy rates, access to longer term fixed prices, access to new renewable energy projects close to operations, access to RECs, simplified transactions, and increased access to third party financing for projects. But customers have a wide variety of load profiles and internal capacity to procure energy. Allowing more than one type of VRET design will help satisfy diverse customer demands and maximize opportunity to further development renewable energy.

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- NIPPC: Essential features include (1) allows customers a voluntary option to purchase renewable energy on long-term basis at a fixed or negotiated price not subject to fluctuation based on a utilities' cost of service – the term "voluntary" refers to prospective customers and not to whether the utility desires to offer such service; (2) must be open to competition and present a level playing field where utilities should not be able to create terms or conditions that ESSes are not permitted to create; (3) must not shift costs to non-participants or make use of facilities/services in rate base.
- ICNU: Must ensure that all costs and benefits of the tariff are borne by the participating customer and must not interfere with development of competitive markets.
- Noble: Essential features are a tariff product that matches renewable generation source to customer sink on an hourly or shorter schedule basis with the IOUs providing load following/back up service. How that product is priced or the term of the tariff is at the IOU's discretion based on cost of service studies and subject to the PUC parameters and tariff approvals. Any renewable product that is not source-to-sink on a real time basis is an unbundled REC sale, which has been excluded from consideration in this proceeding.
- ODOE: No essential features, but Commission should explore how multiple VRET types might interact within the market. It would be informative for the study to explore whether or not multiple designs of a VRET could be offered by the VRET provider and what interaction may occur.
- CUB: Process thus far cannot yet define the essential features of a VRET. While there is a better sense of needs of some large customers, that sense is narrow and limited to a handful of customers.

2. **Should a regulated utility continue to plan for VRET load through integrated resource planning? Should VRET customers be included in a regulated utility's total retail sales?**

- Renewable NW: Yes, IRPs should examine VRET load. In the design where specific customers with expertise connect to specific projects, it could be treated like direct access demand is currently treated (except on the energy side of the load-resource balance equation). In the design with an aggregated VRET product, there would need to be more discussion on how VRET load planning could be integrated into resource planning and procurement.
- PGE: Yes, PGE required to provide capacity resources for VRET load that is needed because of intermittent resources.
- Pac: IRP is a tool to identify resource need for the integrated system that forecasts total load obligations compared to current and potential new resources. VRET role in IRP depends on magnitude and predictatbility of load, VRET resource, and term of VRET commitments. If under a VRET, utility retains obligation to provide cost based service then for a VRET with a short term (e.g. one year), it would be appropriate to continue to plan to serve participating customers. For long term commitment (e.g. five years or more), VRET load may be removed from load obligations. Alternatively, depending on utility relationship with VRET resource (e.g. if utility owned or contracted), VRET may need to be included in IRP to offset load obligations and capture any integration requirements associated with different between VRET load and VRET resources. How are if VRET load is included in total retail sales depends on how retail sales number will be used. It should be consistent with RPS without double-counting. Example – if VRET load is served by resources that are RPS-eligible, that load should not be included in the utility's retail sales for purposes of determining RPS compliance obligation. If VRET load served by RPS eligible resources is included in retail sales, perverse outcome is that VRET customers may increase utility's RPS obligation while being served with RPS eligible resources, which may lead to increase RPS compliance costs for non-VRET customers.
- Shell: No, customer and its renewable supplier should be responsible for planning for customer's energy needs. Load should be treated like direct access load.
- WRI: Utility should consider VRET load in IRPs, like they consider direct access load, energy efficiency trends, and self generation. VRET load projections could support renewables-centric procurement when additional capacity requirements are identified in the IRP.

- **ICNU**: Including VRET customers in total retail sales could create potential for cost shifting to non-participants.
- **Noble**: Answer depends on whether IOU is willing to let VRET customers return to bundled utility service and if so the terms of such a return. Currently, on PGE allows certain classes of direct access customers enter into the type of long term opt out of cost of service rates that has been recognized as warranting exclusion of those customers from consideration in the load PGE must service in its IRP. It would be reasonable to treat the VRET load similarly and to exclude the VRET load from resource planning if the VRET customer is required to make a long term opt out and provide similar notice to return to cost of service rates. If it is determined that VRET customers are excluded from planning in the IRP, then those customers should also have the right to freely move off the VRET tariff and to direct access without first returning to cost of service rate or paying additional transition fees.
- **ODOE**: IRP load forecasts should include consideration of VRET programs. If under the VRET model the customer's load is no longer part of the utility's load, the IRP should include within its risk analysis the possibility of the load returning to the utility. All of the models being considered would affect either the utility's load forecast or its resource needs. Electricity purchased by a VRET customer from a regulated utility is a retaile sale and show be included in the regulated utility's total retail sale.

a) Should VRETs be considered for all non-residential customers or only a subset of non-residential customers (e.g. only large customers)?

- **Iberdrola**: consider same demand threshold as direct access – 30 kw demand
- **Renewable Energy Markets Association**: Customers of all sizes should be eligible to participate in a VRET.
- **Renewable NW**: Eventually, all non-residential customers and later reconsider residential customer choices with POC. Initially, consider smaller subset of larger customers, including those with multiple locations, in a 150 MW (or greater) pilot program.
- **PGE**: No, to minimize administrative burden there should be a threshold for eligibility.
- **Pac:** Maintain flexibility and don't limit VRET to only certain customers. But, supports eligibility criteria and caps on VRET offerings that reflect the distinct needs of distinct classes of customers.
- **Shell**: Should be available for all non-residential customers.
- **WRI**: There is demand from large individual loads, large aggregate loads, and smaller businesses. VRET pilot could start with one subset, but maximizing opportunity to drive renewables development argues for allowing utilities to expand VRET availability over time, particularly when new capacity needs are identified in the IRP.
- **Center for Resource Solutions (CRS)**: All customers who may wish to participate in the VRET should have the option. Midsized companies are just as interested in using renewable energy as larger companies. Mid-sized companies want to find ways to support their clean power commitments and distinguish themselves from competitors by using renewable energy.
- **NIPPC**: VRET should be considered for the same subset of non-residential customers as the utility allows under its Direct Access Tariff. Utilities should be encouraged to make direct access service available to a wider subset of non-residential customers, and/or have a special "VRET Direct Access Service" available to a larger range of customers, which would encourage increased development of renewable resources.
- **ICNU**: All non-residential customers should have the option to voluntarily select a VRET.
- **Noble**: Should be available to all non-residential customers regardless of size. However, criteria that affects availability should be the same between VRET and direct access. Example – if a multi year VRET is available to customer who are smaller than the minimum size required for the utility's multi-year direct access program, then direct access providers should be permitted to offer a multi-year renewable energy product (comparable to the VRET) to those smaller customers who qualify for the VRET but do not currently qualify for multi-year direct access. This would promote the further development of renewable resources, while at the same time not harming Oregon's competitive retail market place.

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- ODOE: Eligibility should not be limited. Enrollment should be allowed by all non-residential customers. There is clear, demonstrated interest from small commercial customers who have strong participation in the existing voluntary programs. Expanding the program to all non-residential customers would allow the program to benefit from economies of scale.

b) **Should there be a cap on the amount of load that can be served under a VRET to protect against risk of large amounts of load leaving the existing cost-of-service system (e.g. the 300 average MW cap for direct access in PGE's 400 series cost-of-service opt-out schedules)?**

- Iberdrola: Generally, neither VRET nor Direct Access should be subject to caps. But because there is a current Direct Access cap, VRET should have a symmetrical cap.
- Renewable NW: Should experiment with smaller load segments initially, so no less than 150 MW. But all parties should strive to build a scalable VRET structure to capture all demands for new renewables.
- PGE: With regard to PGE's proposed models, customers would continue to pay PGE's cost of service, so there is no need to cap the amount of load that can be served. However, eligible load could be capped to pilot the VRET concept and determine degree of customer interest and participation. Unlike direct access, utility is serving load and risk can be assessed through IRP.
- Pac: Yes, participation caps for VRET offerings available to larger customers. It depends for other potential caps on other VRET offerings. Example – a cap may be tied to the type of resource or resources identified to serve the load. Preserving utility flexibility to propose program caps tailored to needs of a particular VRET ensures utilities are able to respond to customer need and attract VRET participants. Cap may also be appropriate to assess potential for unanticipated cost shifting to non-VRET participants.
- Shell: No.
- WRI: Other jurisdictions have capped VRET type programs, sometimes through soft caps (Nevada and Utah) that can be raised without a new phase in the program. In Oregon, caps could be set by utility based on, for example, short term market transaction in the prior year or anticipated capacity shortfalls identified in IRP. This approach would limit risk of impacts on non-participating customers but could allow program to grow in measured way over time. This could also address questions of transition costs as new renewable energy resources would not displace existing investments in generation, but fill gaps in capacity instead.
- NIPPC: Subject to a level playing field with utilities, there should be no cap on the amount of VRET load. If VRET is successful, it will promote job growth and decrease the state's carbon footprint, which should not be artificially limited.
- ICNU: No position on cap, so long as stranded costs are not imposed on non-participants.
- Noble: Assumes that the VRET is a type of utility offering that will be designed to capture all fixed and variable costs, as well as any stranded costs associated with the tariff rate. If so, there should theoretically be no need to "cap" the amount of VRET load. However, if there is not a cap for VRET load, this could result in discriminatory treatment of direct access suppliers that currently are only allowed to make renewable energy offerings subject to strict program caps. If no cap is used for the VRET, direct access providers should be permitted to offer multi year renewable energy products that are comparable to the VRET that is not subject to current direct access program caps.

3. **What portion of a customer's load should a VRET be able to serve? All load? Partial load? Service at a given Point of Delivery (POD)? Should VRET customers be able to aggregate multiple sites/PODs?**

- Iberdrola: Flexibility in both load share and third party aggregation like Direct Access so that VRET is available to greater range of customers than a full-load requirement.
- Renewable Energy Markets Association: Customer should have a range of options for selecting a level or proportion of their energy that would come from renewable sources. Many green power marketers have

adopted a 25% based block structure for purchases, allowing consumers to reach 100% of their energy consumption. Options like this would reduce customer confusion, increase green power marketability, and allow customers to tailor green power purchases to their needs.

- **Renewable NW**: Should be flexible enough to serve all or part of a customer's load at any POD and should enable aggregation of multiple PODs.
- **PGE**: Yes, customers should be able to aggregate and VRET should serve whatever amount of load customer needs.
- **Pac:** Premature to determine this now because it may exclude versatile and innovative VRET options. This can be determined as part of Commission consideration of a specific VRET offering. However, any VRET load during specified time periods not simultaneously served by a VERT resource should be subject to a PUC approved tariff.
- **Shell**: VRET should allow participating nonresidential customers to meet any portion of its load (up to 100%) with incremental renewable supplies above and beyond the "baseline" provided by utility bundled sales service.
- **WRI**: Other jurisdictions are enabling site aggregation, including two proposals allowing aggregation of small commercial meters. Flexibility is key for meeting wide range of customer renewable energy needs and maximizing opportunity to drive further development of significant renewable energy. There is no reason to presume load aggregation would increase risk of negative impacts and impacts could be reduced by diversifying VRET load, so the default could be to enable flexibility.
- **Center for Resource Solutions (CRS)**: Customers should have a variety of options for percent of load and block products to enable more customers to participate in the program. All customers should be offered a 100% option to addition to other options.
- **NIPPC**: Subject to a level playing field with utilities, VRET customers should have full flexibility to use VRET service, including ability to aggregate multiple sites and points of delivery for VRET service and to take full or partial load service at any such point.
- **ICNU**: All reasonable options should be available to customers.
- **Noble**: If adopted, VRET should allow customers to serve all load with POD aggregation consistent with offerings currently allowed under direct access.
- **ODOE**: VRET customers should be able to serve up to 100 percent of their load with VRET power. A key issue will be how to consider fossil fuel resources that are used to shape or firm power from variable renewable generation. Given this consideration, even if the VRET product is intended to comprise 100 percent bundled RECs, it may or may not be possible for VRET customers to claim 100 percent renewable power. VRET customers should be able to aggregate multiple sites/PODs. The VRET is a customer-driven product that should be designed in a manner that will encourage market uptake. Some customers seeking a VRET product have indicated aggregation of multiple sites as an important product feature and will increase ease in enrollment for their organization. The benefit for aggregating multiple sites will be higher subscription rates for the VRET provider. The administrative costs of the aggregation should be recovered from VRET customers.

4. Should VRET load be met with multiple renewable resources that are aggregated? If so, how should the regulated utility disclose the renewable resources provided as an aggregated product?

- **Iberdrola**: Yes, aggregation would make bundled RE and RECs more efficient and cost-effective. Yes, disclosure to public, VRET customers, and PUC through utility fuel-mix disclosures, delivery schedules (for bundled and firm/shaped products), and REC retirement information from WREGIS.
- **Renewable NW**: Question assumes single VRET load with centralized service from utility (c/d type model), where, yes, resources could be aggregated to serve aggregated customer demand. Disclosure depends on manner of procurement, which could be communicated as a proportional mix supplied to each participating customer. If a b/x type model with specific customers connected to specific projects, customer should be able to use multiple renewable resources to offset customer's preferred amount of system energy offset.

- PGE: Yes, aggregated renewables should be an option. As part of service agreement or tariff filing, utility may disclose what renewable resources are included in that aggregation.
- Pac: supports variety of opportunities, including use of aggregated renewable resources. VRET load *could* as opposed to *should* be met through aggregated renewable resources. If there is a contract (with Pac or a third party) for renewable resources, they should identify specific RPS eligible resources or a certified report.
- Shell: Participating customer and renewable energy supplier should be allowed to meet the committed VRET load with any combination of renewable supplies, from multiple sources. The renewable supplier should be required to identify, for the utility, the renewable resources aggregated for one or more customers.
- WRI: Resources aggregation would provide more customers flexibility and could offer efficiencies but should be handled so that competition produces a least cost options to maximize VRET to drive renewables development.
- Center for Resource Solutions (CRS): Green-e Energy program requires companies selling certified products to provide information to customers prior to sale disclosing resource types included in the product. Within 60 days of sign up to purchase the certified product, sellers must provide purchasing customers with a product content label that describes where the resources were generated. Historical product content labels also need to provided after close of the selling year and verification period to confirm that customers actually received what was advertised and what they paid for.
- NIPPC: VRET load must have ability to be met through multiple renewable resources. Any solution that limits a given load to a single renewable resource imposes unnecessary, artificial risk on the customer and power provider without commensurate benefit. The Direct Access VRET model avoids the need to address the issue of disclosure to the utility.
- Noble: If adopted, VRET should allow IOU to source the renewable energy however IOU wants to design tariff so long as the product is an hourly or less source-to-sink delivery and other applicable requirements are met.
- ODOE: Resource aggregation should be provided if customers indicate an aggregated resource mix is desired. The VRET could be offered in two configurations to customers. The first would be a product that is readily designed by the utility with a specified resource mix similar to the existing unbundled voluntary products offered by the utilities. Under this tariff structure, the resource content of the tariff could be included in the resource content label provided by the utilities under OAR 860-038-0300. The second is a specialized product to meet the goals of the customer (e.g. resource specific, distributed generation, community based renewables etc.), which fits into the broader framework. Under these circumstances, the VRET provider could market this option to customers as a possible VRET configuration and it would be up to the customer to disclose the renewable resources provided through its marketing materials.

5. Given the variability of renewable energy generation, what services should be included in a VRET to enable delivery of renewable energy (e.g. back-up/supplemental services or firming/shaping)?

- Iberdrola: Requirements for delivery/ancillary services should be same as Direct Access requirements.
- Renewable NW: Not all renewables are variable or variable in the same way. VRET model should accommodate different types of renewable generation by replacing the energy cost with the energy value (including ancillary services and other benefits) and provide a credits against fixed cost for the renewable energy project (or portfolio) capacity contribution. For renewables with intra-hour variability, standard integration charge is appropriate.
- PGE: VRET should include ancillary services to address renewable resource variability. In PGE's proposed models, PGE assumes its generation portfolio will be providing ancillary services for VRET product.
- Pac: should be the broadest possible range of services, including back up, supplemental, firming/shaping for inclusion in VRET. They are potentially critical to delivery of variable renewable resources and the utility's cost of providing these services should be considered in VRET design.
- Shell: Because customer will be bundled [cost of service] customer, utility remains responsible for necessary firming/shaping services. VRET customers could pay an "indifference charge" to protect against cost-shifting.

- **NIPPC**: Any VRET model should allow back up/supplemental services and firming/shaping through non-renewable power. The direct access model already provides for this service, allowing either an ESS to provide ancillary services directly or allowing the Commission to require that the utility provide such service (Section 860-038-0340).
- **ICNU**: VRET customers should be responsible for an allocated portion of the costs of flexible capacity and other resources necessary for integrating and firming renewables that serve those VRET customers.
- **Noble:** VRET should match renewable generation source to customer sink on an hourly or shorter schedule basis with the IOUs providing load following/back up service.

6. For comparison, with regard to *existing Direct Access* as summarized in the *VRET Models Table*:

- **CUB:** Direct access should be explored as to why it may fail to offer types of renewable energy being sought in a VRET. Any flaws or issues in the current direct access structure should be addressed or corrected.
- **Obsidian Reply**: Direct access is not a close proxy for the VRET. Direct access customers may leave and choose a renewable energy supply, but that is direct access, not VRET. VRET customers remain customers of the utility, and if the rate design is done correctly they become ever more important customer of the utility.

a) Are there service requirements (e.g. transition charges, enrollment windows, etc.) applicable to direct access that should not be required in provision of service under a VRET? If so, what is the rationale for differentiating between direct access requirements and VRET requirements?

- **Iberdrola**: No. Must ensure standard regulated service customers do not cross-subsidize VRET customers, provisions of electricity products should not be different between VRET and Direct Access.
- **Renewable NW**: It depends on VRET design. On one hand, if VRET is similar to renewable energy supply under Direct Access, then the programs should operate similarly in terms of enrollment windows, etc. On the other hand, if the VRET was a less comprehensive departure from the cost-of-service system or fundamentally integrated with IRPs or customers were continuing to pay a large portion of their cost of service demand charges, then customers may be paying all or most of what transition charges compensate. Overall, Commission should ensure a level playing field for renewable energy supply across different options designed to match different customer preferences.
- **PGE**: No need for transition charges or enrollment windows, because in PGE's proposed models, the customers are not leaving the system. The VRET customers pay cost of service rates and contribute to fixed generations costs.
- **Pac:** VRET is fundamentally different than direct access. Direct access allows customers to choose own service provider, but service is fundamentally the same as what they would otherwise receive from incumbent utility. However, VRET allows customers to choose unique terms of service to ensure generation serving customers reflects that customer's generation profile needs (100% renewable or zero emission). While both programs provide additional choice, the core purposes are different. To retain flexibility for utility to respond to customer needs, VRET offering should not be limited to an enrollment window like direct access. Although enrollment windows may make sense in direct access, for purposes of VRET, customers should be free to initiate VRET service based on timing of resources. For a large, customer-specific offerings, the VRET may require bilateral negotiations to determine exact terms of particular VRET service or resource and would not be conducive to an enrollment window. While conceptually distinct, both direct access and a VRET have potential to create similar impacts in potential for cost-shifting of fixed and variable generation costs from customers electing direct access or a VRET, to customer that do not. VRET should examine methods to address potential cost shifting concerns.
- **Shell**: Customer participation in VRET should not be allowed under more favorable terms/conditions than customer participation in direct access. If enrollment windows and transition charges are modified/eliminated in VRET, then they should also be modified/eliminated in direct access.

- NIPPC: There is no rational basis for treating VRET load differently than direct access load with respect to transition charges, enrollment windows, and related matters. However, the level of those charges and conditions imposed by utilities is artificially high and designed to limit rather than support a competitive retail market. The commission could allow utilities to offer a new tariff service under direct access specifically for renewable energy that has different levels of transition charges, enrollment windows, etc, as compared to non-renewable direct access in order to facilitate further development of renewable resources.
- ICNU: All cost protections currently associated with transition to direct access should also apply to VRET customers. Other protections may be appropriate depending on design.
- Noble: Whenever a customer leaves the utility's bundled portfolio service for direct access or a VRET, there is a possibility of stranded costs being incurred by the utility or remaining cost of service customers. Currently, the stranded costs associated with direct access elections are assessed in full to the departing customer in Oregon. And the utilities offer direct access only under strict program caps, short enrollment windows, and length notices to return to cost of service rates, among others. The express or implicit goal of these restrictions is to hold remaining customers harmless. Accordingly, to protect the competitive market, the stranded costs associated with the decision to elect VRET service need to be identified and included in the cost of any VRET product that the Commission may approve. The same or comparable terms of service applicable to direct access in order to maintain a level playing field between direct access service and a VRET need to be incorporated into the VRET – this includes all the rules that limit direct access activity (enrollment windows, notice to return, program caps, etc).

b) What "green energy" options do Energy Service Suppliers (ESS) currently offer in utility service territories under direct access?

- Iberdrola: Company is a registered ESS providing a renewable product in Pac territory. Customers and ESSes can customize products and services to meet green energy preferences. Most significant impediment is not products themselves, but implementation rules for utilities' direct access programs.
- Renewable NW: ESSes free to offer any options for energy supply that meet customers' desire, including renewable energy as a portion of the portfolio that the ESS uses to meet its customer load.
- Shell: Enhanced renewable procurement options are based on negotiations between an ESS and prospective customer. There is no limit on green energy options that can be negotiated with ESS and customer.
- YAM Services: Direct access includes certain ancillary services from an entity other than the distribution utility (Order No. 00-596)
- NIPPC: broad array of green energy options designed to meet needs of individual customers. Examples include: (1) 5 year contract to purchase all of the energy from a specified wind farm at a levelized rate, along with shaping/ancillary services provided through fossil generation; (2) fixed rate contract to meet all of an industrial customer's power requirements, including all ancillary services, with all generation from renewable sources (and/or with purchase of voluntary carbon offsets for ancillary services that cannot be met with renewable power) for a fixed prices for 20 years, with a customer option to terminate service on two years notice, and subject to a minimum payment requirement by the customer; (3) 25 year contract to purchase renewable power at a rate fixed for five year terms, and adjusted at the end of each term based on the changes to the consumer price index. To the extent a customer wants a specific structure, NIPPC members discuss potential options. There are very few limitations facing an ESS' ability to provide a bespoke green energy service to customers that meet the customers' individual needs and desires other than the constraints imposed by the utilities' tariffs.
- Noble: Has a "soup to nuts" renewable product offering that depends on the customers' needs and goals. It is customized to each and every customer and can be as simple as supplying unbundled RECs or as complicated as a three way, long term contract that enables source to sink renewable energy deliveries.

c) **Are there new or additional ESS offerings that regulated utilities can enable through direct access that will meet the requirements of direct access laws and improve customer access to the kinds of "green energy" products that they are seeking?**

- Iberdrola: If "green energy" options via Direct Access are constrained, it is because the implementation rules. Examination of barriers to Direct Access is warranted (without respect to specific products).
- Renewable NW: Yes, likely ways to improve direct access to improve access to renewable energy. Recommend Commission conduct a more comprehensive analysis of the current Direct Access structure as a vehicle for renewable energy supply and whether that structure could be improved to supply customers with renewable energy.
- Shell: On the Pac system, the Commission should approve the five year opt-out proposal advanced by Pac in Docket No. UE 267, subject to modifications proposed by the stipulating parties in the "stipulation" that was submitted in October 2013. Also, any caps on customer participation in direct access should be eliminated.
- NIPPC: Yes, utilities could file revised tariff sheets to allow for a VRET direct access product that allows for more flexibility in purchasing green energy products, including allowing additional selection windows, reduced terms for transition charges, lower caps on usage, and confirmation that load not previously included within a utilities' service territory (such as industrial operations relocating from out of state) are not subject to transition charges.
- ICNU: New ESS offerings, potentially combined with additional or refined direct access tariffs are the best option for a successful VRET and would be fully consistent with HB 4126.
- Noble: The primary incentive that the utilities can offer to promote use of additional green energy above any beyond the RPS would be to life the program restrictions that currently exist to limit direct access service for those customers who wish to purchase a green energy product from source to sink. This would include elimination of direct access enrollment windows, participation caps, and minimum usage limits.

II. Whether Further Development of Significant Renewable Energy Resources is Promoted? *(issues related to HB 4126 Section 3(3)(a))*

1. **Should VRET renewable resources be defined to include the same types of renewable energy resources as the Renewable Portfolio Standard (RPS) (e.g. solar power, wind power, only certain types of hydroelectric power)? Should "further development of significant renewable energy resources" include buying the direct output and/or bundled Renewable Energy Certificates (RECs) from a *new* renewable resource power plant? From an *existing* plant? How should "new" and "existing" plants be defined? Should there be a limit on how old the plant is? (e.g. recently constructed or constructed since a selected year)?**

- Iberdrola: Should parallel RPS qualifying resource, except project vintage (age). VRET should incent new development. VRET eligible resource should include: resource not yet under construction, not planned to serve utilities' native load, or not having yet served Oregon utilities' native load. Bundled/Unbundled requirements should reflect RPS law. May need flexibility to address any minimum renewable energy requirements and full/partial loads.
- Renewable NW: Support VRET only if it supports new renewable resources built specifically for the VRET product because underlying policy reason for VRET is to promote new demand for renewable energy. VRET should serve customers with primarily RPS-eligible renewable energy. If existing projects are used at all, it should follow the Green-e requirements (currently requires that generation unit and purchaser have signed contract within 6 months of generation unit's commercial online date).
- PGE: RPS and date used in describing qualifying electricity are reasonable guidelines. No need for Green-E style limitation or other qualification complications. The term "new" was considered and discarded in developing the bill's language. Using an existing resource in a VRET would eliminate that project from use in compliance with RPS and would require utilities to acquire additional new resources, which further develops renewables.

- **Pac:** Adopt a broad definition of VRET resources that is not limited by definition of renewable resources under the RPS. If legislature wanted VRET choices to be limited to RPS eligible resources, they would have said so. VRET is a customer driven utility offering that should be responsive to needs of individual customers. Customers electing VRET may seek generation profile that has zero carbon emissions, and non-RPS hydro may be OK for such a customer. A utility or another entity would be precluded from including this type of resource in the VRET if limited to only RPS-eligible resources. Considering customer-driven nature of VRET, questions of "additionality" or whether output or RECs should be purchased from new as opposed to existing resources should not prematurely limit VRET offering to one or another. Many customers' corporate objectives recognize "additionality" as a desirable feature for participation, so VRET may need to incorporate some level of additional resources to respond to customer needs.
- **Shell**: If a VRET adopted, the scope and scale of eligible renewable resources should be broad. Expanding types of renewable resources in the VRET would "promote the further development of significant renewable energy resources." Increased customer participation in enhanced renewable procurement will promote renewable energy project development. Limitations on types of renewable resources included in the program will discourage customer participation as well as supplier participation.
- **WRI**: Variety of approaches exist. Nevada has only allowed renewable resources defined by their RPS rules. North Carolina has defined a vintage year of 2007 as the definition of new. Customers want additionality, regional proximity, and REC credibility. Setting constraints on utilities seems unnecessary if customers can choose between generation options offered by utilities and others.
- **Center for Resource Solutions (CRS)**: Use resources that are eligible for Green-e certification, which are determined through stakeholder comment periods and independent governance board to be the type of resources customers believe are renewable and further sustainability goals. They are consistent with Green Power Partnership and corporate renewable energy use recognition programs at US EPA. Green-e will only consider these resources eligible for inclusion in a Green-e Energy certified product, and so it must meet the Green-e Energy National Standard. Also, Green-e requires that electricity generation occur within a specified period of time in relation to sale of electricity or RECs to the customer. The current Oregon RPS REC banking rules are less strict than the Green-e vintage requirements for certified products. Green-e requires renewable energy sold in certified products come from facilities no older than 15 years and allows the use of renewable energy beyond the 15 year limit if the purchaser made a long term (greater than 15 years) commitment to purchase RECs or renewable electricity from the generator close in time to the commercial online date.
- **NIPPC**: Yes, same types of resources as RPS. Any renewable resources not constructed and/or operating to serve the utilities' native cost of service load should qualify as a renewable resource for any VRET, regardless of the online-date of such resource.
- **ICNU**: REC based VRET would be governed by existing REC standards and should responsive to customer needs. If a customer and power purchaser wish to enter into a PPA from a renewable generation that is not REC based, the content should be determined by the customer and the ESS.
- **Noble:** Yes, VRET resources should meet RPS standard. New should be a date that reasonably reaches back in time without incorporating resources that have been online for more than five years.

2. **In order to be considered "further development of significant renewable energy resources," should there be geographic limits on the source of eligible renewable energy (e.g. Oregon or the Northwest)?**

- **Iberdrola:** Should reflect RPS requirements.
- **Renewable NW**: Customers should have access to the most competitively priced renewable energy resources and those that support their resource preferences. Some customers will prefer resources closer to their load. Nothing in HB 4126 specifies a particular state or region.

- **PGE**: Geographic limits are unnecessary and would likely increase costs. Location of resource and proximity to ancillary services helps with cost, which is more important than artificial geographic limitations. If geographic limitation is sought, then use RPS limitation of projects located within the WECC and for which electricity is delivered to BPA, utility's transmission system, or a point for subsequent delivery to utility offering VRET.
- **Pac:** Primary consideration is customer need. If renewable resource meets customer need, then location of resource should not be prescriptive. If legislature intended to geographically limit location of renewable resources, it would have said so in the bill.
- **Shell**: No.
- **WRI**: Utah and others have geographic bounds on offerings, through others have not. There are not large price differentials in renewable resources between states in the NW – as there in regions bordering Midwest – so flexibility of choices should be given priority over further constraints in order to maximize further development of resources.
- **Center for Resource Solutions (CRS)**: VRET customers should receive a minimum percentage of renewable equivalent to the RPS requirements and tariff should allow customers to purchase more renewable energy than would otherwise be provided through the RPS. Green-e does not have a minimum purchase size for non-residential customers. For certified green pricing programs, Green-e requires that the voluntary purchase be additional to any renewable energy delivered as a result of the RPS (i.e. customers should not be charged extra for RPS renewables that they should receive anyway).
- **NIPPC**: All renewable resources within the Pacific Northwest region should be eligible. The PNW electricity market is integrated and the benefits of low carbon electricity generation benefit Oregon directly even if power is generated in Washington or elsewhere in the PNW.
- **ICNU**: No such restrictions are in HB 4126.
- **Noble:** Assuming source to sink offering, there is no need for a geographic limit because only resources whose output can actually reach Oregon loads would qualify.
- **ODOE:** Resource eligibility does not need to be decided in order to study VRET models. However the RPS, as a mandatory program, is meant to set a regulatory floor. In terms of resource eligibility requirements, the VRET should not be less restrictive than the RPS. The Commission should not create or evaluate a new resource eligibility standard here, although there must be some framework. The greatest driver for resource content should ultimately be customer interest. The VRET, as a voluntary option, will need to entice customers to subscribe. As learned from current voluntary programs, customers are more interested in supporting local projects with a community story. Under current voluntary programs, customers prefer wind and solar resources. Any framework for VRET eligible resources should be designed with customer interests at the core. VRET should be 100 percent renewable energy product, rather than an arbitrary percentage. Customer message should be simple. If it is found that a VRET product cannot be crafted at a cost that will satisfy customers, then there can be further consideration of a partial product at a later time.

3. Given that the RPS is a minimum threshold for utilities in the existing cost-of-service rate based system, what should be the minimum renewable energy required in a VRET product (not including non-renewable resources that may be needed for back-up/supplemental service or firming/shaping)?

- **Iberdrola:** If a customer has a partial load requirement option under a VRET, then the requirement should be the difference between existing service (RPS threshold in a given year) and 100% of the load to be served under VRET. Because of variable RE generation, VRET should allow share of energy over a period of time (e.g. annual basis) to be non-RE firming/shaping services. Combination of real-time RE deliveries, non-RE firming/shaping services (with RECs), and limited overall use of unbundled RECs may balance grid reliability, strong RE product, and new resource development concerns. Overall, there should be a material minimum threshold (e.g. 60% of load served by RE that combined RPS and VRET) to enable customers to make desired green "claim" and this claim should be transparent to the public by reflecting the renewables percentage actually being procured. This information should also be disclosed in the utilities' required fuel-mix report.

- Renewable NW: VRET should only supply renewable resources. Customers should have flexibility, but minimum must be more than the proportion served by the utility's RPS requirement. VRET should clearly be an above and beyond option.
- PGE: VRET should offer customers opportunity to reach 100% or more green.
- Pac: Any Pac VRET offering will be designed in response to customer needs, which may include 100% renewable resources. To ensure that VRET offerings are responsive to customer needs, Commission should not establish minimum threshold requirement at this time.
- Shell: Under a Model 1.b/x type VRET, the customer remains a bundled [cost of service] sales customer of the utility. The customer's arrangement for renewable energy delivered by a third party must be for incremental renewable energy beyond the amount of renewable energy reflected in the utility's portfolio.
- NIPPC: Minimum renewable energy threshold for a VRET product, excluding ancillary services, should be significantly above the RPS minimum threshold, and could be 100%. To the extent a customer desires service that does not meet whatever threshold is ultimately established, they would still be able to purchase a mix of power including renewable power pursuant to direct access.
- Noble: If adopted, VRET should apply only for a product that is 100% RPS compliant excluding firming/shaping.

4. **Of *all the models* in the *VRET Models Table*, which model is most likely to promote "further development of significant renewable energy resources"?**

- Iberdrola: Model 1.c/d (but dependent on VRET terms/conditions) and Model 1.a holds promise.
- Renewable NW: Commission should adopt parameters, not particular model, to ensure VRET supply is incremental to renewable energy policies and that new supply to promote renewables expansion in the region.
- PGE: best promoted through meeting of customer and system demand, which depends on price and resource features. The more variety tested through process, the more information available to weigh results.
- Pac: All models have potential to promote, but this is not the critical question. The critical question is whther the models are structured in a way that makes them attractive to customers. Customer response will determine need for additional renewable resources and therefore maintaining flexibility for utility to respond to customer needs is the paramount issue.
- Shell: Robust direct access market without unnecessary barriers and limitations would be the best means. If a VRET is adopted, then Model 1.b/s type of VRET is most likely to promote it because it allows greatest flexibility between the renewable energy supplier and the customer, thus encouraging participation.
- WRI: Keys to success in other jurisdictions are starting to emerge. Emphasizing ease of use, low transaction costs, and maximizing customer choice are reported to be crucial to getting transactions completed.
- NIPPC: A direct access VRET, because it will allow ESS and IPP entities to do what they do best – provide creative solutions and take market risk to bring new energy solutions to Oregon. In contrast, models where the utility is a middleman will dis-incent participation of IPPs and reduce the overall amount of renewable energy developed. Although NIPPC supports customer owned generation, VRET model relying solely on customer owned generation would not be successful because it would artificially constrain the potential sites and size of developments and not lead to development of significant renewable resources above that allowed under the existing framework. Utility owned models will constrain competition and severely dis-incent any further IPP development in the PNW, reducing the overall amount of renewable resources developed.
- ICNU: No VRET will promote development of renewable resources unless it is elected by a customer to meet its electric needs. Customers in workshops have expressed a desire to work with utility partners to access open renewables markets, as they are able to in other jurisdictions. Such cooperation by utilities would be responsible to customer needs and facilitate the desires of many non-residential customers to access green energy, and as a result would more effectively promote renewables development.

- **CUB**: Both the direct access and the "utility as a facilitator" type approaches help pursue the path of development of significant new renewable resources. The approach involving a third party owned resource/utility assisted transaction would appear to provide more opportunity to develop more renewable resources than other approaches. It provides a role for independent power producers to develop projects and sell the output and does not depend on the ability of one company (the utility) to build those resources.

III. What may be the Effect on Development of a Competitive Retail Market? *(HB 4126 Section 3(3)(b))*

- **Renewable NW**: Understands this section to examine the effect of VRET on direct access specifically, and more generally, on Oregon non-residential energy customers' ability to choose their energy supply from among a diverse range of competitive providers. In general, a b/x type model (connections between customers and renewable energy developers) should positively impact development of a competitive retail market because it encourages customers think about different supply choices. A c/d type model (aggregated supply offered by utility) is less supportive of development of a competitive retail market, but, in theory does not impact the same customer profile.
- **WRI**: As discussed in 07/25/2014 comments, consider whether and the extent to which implementation of a VRET would increase the incentives or ability of a utility to behave anti-competitively, in comparison to the case in which no VRET could be offered. Would the VRET make uncompetitive outcomes more likely when compared with the "no VRET" case? Keeping this principle in mind can avoid impacts on the competitive market. If there are flaws in current regulation applicable to retail competition, these flaws should be addressed separately in proceedings relating to the over competitive retail market, including the renewable energy segment of that market. They need not delay or preclude the environmental and other public benefits to be derived from VRETs.
- **CUB:** Improving direct access and assisting the utility in facilitating customers with either third party or self build projects by definition ensures that a competitive market is maintained or enhanced.

1. How should a VRET's effect on competitive suppliers and the direct access market be assessed?

- **Iberdrola:** Since there is a lack of empirical information, must rely on logic. Consider that the competitive retail market is already limited by (a) program cap in regulation and (b) significant transition charges and (c) other impediments. A new tariff to increase opportunities for incumbent utilities to serve commercial and industrial customers (for which direct access is an option) can only serve to limit further development of a competitive retail market.
- **Renewable NW**: VRET goal should be a path to renewable energy for customers who are unwilling or unable to use direct access. There should be clear differences between and advantages/disadvantages of direct access and VRET paths. The design should not favor VRET where a level playing field can be achieved. Making the VRET very clearly an incremental renewable energy supply option may help to distinguish it from direct access, so that customers looking primarily for undifferentiated cost savings and a blend of renewables and market purchases can remain primary candidates for direct access.
- **PGE**: Depends on model design. Example- Utility owned model would operate in regulated environment.
- **Pac**: VRET is intended to increase market for renewable energy, smaller segment of energy market in the state. In contrast, the competitive retail market that the direct access law was designed to facilitate is a broader construct which makes comparisons between the two difficult and potentially non-informative. VRET should be viewed as complementary to the competitive market – whether the larger competitive market or the competitive market for renewable resources – and being able to provide greater flexibility for customer options. HB 4126 was pass to allow utilities to provide these additional options to customers that are not currently being met. Key focus for assessing a VRET should remain on the customer and whether the option is meeting customer needs without adversely impacting other customers. To the extent the utility is in the same competitive market for the acquisition of renewable resources as an ESS, a utility-offered VRET should enhance the competitive markets and opportunities for customers and the state. VRET is a voluntary offering and, as such, will only be

successful if it is competitive with current offerings. This inherent incentive to make VRET offerings competitive helps ensure that competitive market for these types of renewable products will develop.

- Shell: VRET that allows utility to sell renewable energy from a portfolio of renewable supplies that is separate from the utility's bundled sales portfolio presents a new competitive utility supply offering that constitutes "direct access." This would inhibit competition in the retail market. Under models 2, 2.c/d, and 5.b, the utility would offer its new renewable supply portfolio as an alternative to "default" bundled cost-of-service sales service, which puts the utility in competition with its own bundled sales service and direct access. VRET that allows utility to compile its own separate portfolio of renewables and sell to targeted group of customers would be inconsistent with utility's role as the "default" supplier of electric commodity service to retail customers. Utilities should not be permitted to leverage their monopoly status to offer a new competitive procurement service option. If the electric utilities are allowed through a VRET to offer a competing renewable supply option, the utilities will enjoy a multitude of competitive advantages that come with their monopoly status – access to customer lists, access to individual customer load data, name recognition and purchasing power in the energy commodity and renewable energy market, preferential access to transmission and ancillary services, and the ability to subsidize their renewable supply options through the use of existing assets, existing supply and transmission relationships, and existing utility resources including personnel. These aspects of utility status confer an inherent and unjust competitive advantage.
- WRI: Central measure should be do competitive suppliers have the same or more opportunity to sell power to customers than they do under current rules today, imperfect through some parities clearly find them.
- NIPPC: target market for competitive suppliers is any commercial or industrial load that does not want to be served through a regulated cost of service and/or desires a specific power mix unavailable from the utility's standard. Any VRET service provided by the utility has a per-set detrimental effect on the competitive retail market.
- Noble: Any VRET program should be designed to ensure that access to the program and the treatment of transition adjustments is non-discriminatory between the VRET and direct access.

2. **Is the competitive retail market harmed if a regulated utility is able to make offerings under a VRET to non-residential customers that a third party competitive supplier is not permitted to provide under the terms of current direct access tariffs (e.g. enrollment windows and transition adjustments)? If so, how?**

- Iberdrola: Yes, the retail market is harmed by providing customers alternative products through the utilities that ESSs are not able to provide under direct access. Limited enrollment windows, transition charges, and other impediments make direct access very difficult. A VRET without those limitations would further hamstring ESSs in a discriminatory fashion.
- Renewable NW: Not necessarily, there can be a level playing field with room for well-supported differences.
- PGE: No, under PGE's proposed models, VRET is under cost of service.
- Pac: No, VRET should be designed to provide additional opportunities for customers.
- Shell: Yes. Utility has built-in competitive advantages interacting with existing customers. If a utility has the ability to compete with ESSs to offer a product/service without limitations that apply to ESSs, then the utility advantages is reinforced.
- WRI: If the competitive supplier can fairly compete to provide the generation resource under the VRET, they have experienced an increase in their potential market by the utility being able to offer renewable energy under the VRET rather than a limitation of their market.
- YAM Services: IF there is any transition mechanism employed to recover stranded cost, the model should be developed so that it is neutral and not by unintended consequence create a barrier to entry in the VRET market.
- NIPPC: Competitive retail market would be dramatically harmed to the extent utilities could offer service under terms not available to the retail market.

- **ICNU**: Yes, the competitive market would be harmed because the incumbent utility would have product options not available to competitive suppliers.
- **Noble:** Yes. The underlying rationale for enrollment windows and transition adjustments does not change just because the program is utility-sponsored VRET rather than direct access. If direct access customers are subject to enrollment windows and transition adjustments but VRET customers are not, then the utility would be in a position to create an unlevel competitive offering. If direct access customers have to operate within a predefined arrangement that protects the remaining bundled customers and/or shareholders, then allowing the utility to bypass these protections in their VRET offering is unduly discriminatory and harms the competitive retail market.

3. **With respect to *Model 1(b/x) [third party owned resource & regulated utility facilitated]* and *Model 1 (c/d) [third party owned resource with aggregation]*:**

- **Renewable NW**: 1(b/x) and 1(c/d) are quite different in terms of utility roles, so expect to have different implications for the competitive retail market.
- **CUB**: The approach involving a third party owned resource/utility assisted transaction could be tailored according to a customer's need and offerings of various third parties. The utility role is relatively clear and it should be easier to wall transactions from base service in order to isolate costs to prevent cost shifting to non-participants.

   a) **What are the effects, if any, on the competitive retail market if Independent Power Producers (IPPs) supply power through the regulated utility as part of VRET design in these models?**

- **Iberdrola:** Competitive retail market is harmed by providing customers alternative products through the utilities that ESSs are not able to provide under Direct Access.
- **Renewable NW**: This approach maintains competition because it allows non-utility market participants to develop, own, and operate projects. In regards to direct access – VRET can be complementary and offer customers who are unlikely to move to direct access an opportunity to access independent renewable energy supply through a less comprehensive alternative retail supply model. VRET could increase demand for new renewable energy supply that would otherwise go unfulfilled, rather being seen as reducing demand for renewable energy supply through direct access.
- **PGE**: IPPs currently supply renewable power to PGE would likely continue to do so, if VRET made available.
- **Pac**: Market should be indifferent to who owns the generation as the utility and the IPP are likely to incur the same resource costs.
- **Shell**: VRET structure in 1.b/x is different from 1.c/d because of the utility's role. Under 1.b/x with utility as a middleman between the supplier and the customer, retail competition is substantially preserved because suppliers compete with one another to supply power to individual customers. By contrast, under 1.c/d, the utility acquires customers through its marketing efforts and the utility acquires the renewable supply from third party suppliers. Under this approach, the utility obtains a separate supply portfolio to sell to the targeted customers. This provides the utility with a competitive advantage, and creates the potential for cost-shifting from participating to non-participating customers.
- **NIPPC**: Allowing the regulated utility to act as a middle man would damage the retail market in two major ways. First it would provide the utility with access to extremely sensitive competitive market information that would give the utilities an unfair advantage. Second it compromises the relationship between the ESS/IPP and its customer. By contrast, there is little, if any, advantage to this model.
- **ICNU**: Retail markets may become more competitive if IPPs supply power through the regulated utility, but much about this model is uncertain.
- **Noble:** This model, given certain adaptation, is essentially a whole sale buy through tariff, where the utility supplies energy provided to the utility by the customer's chosen whole sale supplier and the utility also provides imbalance energy. This is a model that is adopted by jurisdictions that either do not want or legally cannoy allow

customers to bypass utility procurement. For example, Arizona Public Service's (APS) Experimental Rate Schedule AG-1. In states that have direct access, this is a suboptimal model as it limits the type of energy products to essentially wholesale products. This model is one potential form of retail wheeling.

b) What should the role of the regulated utility be in developing and offering a product or transacting between customers and an IPP under these VRET models?

- Iberdrola: Fairly described in Model 1 "relationships" column in table: "*Regulated Utility facilitates between a 3rd party and customer(s). *Customer and 3rd party negotiate for renewable energy service. *Regulated utility takes ownership of power through contract with Third Party. Tariff is set for same price and duration as contract. Contract terminates if customer defaults. *Utility remains primary point of contact for billing and (by customer choice) load management/ancillary services. Utility could credit customer bill for project output (at credit amount TBD - e.g. utility's wholesale avoided cost rather than retail rate) and service balance of customer's energy and capacity need (if any) at cost of service rate."
- Renewable NW: Utility roles are very different depending on model. In 1(b/x), utility facilitates a transaction for energy reached between customer and supplier/IPP, but continues to meet customer demand and maintains primary billing role. In 1(c/d) utility takes control of an aggregated product, promotes it to customers, and procures the renewable energy to supply it.
- PGE: Depends on model, for example, utility could purchase power from IPP on behalf of customers.
- Pac: Through current resource procurement, utility is already transacting with IPPs to serve customers. Under a VRET, utility may be in the same role to acquire least cost resources to serve a specific customer or group of customers.
- Shell: Under 1.b/x, the utility acts as a "sleeve" between the supplier and customer. The utility will pass along the energy and cost of energy from the supplier to the customer. The central commercial arrangement is between the renewable energy supplier and customer, similar to direct access. Although 1.b/x provides structure under which the utility will be competitively neutral, it is inferior to direct access.
- NIPPC: Regulated utility should have no role in developing or offering a product or transaction between customers and an IPP under these VRET models.
- ICNU: The regulated utility should be supportive of and assist in facilitating the offering of competitive products through any VRET model.
- Noble: The chief role is to be the customer's imbalance provider. A good example is the Arizona Public Service AG-1 rate schedule, which, despite shortcomings of this type of arrangement, is a well-designed wholesale buy through tariff. Excessive leaning on APS for imbalance service can lead to disqualification from the rate schedule.

c) Would these VRET models comport with the requirements of a filed tariff (e.g. must list prices and be accessible to all similarly situated customers [see HB 4126 Section 3(4) and ORS 757.205, 757.210, 757.212, 757.215])? Can these models be implemented such that an IPP is not required to provide confidential pricing data to a regulated utility (e.g. non-disclosure agreements)?

- Iberdrola: Tariff may face challenges in being broadly applicable, particularly if a green-energy provider has an agreement to serve a specific customer. Billing/accounting processes would need significant safeguards to maintain confidentiality when the utility or an affiliate may be a bidder and an IPP is a bidder. Cost information may be required to conduct competitive procurement, which could be a problem if more than one model is adopted and the utility could offer a better price through model 2.
- Renewable NW: Yes, tariff can clearly state all other charges while renewable energy supply price may vary from customer to customer. Example of where tariff does not state exact price is the competitive bidding portion of the solar VIR program. If necessary, statute allows for alternative forms of regulation plans, including resource rate plans (ORS 757.210-212). If utilities or their subsidiaries are allowed to compete to develop and own

renewable energy supply for VRET along with IPPs, then pricing confidentiality is very important. If transmission arrangements for direct supply contracts between the renewable energy project despite the utility continuing to provide some elements of service under cost of service rates, then customer-developer direct contracting is the cleanest way to handle confidentiality issues under the (b/x) type model. Otherwise, firewalls and independent third party assistance may be useful.

- PGE: Model could be implemented such that IPP is not required to disclose confidential pricing data to the utility, but VRET would be tariffed. Query whether PUC would then govern IPP's pricing, resource content, etc. since this is a regulated option.
- Pac: Yes, VRET models should comport with requirements of filed tariff, which may not list exact prices but instead list parameters for setting the ultimate rate. Regarding IPP providing confidential pricing data to the utility, the utility will need to know the price in order to bill the customer, nonetheless, Pac supports use of standards of conduct or non-disclosure agreements as an acceptable way to address confidentiality concerns, subject to necessary carve outs for disclosure required via regulatory reporting or proceedings.
- Shell: Model 1.b/x could be adjusted so that participating customers pay the cost-of-service sales price, and renewable energy suppliers are paid, by the utility, a fixed price in a contract. The difference in price between cost-of-service and a contract between the customer and the renewable supplier can be settled between them.
- NIPPC: No. This model cannot be implements such that an IPP is not required to provide confidential pricing data to the regulated utility.
- ICNU: VRET should be designed to comply with requirements of a fixed tariff. Similar pricing structures already exist with variable pricing terms. Example – PGE has market based pricing, which comports with fixed tariff requirements.
- Noble: In as much as the prices relate to the services offered by the utility, yes. For the services provided by the IPP, that is a contract between the IPP and the customer and should be confidential.

4. **With respect to *Model 1(c/d) [third party owned resource with aggregation]* and *Model 2(c/d) [regulated utility owned resource with aggregation]*, if aggregation is allowed, should a regulated utility be prohibited from acting as an aggregator such that the VRET would only permit aggregation by registered aggregators (see OAR 860-038-0380)?**

- Iberdrola: Yes.
- Renewable NW: No. Whole point of c/d type model is for the utility to play the role of aggregating customers who are not motivated to seek individual transaction in the market. Even for a b/x type model, customer should be able to use utility aggregate meter locations without utility using a separate aggregator.
- PGE: No, rule is intended to protect consumers and requires registration. Given PUC broad authority over utilities, utilities should neither be prohibited from acting as aggregators nor be required to register with PUC as an aggregator.
- Pac: Should evolve to meet customer demand, therefore flexibility in this model is important.
- Shell: Both of these models, if adopted, would inhibit competition in the retail market because the utility would solicit renewable energy supply to establish a separate portfolio, and the utility would solicit customers to purchase from this separate portfolio. The utility would be using its market power to compete against its own bundled cost of service and compete against direct access. The utility's role as a competing supplier offering a separate portfolio of renewable supplies to a targeted class of customers also raises cost-shifting issues.
- NIPPC: Yes, the regulated utility should be prevented from acting as an aggregator (unless through an affiliate). Otherwise the utility would be in a position to use its monopoly status to lock out competition to the detriment of the competitive retail market.
- ICNU: Aggregation should be performed consistently with the Commission's aggregation rules. HV 4126 was specifically designed to leave direct access rules intact.
  Noble: Yes, should be prohibited.

5. **With respect to *Model 2 [regulated utility owned resource]* and *Model 2(c/d) [regulated utility owned resource with aggregation]*, what are the effects, if any, on the competitive retail market if a regulated utility owns or operates resources as part of VRET design in these models?**

- Iberdrola: Competitive retail market is harmed by providing customers alternative products through the utilities that ESSs are not able to provide under Direct Access.
- Renewable NW: Utility ownership makes effect on competitive retail market more pronounced. Would require more robust protections against ownership bias. Not clear if there are similar concerns with utility operation.
- PGE: None, because VRET customers paying premium over Cost of Service, under PGE's proposed models. Utility as an additional supplier promotes growth in the market.
- Pac: No effect or the effect it a larger competitive retail market, which is consistent with HB 4126 goals.
- Shell: Both of these models, if adopted, would inhibit competition in the retail market. (see answer to #4).
- NIPPC: Model 2- regulated utility owned does not warrant further consideration because it does not pass the statutory hurdle of not harming the competitive retail market. Allowing a utility to offer such VRET services outside of a cost of service model will eliminate all retail market competition.
- ICNU: Requiring customers to purchase solely from a utility-owned resource will negatively impact the competitive market. Oregon utilities have declined to consider using a generation affiliate to own and offer renewable resources to customers as market competitors. And utility owned VRET resources would create a significant cost shift danger, if included in rate based and allocated to all customers.
- Noble: Any generation assets owned by the utility must be offered to all customers on a non-discriminatory basis. Otherwise, utility is abusing its monopoly status by offering one price to one set of similarly situated customers and another price to another set of the same similarly situated customers. This is unduly discriminatory pricing. And the competitive retail market would be seriously harmed if the Commission were to allow the utility owned renewable generation to be offered to customers as an alternative to standard "brown" cost of service offerings without making that renewable service subject to the same restrictions that apply to direct access offerings.
- CUB: The issue of utility-owned resources is fraught with problems. It seems unthinkable that a single customer or even a group of customers would be able to pay a utility for a project dedicated to their needs alone. For that amount of money, the customer may be better off building their own resource. This approach would muddy the waters in terms of the role of the utility. The utility to stick to managing an overall system to provide power to its service territory. Providing specialized products to particular customers begins to veer away from the core mission.

6. **With respect to *Model 4(a/X) [customer owned resource]:***

- ODOE: In the future, customers with specific renewable energy goals may increasingly choose to build and own new generating resources that meet their specific goals. Today the customer may build an off site resource and enter into a PPA with the utility as a QF and retain the unbundled REC generated by the resource. A VRET option could provide the customer a bundled REC from the customer's off site resource. If a customer owned resource is off stie, the operator of the resource (possibly the customer itself) should be treated as a third party supplier similar to an IPP role in Model 1(b/x). As an alternative to a VRET, the customer may also have the option (today) to contract with an ESS to acquire energy from the customer's off site resources and delivery that energy (bundled with RECs) back to the customer through direct access. If a customer owned resource is onsite, the customer may currently enter into either a net metering interconnection or a partial requirements tariff and receive both the energy and RECs generated by the resource – although depending on the time of generation relative to the time of use, some RECs may become unbundled. These existing options are likely to satisfy most customer's needs, but a VRET option could be made available as an alternative way to receive bundled RECs from a customer owned on-site resource. Such a VRET offering should be completely distinct from net metering.

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- **CUB**: Large customers have the resources and wherewithal for self-build. Existing policies or regulatory practices may interfere with the adoption of a customer owned VRET approach, which should be explored in order to identify solutions to the barriers in place. Also, this maybe another way that the utility needs to help a customer facilitate an outcome that is advantageous to the customer. If a customer wants to build a resource to serve its facility, it may need some help in terms of integration or managing output. Those tasks could be easily isolated to the customer(s) needing service to prevent cost shifting. This approach could be a subset of the third party resource discussion, except rather than contracting for resources, the customer is owning and operating the resources themselves. And rather than the utility facilitating the interaction between the customer and a third party provider, it is instead facilitating the customer's interaction with the system that the utility is charged with managing.

a) **What are the effects, if any, on the competitive retail market if a customer owns or operates resources as part of VRET design in this model?**

- **Iberdrola:** Customer owned or operated resources are a type of retail competitor.
- **Renewable Energy Markets Association**: Owners of on-site RE system (solar, small wind, etc) should be clearly informed as to the nature of their REC transactions and the effect that selling such RECs would have on their ability to claim GHG reductions or green power consumption for the facility/site/roof in question. This would reduce the potential for double counting of environmental attributes.
- **Renewable NW**: Customer should be treated as same as an IPP for VRET design. Presumably customer could own/operate on or off site resource as part of Direct Access without raising competition concerns.
- **PGE**: Customer as owner/operator helps market. Under PGE's existing tariff, customers own resources through net metering, PURPA contracts, and partial requirements service.
- **Pac**: No effect or the effect it a larger competitive retail market. Customers are currently not prevented from owning or operating renewable resource located behind the meter.
- **NIPPC**: Supports customer ownership and operation as currently allowed in regulation. However, allowing customers to own or operate resources beyond their own portfolio needs will have a detrimental impact on the competitive retail market by reducing prospective customer base available to market suppliers.
- **ICNU**: This model should be handled through existing options for customers.
- **Noble:** As long as customer ownership option is consistent with existing customer ownership structures and models, it should be competitively neutral.

b) **Can this model already occur through Partial Requirements tariffs (e.g. PGE schedules 75, 76R, 575 or PacificPower schedules 47, 247, 747)? If not, how is it differentiated from partial requirements service?**

- **Renewable NW**: Partial requirements tariffs seem to be designed for on-site non-variable customer generation. Unclear if it is available for variable generation. Cost structure would likely be different for variable generation.
- **PGE**: Yes, Schedule 75, for on-site self-generation. VRET model could support off-site resources that do not qualify for partial requirements service.
- **Pac**: Partial requirements service is available where customer has on-site generation that is behind the meter. A customer-owned resource under a VRET should be limited to off-site generation for which company's facilities would be required to theoretically deliver the power to the customer. Any resource behind the meter should be subject to applicable existing PUC approved tariffs.
- **NIPPC**: Yes.
- **ICNU**: This model should be handled through existing options for customers.

c) **Would this VRET model comport with the requirements of a filed tariff (e.g. must list a price and must be accessible to all similarly situated customers [see HB 4126 Section 3(4) and ORS 757.205, 757.210, 757.212, 757.215])?**

- Renewable NW: see III.3(c) [Yes, tariff can clearly state all other charges while renewable energy supply price may vary from customer to customer.
- PGE: It could, under a few circumstances, like net metering, partial requirements, or qualifying facilities under PURPA for off-site generation that pays utility's avoided cost rate for power produced (set and filed with PUC).
- Pac: Yes, tariff may not list exact prices but instead list parameters for setting the ultimate rate.
- Center for Resource Solutions (CRS): there are benefits to customer ownership. They promote uptake of distributed generation and provide access to local renewables. However there are potential claims issues if attributes are transferred to other end users. Some owners may contract away RECs without realizing the long term implications, which can result in a double claim of the RECs. The claim could take the form of advertising that they are using renewable energy or participation in a carbon foot print or LEED program. To avoid potential for double counting, clear language should be used by generator or system host, and should not be buried in a highly technical contract rather is should be simply explained to the generator so that there can be informed choices that recognize the benefit of keeping the REC if they wish to use the renewable energy.
- ICNU: This model should be handled through existing options for customers.

d) **If a customer owned renewable resource is off-site, should it be treated as a third party supplier (e.g. similar to the IPPs role in *Model 1(b/x) [third party owned resource & regulated utility facilitated]*? If not, why? May a customer that generates more power at an off-site resource than needed at a given time sell the excess power to other customers?**

- Iberdrola: A customer should at least have the ability to deploy a third party to sell excess power to other customers. But this issue needs more information and consideration by PUC.
- Renewable NW: Off-site customer owned resources and on-site customer owned resource (not qualifying for or using NEM or partial requirements tariffs etc) should be treated the same as IPP owned resources.
- PGE: Could be treated as a third party supplier and sell to utility at avoided cost. Or an off-site, customer owned resource could be credited at the avoided cost or market rate on customer's cost of service bill for power produced.
- Pac: Should be limited to off-site generation for which Company's facilities would be required to theoretically deliver power to customer. Customer generator should be treated as a third party supplier. Could adopt standards of conduct to ensure that equal standards and treatment between third party suppliers and VRET customer generators. If VRET customer generator generates more power at an offsite resource than needed at the time, excess power can be sold to a utility as QF under PURPA. Otherwise VRET customer generator cannot sell excess power to other customers since they do not qualify as a utility.
- NIPPC: A customer that generates more power than it consumes should be required to act as an aggregator pursuant to section 860-038-0380.
- ICNU: This model should be handled through existing options for customers.
- Noble: If the customer needs the utility's distribution system, even in an over the fence arrangement, this would be model 1(b/x). A customer can always sell its excess generation if it registers as an ESS and serves "other" customers under direct access.

e) **Should on-site resources be limited to the Net Metering program? Does inclusion as a net metered resource depend on if any excess energy generation is anticipated? If a customer owned resource is on-site, but is permitted to be operated and managed by the regulated utility**

or IPP as a service provided through a VRET, should it be distinguished from the Net Metering program?

- **Renewable NW**: If customer's on-site resource qualifies for NEM, they may continue to use NEM. If the resource doesn't qualify for NEM (e.g. greater than 2 MW), then the resource should be part of customer's VRET supply.
- **PGE:** If net metered, then those OARs should apply. Or if net metering rules are otherwise met (customer owned, used to offset house load, etc), then it should not be distinguished from net metering program. If a resource is net metered and sized at no more than 90% of anticipated load, there is room for VRET service to provide protection to the customer on production risk and to "Backfill" to meet 100% green energy.
- **Pac**: Premature to determine interaction between net metering and VRET offerings because net metering is an established program that is separate from what could be contemplated in a VRET. Pac views VRET as applicable to resources beyond not behind the meter.
- **ICNU**: This model should be handled through existing options for customers.
- **Noble:** net metering is probably the easiest way to incorporate this model into the utility paradigm. The utility should pay the customer for any energy generated in excess of the customer's load at the utility's avoided costs, consistent with avoided cost tariffs.

IV. What may be the Direct or Indirect Impacts on Non-Participating Customers *(issues related to HB 4126 Section 3(3)(c))*

- **WRI**: Setting a cap for VRET subscriptions by utility that allows for measured growth and is tied to any identified need for new capacity or reduced market purchases would mitigate some of this concern. The identification and calculation of such costs can be undertaken in individual tariff proceedings.
- **CUB:** Direct access already protects against impacts on non-participating customers. In addition, a "utility as a facilitator" model could be developed that would also confine the costs of that facilitation to the customers that need it. Isolating those costs will be helpful in rate cases and other proceedings in identifying which costs are rate-based and which need to be assigned to a particular customer (or set of customers) due to the renewable facilitation service.

1. What regulatory tools or VRET design elements (e.g. transition charges for customers that leave the cost-of-service system) would ensure that the prices paid for products under a VRET reflect all costs associated with providing that service, including any requisite back-up/supplementary service (e.g. firming/shaping), without subsidization from non-participating customers?

- **Iberdrola:** VRET should be equivalent to Direct Access on these matters.
- **Renewable NW**: Depends on VRET model. In general, all models would consider: (1) paying for system resource not used any more (but were planned for/may be used in the future), (2) paying for system resources still being used by VRET customers, and (3) paying for intra-hour balancing services for variable RE. VRET model differs from Direct Access because VRET customers may not be "leaving" the system in such a comprehensive manner. Key question of how to address capacity already acquired to serve VRET customers, until that cost can be absorbed by other system load needs or plan for customer's possible return to the system. VRET rate design should balance administrative feasibility and acknowledgement of VRET resource's energy value and system capacity contribution, while capturing costs of system elements still being used. Rate design would need to address ancillary services and incremental intrahour flexibility required to balance VRET resource. Potential starting point is credit for energy cost, but leaving VRET customer's demand charge in place with discount for VRET resource's capacity contribution.
- **PGE**: With PGE's proposed models, VRET customers would continue to pay cost of service, so they contribute to the utility's fixed generation costs. With this, the customers are not "leaving its cost of service system." The

utility's fleet of generation resources would be used to provide ancillary services necessary for VRET intermittent resources (cost shift??). The costs of designing and administering VRET models would be separately accounted for and included in charges to participating customers.

- **Pac**: Transition adjustments and partial requirements tariffs currently exist as potential models. At the time of filing a VRET, requesting utility should address how non-participants are not unduly subsidizing participating customers.
- **Shell**: Under direct access, cost shifting has been addressed through the transition adjustment incorporated into direct access customer rates. Instead of trying to address VRET cost-shifting, Commission should focus on enhancement, extension, and expansion of direct access as the appropriate framework within which to "promote further development of significant renewable energy resources." Under a VRET, the potential for cost shifting arises in the following areas: (1) costs associated with utility's promotion of VRET using existing utility resources and assets that are paid for by all utility customers, (2) costs of administration of a VRET program, including procurement of resources for separate supply portfolio, billing customers for purchases from separate portfolio, educating customers, and fielding calls from customers (customer support function), (3) assignment of cost of incremental renewable resources that are unsubscribed/stranded as a result of participating customers returning to cost-of-service, (4) stranded capacity costs associated with "departing load" (customers electing VRET), (5) cost of flexible resources needed for integration of incremental renewable procurement. Cost shifting would be greatest under a VRET that allows the utility to establish a separate supply portfolio that the utility markets to customers. Under such a structure (Model 2, Model 5), the Commission would need to establish cost allocation protocols to ensure that participating customers or utility stakeholders bear 100% of the incremental cost and allocated portion of the embedded cost of any utility resource used to provide this service. Also, Commission would have to establish mechanism to ensure that customers that switch from cost of service to VRET bear the stranded costs, if any, associated with the reduction in the utility's obligation to purchase energy and capacity for cost of service customers.
- **NIPPC**: Direct access VRET already contemplates this risk and provides for transition charges.
- **ICNU**: The existing direct access rules should act as a starting point for VRET design elements to prevent cost shifting. Additional elements (firming/shaping) may be necessary, but depend on ultimate VRET design. As a starting point, Oregon's Incremental Cost of Compliance calculations should serve as a reference for firming and shaping costs.
- **Noble:** Direct access has addressed all these questions with transition adjustments and restrictions on utility participation as the generation supplier, among other protections. Commission should refer to the direct access program for guidance.

2. **What regulatory tools or VRET design elements would ensure that non-participating customers do not face increased risk of VRET obligations (e.g. costs of under-subscribed VRET resources or unfulfilled power purchase agreement obligations)?**

- **Renewable NW**: Expect customers to make 10-15 year commitments. In b/x type model, contract and tariff terms can be designed to allow customers and developers to negotiate around the risk of default, without material impact to the utility. In c/d type model, there is more utility involvement but risk can be minimized (e.g. PG&E example where customers subscribe based on cost of the utility's last RPS acquisition). Also, risk can be minimized with an aggregated pool of customers. In any case, risk can be quantified as the incremental cost of any capacity that goes unsubscribed, relative to the cost of meeting cost-of-service RPS obligations through another resource strategy – likely to be relatively small cost difference (or perhaps cost savings).
- **PGE**: PUC authority and stakeholder involvement provide safeguards against subsidy by non-participating customers. A risk premium or exit fee could be built into VRET design to safeguard against unfulfilled obligations. In the first PGE proposed model, PGE would aggregate customer subscribers so that a new renewable resource is built (by PGE or a third party) and owned by PGE. To avoid cross subsidization and minimize company/shareholder risk of under subscription, the model provides that PGE would rate base the resource at

null power (with rate of return), for the benefit of all customers, and the amount over and above the null power cost would be paid by the subscribers who would then "claim" the environmental attributes of the resource.

- Pac: Transition adjustments and partial requirements tariffs currently exist as potential models. At the time of filing a VRET, requesting utility should address how non-participants are not unduly subsidizing participating customers.
- Shell: See answer to question IV.1. Focus on direct access. If using VRET, consider the many areas for potential for cost shift (5 examples provided). Commission would need to establish cost-allocation protocols so VRET customers and utility stakeholders bear 100% of incremental cost and allocated portion of embedded cost of any utility resource used for VRET. Also would need to establish mechanism to ensure VRET customers bear stranded costs of reduction of utility obligation to purchase energy and capacity for cost-of-service customers.
- WRI: Different models have different remedies. Most to date have put risk on customers and cancel any obligation for the utility with the generator if the customer defaults. At least two proposed that the utility take the merchant risk on whether they will be able to sell the power and one assumes extra costs, if the power cannot be sold for anything but the PURPA rate, will be borne by their unbundled REC green power buying program. The Commission and utilities could consider these and other options to allocate risk.
- NIPPC: Under the direct access VRET model, these risks are borne by the ESS' and not by the utility or its customers.
- ICNU: Under no circumstances may non-participating customers bear the risk of unfulfilled VRET obligations. If utilities do not wish to offer VRETs through a direct access model, the utility must bear all cost-shifting risks associated with offering the VRET.
- Noble: This is the fundamental issue with utility procurement that is not part of the bundled service offering. In order to shift this risk from the utility, the shareholder, or the non-participant, this risk is carried in the direct access program by the participating customer, the ESS, or the IPP. A similar arrangement should apply in the VRET program for all the same reasons.

3. **How should the fixed costs of the existing cost-of-service rate based system be allocated to VRET participants that completely or partially leave the cost-of-service rate based system? 3**

- Iberdrola: Transition charges for VRET load should be imposed like those for Direct Access service, regardless of the share of load served under the VRET. While Direct Access policies need review, but to keep a level playing field between VRET service and ESS obligations, costs assumed with leaving the traditional regulated service should be consistent.
- Renewable NW: See IV.1 (not necessarily leaving the system like direct access). Participating customers could replace their energy charge with supply from renewable energy projects, while still paying a significant portion of their demand charge.
- PGE: With PGE's proposed models, VRET customers do not leave the cost of service and continue to contribute to the fixed generation costs of resources that the utility puts in service for customer loads.
- Pac: Anticipates that VRET participants will continue to be subject to the fixed costs for delivery service, consistent with delivery service costs for non-participating customers. For fixed costs related to transmission and generation service, VRET customers should continue to be subject to an allocation of those costs for some period of time for any load that is completely or partially serviced under a VRET. The period of time for which the VRET customers would likely be subject to fixed costs will depend on specifics and should be addressed when the utility files a VRET at the PUC.
- Shell: In same manner that direct access customers bear transition adjustment to prevent cost-shifting, VRET customers should bear a charge that reflects above market cost of resources that are stranded as a result of the customer's departure from bundled sales service.
- NIPPC: VRET participants with load not expressly contemplated in a utilities' IRP should not be subject to transition charges. VRET participants for existing load should not be subject to any transition charges to the

extent a utility is experiencing load growth elsewhere on its system (including other states and/or the ability to wheel to other markets) that absorb the decline in load from the VRET.

- ICNU: Transition charges must be designed to recover all stranded costs. Absent a direct access model, customers on a VRET should be treated separately from the cost of service rate model, while a method for assigning the firming and shaping services embedded in the cost of service should be established.
- Noble: Fixed costs of utility service stranded by departing VRET customers should be treated in the same manner as it prescribed in direct access.

4. **Assuming that VRET load is part of "total retail electric sales," what would be the impact to RPS resource cost recovery and compliance requirements if a significant amount of VRET load leaves the cost-of-service rate-based system? Would VRET customers continue to pay for RPS compliance requirements (e.g. their share of rate-based RPS renewable resources and RAC filings)?**

- Iberdrola: Assumes that utility provision of RPS resources is not affected and VRET service is offered to fill some or all the gap between RPS energy in traditional regulated service and full "green energy" requirements.
- Renewable NW: If VRET design involved customers leaving the cost of service system like direct access, then they may not be part of "total retail sales." But VRET customers are likely to have an ongoing connection to the cost-of-service system and would be part of total retail sales. VRET customers could continue to receive supply from and participate in paying for utility RPS procurement, depending on the customer's green claim requirements.
- PGE: To avoid cost shifting to non-participants, VRET customers should continue to pay for RPS compliance.
- Pac: See I.2 and IV.3 answers. To the extent the VRET load is part of total retail electric sales for purposes of determining compliance with RPS, then VRET customers should continue to pay for RPS compliance costs to minimize adverse impacts on non-participating customers.
- WRI: VRET customers should continue to pay for RPS compliance because as a utility offered product these customers would take credits for the RPS RECs retired on their behalf of their use of the system. This approach complies with guidance for greenhouse gas accounting and green claims as currently understood.
- ICNU: HB 4126 prohibits cost shifting. VRET customers should continue to pay for RPS compliance requirements.
- Noble: If the bundled portfolio RPS costs are stranded, and that depends on how the VRET plans to "count" VRET RPS sales, then customers should be required to pay for the portion of RPS compliance in the bundled portfolio that is stranded due to VRET participation just as they would be required to pay for those standed costs under a direct access program.
- ODOE: For VRET customers, RPS compliance requirements and resource cost recovery should follow the methodology current used for the other voluntary programs where the costs of RPS compliance are included in the tariff. Under ORS 469A.052, RPS compliance requirements are calculated as a function of the utility's retail load meaning no resources are exempt from inclusion in the RPS compliance obligation. These compliance requirements mimics the current requirements placed on ESSs. The VRET should reflect these standards.

5. **With respect to *Model 2 [regulated utility owned resource]* and *Model 2(c/d) [regulated utility owned resource with aggregation]*, should the regulated utility have a separate set of resources used for VRET customers in a "VRET rate base" for which the costs and rate of return are regulated by the PUC? How should the regulated utility account for separate capital investments and costs of capital related to a VRET?**

- Iberdrola: Yes, VRET resources should be isolated from the utility's supply portfolio for purposes of determining revenue requirement, power costs, rate base, etc. To prevent customer cross-subsidization of VRET resources and services, utility investment in resources for VRET service must be financed and accounted for based on the VRET customer base and level of service only. The range of other costs for the utility to serve a customer under the VRET (e.g. customer relationship services, marketing, billing, etc.) should be accounted for separately and recovered solely through the VRET.

- **Renewable NW**: Utility capital investment complicates VRET design in terms of competitiveness and risk to non-participants. It would be appropriate for VRET customers would be responsible for paying the utility's cost of capital, at least for above-market resources.
- **PGE**: No support for separate set of resources for VRET customers with separately accounted for capital. PGE's proposed model where the PGE aggregates subscribers involves the renewable energy resource added to rate base at a null power cost. Power produced available to all PGE customers as part of PGE's fleet of generating resources. RECs would be claimed by the VRET customers that are paying a premium. By rate basing at null power cost, PGE provides power for all customers and has opportunity to earn a return on the capital used for null power cost portion only.
- **Pac**: Costs and return on VRET resources will be subject to Commission review as part of review and approval of bilateral contracts authorized by VRET. These resources should be separate from existing rate base, but does not view potential VRET resources as comprising a separate "VRET rate base."
- **Shell**: Reject Model 2 and 2.c/d because these VRET structures would inhibit the competitive retail market.
- **WRI**: VRETs are fundamentally a market priced product rather than a cost of service product. Ensuring customers can reasonably access alternative offers is sufficient, for example, by not permitting model 2 without also permitting model 1 and 3.
- **NIPPC**: If a utility wants to offer VRET service, it should be done through an affiliate with separate accounts.
- **ICNU**: Utilities have indicated to date that they will not offer a VRET in a competitive market through an affiliate because it is administratively challenging to set up. Cost shifting is a concern. VRET rate base concept should be rejected.

6. **With respect to *Model 2(c/d) [regulated utility owned resource with aggregation]* and *Model 1(c/d) [third party owned resource with aggregation]*, if the regulated utility is allowed to aggregate retail load through a VRET, how should the regulated utility manage the risk and timing of the matched VRET load and/or the obligations to the aggregated RE generators?**

- **Iberdrola:** The utility should manage VRET load and resources matching in the same manner and degree as an ESS manages loads and resources for a direct access customer. This may mean it does not manage that match. This illustrates why utilities should not play the aggregator role.
- **Renewable NW**: Reference to CA example in IV.2. Best approach involves waiting for customer commitments before committing to new resources and serving those customers with a transitional renewable option until resources come online.
- **PGE**: No interest in taking on risk of undersubscription. Size and cost of renewable resource would determine the premium price and number of subscribers necessary to realize it. PGE has not surveyed for demand.
- **Pac**: This issue should be addressed when and if utility decides to file a tariff and as part of Commission approval. Any VRET load during specified time periods not simultaneously served by a VRET resource should be subject to applicable PUC approved tariff.
- **Shell**: Utility should not be allowed to aggregate customer load or renewable energy supply to establish a new supply portfolio and/or a new market for incremental renewable supplies. Utility is provider of "default" cost of service, including requisite renewable energy to meet its RPS obligation. Utility should not compete with its own cost-of-service or with direct access. Utility should not promote or encourage customers to purchase their energy from a separate supply portfolio established by the utility. Any risk with matching customer load with incremental renewable energy supplies can and should be addressed by renewable suppliers and customers.
- **WRI**: Another utility in another state is considering this issue. They are putting the risk of under subscription into their voluntary unbundled REC green power pool, which is large enough that they impact on customers would be negligible compared to RECs price volatility. More generally, we see development of MOUs as different

market participants line up the many pieces necessary before moving on to contracts. Through this, they simultaneously bring together load and resources. This could be done even more transparently in a bidding process for price discovery but that may be more complicated than needed to find a least cost product offering.

- NIPPC: Under the direct access VRET model, these risks are borne by the ESS and not the utility or its customers.
- ICNU: This option is inappropriate. If such a structure was adopted, the utility must solely bear the risk created.

V. Whether VRETs should rely on a Competitive Procurement Process? *(issues related to HB 4126 Section 3(3)(d))*

- CUB: The utility as a facilitator model answers this question with Yes. Customers are identifying options and asking the utility to help them bring those options to fruition. Utilities may help identify opportunities that could benefit various customers and provide information about those opportunities to those customers but their role would ultimately be the same – facilitate the relationship between a customer and a provider or between a customer's resource and the rest of the system.

1. Should the Commission limit VRET resource eligibility to renewable energy developed and supplied through a competitive procurement process? With an independent evaluater? If yes, why? If no, how should the Commission evaluate renewable energy not supplied through a competitive process?

- Iberdrola: Depends on the model adopted. Except for models 2 and 2.c/d, there should be flexibility in allowing bilaterally arranged transactions to qualify.
- Renewable NW: In a c/d type model (utility aggregates resources), a fair, open competitive procurement should be required. In a b/x type model (third party owned resource & regulated utility facilitated), customer can find competitively priced supply. These customers may have preferences, expertise, or market connections.
- PGE: No. Reasons for using a competitive procurement process to develop a least-cost resource for the entire customer base do not apply. Competitive marketplace would force efficiencies because of customer choice. This process and an independent evaluator would add administrative costs, which would raise prices for customers. If there are customers interested in paying a premium and the objective is to further development of significant renewables, then the PUC should balance the supply of the renewable energy with the objectives achieved. VRET resource eligibility should be based on the certification of RECs and not based on the competitive bidding process related to construction and siting of projects.
- Pac: Utility owned VRET resources over 100 MW should have requirement to use competitive procurement process, consistent with existing competitive bidding guidelines. But, for smaller projects, no need for competitive bidding process. VRET is a customer driven option that a customer will only select if the price for the offering is competitive. Additional PUC oversight to ensure competitive options is not necessary – if there are not competitively priced options, customers will not sign up.
- Shell: No, utilities should not be engaged in soliciting renewable energy supplies beyond those resources necessary to meet RPS obligations for their cost-of-service supply.
- WRI: Approaches range from utility finding resource, customers brings resource desired to utility, or where utility owns resources. But this is a fundamentally market price product, rather than a cost of service product. Market participants should seek to provide lowest cost products, which is maximized when customers find a lower cost offer than the utility and the utility cannot block or discriminate against those opportunities. This may be hard in a model where the utility aggregates resources, but if other market participants can offer altneratives then this risk is minimal.
- NIPPC: A competitive procurement process is not necessary for a direct access VRET where suppliers are limited to ESSs and utility affiliates because market forces will insure competitive procurement. If the utility is otherwise engaged in providing VRET service in any manner, a competitive process should be required.
- ICNU: Current regulations should not be weakened, if a utility procures a VRET resource.

- **Noble:** Yes. At a minimum, all applicable RFP requirements from UM 1182 should apply regardless of the size of the VRET generation resource if there will be a utility ownership option. However, the VRET program should not be used as a vehicle to add to the utility's rate base because allowing for that opportunity is highly likely to shift costs to other customers and harm Oregon's competitive wholesale and retail market for electricity.

2. **Should the PUC's existing processes for competitive bidding (currently for "major resources" defined as quantities greater than 100 MW and duration greater than five years [UM 1182, Order Nos. 12-007 and 11-340]) be adapted for use with VRET resources and, if so, how should it be changed?**

- **Iberdrola:** Depends on the model adopted.
- **Renewable NW**: PUC existing process could be a starting point, if a c/d type model is proposed.
- **PGE**: No, should not be used.
- **Pac**: Utility owned VRET resources over 100 MW should have requirement to use competitive procurement process, consistent with existing competitive bidding guidelines. But, for smaller projects, no need for competitive bidding process.
- **Shell**: No.
- **NIPPC**: Yes, if utility owned generation is considered for a VRET at all, the competitive bidding process must be modified to apply to any resource used to serve a VRET, without exception and regardless of the duration.
- **ICNU**: Current regulations should not be weakened, if a utility procures a VRET resource.
- **Noble:** Prefer no utility ownership option.

3. **With respect to *Model 2 [regulated utility owned resource]* and *Model 4(a/x) [customer owned resource]*, is there any room for a competitive procurement process in these models?**

- **Iberdrola:** Under Model 2, there should be room for a competitive process, even if the utility ultimately owns the resource, as the process would deliver better customer results. For a customer owned resource (Model 4 a/x), that choice should be left to the customer.
- **Renewable NW**: Model 2 is a bad idea and leaves little room for competitive procurement. For b/x type models, competitively prices supply can be left to customer, including deal structures with customer ownership.
- **PGE**: If utility owns resource, then engineering, procurement, and construction processes could go through a competitive procurement process.
- **Pac**: Utility owned VRET resources over 100 MW should have requirement to use competitive procurement process, consistent with existing competitive bidding guidelines. But, for smaller projects, no need for competitive bidding process.
- **Shell**: No, utilities should not engage in soliciting renewable supplies beyond RPS for cost-of-service supply.
- **NIPPC**: Model 2 – regulated utility-owned resource does not warrant further consideration because it does not pass the statutory hurdle of not harming the competitive retail market. A utility should not be permitted to use existing renewable generation to provide VRET service, because such generation should be already dedicated to the existing customer base. As such, any new VRET generation must be newly purchased, and should be subject to competitive procurement. While supportive of customer owned generation, model 4(a/x) (customer owned resource) does not warrant further consideration as a VRET solution because it does not pass the statutory hurdle of promotion of significant new renewable resources because model limitations prevent development of significant new load. If considered, competitive procurement is unnecessary because the competitive market will ensure customers strive for the best solution.
- **ICNU**: Under model 2, there is need for competitive procurement. Under Model 4(a/x) there is not.
- **Noble:** Prefer no utility ownership option.

4. **With respect to *Model 2(c/d) [regulated utility owned resource with aggregation]*, what regulatory tools or VRET design elements would ensure that a regulated utility-owned resource fairly competes in a competitive procurement process?**

- Iberdrola: Not clear that any design elements would meet this goal, which is why the other models are a far better approach.
- Renewable NW: Start with PUC existing process. Some experimentation is warranted to because it's been perceived as unsatisfactory in overcoming utility ownership bias.
- PGE: IRP regulatory tools may be used to ensure costs are prudent.
- Pac: Utility owned VRET resources over 100 MW should have requirement to use competitive procurement process, consistent with existing competitive bidding guidelines. But, for smaller projects, no need for competitive bidding process.
- Shell: No, utilities should not engage in soliciting renewable supplies beyond RPS for cost-of-service supply.
- NIPPC: If utility owned generation is considered for a VRET at all, the competitive bidding process must be modified to apply to any resource used to serve a VRET, without exception and regardless of duration.
- ICNU: Current regulations should not be weakened, if a utility procures a VRET resource.

VI. Other considerations *(issues related to HB 4126 Section 3(3)(e))*

1. **What customer protections may be appropriate for VRET resources (e.g. Green-E certification? Commission or advisory group oversight?)? For which customer classes or subsets of classes?**

- Iberdrola: There should be a range of protections: minimum eligible RE requirement (set in tariff), public disclosure of RPS/VRET service that supplants current utility fuel mix disclosure requirements, and registration/tracking/retirement of RECs in WREGIS. Customer representations of "green energy" should be consistent with the disclosures made by the serving utility.
- Renewable Energy Markets Association: Utilities and energy suppliers should accurately describe their RE purchases and sales when disclosing their generation portfolios to VRET customers. Null power is assigned system emissions average when the associated RECs have been sold separately. Must avoid allowing renewable claim on null power because it negatively impacts REC transactions inside and outside the state where the utility or supplier operates.
- Renewable NW: For the c/d (utility aggregates resources) model, oversight should aim o ensure the most cost-competitive eligible renewables matching customer preferences are procured, so that customers can make the claims anticipated, with Green-e certification or a customer advocacy group. For the b/x (third party owned resource & regulated utility facilitated) model, customers could use Green-e Direct to help them ensure their chain of custody and claims are valid.
- PGE: Customers participating in a potential VRET offering are likely informed/sophisticated large non-residential customers and not in need of the same consumer protections provided for residential customers. PUC oversight with active stakeholder involvement is ample protection for participating and non-participating customers.
- Pac: Not aware of any need to change existing customer protections, but support mechanism to ensure non-VRET customer protection.
- Center for Resource Solutions (CRS): Green-e certification should be required as it is the standard for quality renewable energy in North America. It mandates rigorous accountability for retail products sold to consumers with a level of transparency to bolster consumer confidence in the industry. EPA's green power partnership strongly encourages the purchase of products that are certified by an independent third party. Green-e certified retail sales of 33.5 million MWh in 2013, enough to power a quarter of US households for a month. Green-e currently certifies 1% of the total US electricity mix. Compared to 2012, nearly 47000 more retail customers purchased green-e certified renewable energy in 2013, with almost 717000 total retail customers, including

69000 businesses. Non-residential buyers accounted for the vast majority of certified MWh purchased, at over 30 million MWh. In 2013, certified bundled REC options were available in 35 states. Also recommends retirement of RECs in WREGIS to reduce potential for double counting and ensure accounting/retirement.

- Noble: Product should be ODOE RPS certified.
- ODOE: It will be important for VRETs to have a framework that ensures that these products have adequate oversight and conform to renewable energy and environmental attribute markets. Green-e is probably the most appropriate existing model for customer communication and resource eligibility. Certification would ensure that the programs meet national standards and evolve over time, allowing growth outside of a strict statutory environment. Both Pac and PGE's voluntary programs are Green-e certified. Given the complexities of the mandatory and voluntary market interactions under current frameworks, there should not be yet another public facing resource framework for delivering renewable energy to Oregonians. It is appropriate for the study to consider how the Commission currently oversees RPS compliance and voluntary programs and determine whether those tools – reconciliation reports, compliance reports, and an advisory committee – are suitable for the VRET. Administrative simplicity for the utilities should be a significant factor in this determination.

2. **How will resources developed for a VRET, for which environmental attributes will be claimed by customers, be represented in power mix disclosures (e.g. regulated utility disclosures pursuant to OAR 860-038-0300)? Assuming that a VRET could be used for partial loads with continued use of the existing cost-of-service rate based system, how would such a customer claim its renewable resource use (e.g. claim a portion of the RPS in its "green" marketing)?**

- Iberdrola: Public disclosure of RPS/VRET service that supplants current utility fuel mix disclosure requirements. Customer representations of "green energy" should be consistent with the disclosures made by the serving utility.
- Renewable NW: Renewable energy paid for by VRET customers should be represented as null power or brown power for system power supply disclosures to cost of service customers to avoid potential double claims for VRET customers. Utility generation or capacity reporting could be different, if presented clearly. In theory, customers maintaining a connection to standard cost of service RPS supply should be able to claim utility-supplied RPS renewables as part of a 100-percent renewable energy supply, if the utility supplied RPS renewables meet the customer's quality and recency requirements (Green-e, etc) and the customer adds voluntary renewables on top – but this emerging area may need specific rules in the future.
- PGE: Resource mix disclosures for VRET would be treated similar to the utility labeling requirement for resource mix disclosures. Customer's renewable resource mix percentage based on VRET generation output as percentage of customer's total annual kWh use. Percentage of RPS portion of utility generation could be applied to customer's total annual kWh consumption, less the VRET resource contribution, to determine RPS component. Customer would then add the VRET and RPS percentages to determine their total renewable usage.
- Pac: VRET load, either partial or full, will not be included in utility's load for purposes of determining levels of retail sales for purposes of utility's power mix disclosure. How a VRET customer chooses to claim their renewable resources for purposes of marketing or other business related communication is outside scope of HB 4126.
- Shell: If environmental attributes (including but not limited to RECs) associated with enhanced renewable energy procurement are conveyed to customers, then those attributes cannot be claimed by utility. Only if the environmental attributes (including RECs) are transferred to the utility may it reflect them in its power mix disclosure. Model 1.b or 1.b/x relies on customers and renewable energy suppliers to establish terms of sale and delivery of incremental energy supplies to the utility. One key term to be negotiated is whether environmental attributes will be transferred from the supplier to the customer. Whether they are or are not transferred, the incremental supply is not part of the utility's supply portfolio, and the environmental attributes should not be reflected in the utility's power mix disclosure.

- WRI: Corporate greenhouse gas accounting guidance and Federal Trade Commission rules set what can be credibly claimed. A company can claim the RPS proportion of utility electricity. It could also claim the energy it purchases from the utility via RECs that were transferred to it or retired for it in a credible tracking system. The utility could not claim the RECs retired on behalf of customers for the RPS or another purposes. However, most existing VRET-like rates in other states have not been explicit about how to handle this issue.
- ICNU: Renewable resources developed for a VRET should be represented in the utility's power mix disclosures if and to the extent that the loads are reflected in the utility's retail sales.
- Noble: VRET customers should receive a different product mix label than the bundled utility customers.
- ODOE: Environmental attributes should be claimed solely by VRET customers through the individual customers' marketing materials or other communication channel. If one product is designed for all VRET customers, the resource mix associated with the VRET could be included under OAR 860-038-0300. Including it in the retail label would allow customers to compare what resources they are receiving against the base utility mix. If a specialized product is created for individual customers including the resource mix for the VRET product would be difficult.

3. What other factors, if any, should the Commission consider in determining whether and how utilities should offer VRETs to non-residential customers?

- Pac: Take into consideration the competitive business market and potential for economic development when examining whether VRET is a useful tool for Oregon utilities to offer. To extent that regulatory policies supportive of increased use of renewable energy and low or zero emission generation can harmonize with state economic and business development goals, Commission should consider these factors in deciding on a VRET.
- Shell: Commission should consider whether complexity associated with VRET implementation is worth the effort. Commission can promote the further development of significant renewable energy resources and encourage development of a competitive retail market by allowing renewable energy suppliers and customers to engage in enhanced renewable energy procurement through direct access. Changes to direct access, including a more liberal customer enrollment process and less onerous transition adjustment mechanism, would encourage nonresidential customers and renewable energy suppliers and marketers to participate in direct access. With unlimited competitive procurement options available through direct access, customers in direct access will be encouraged to increase their renewable energy procurement beyond minimum levels in the RPS. By contrast, demonstrated by the range VRET models, VRET implementation will be complicated. Any VRET creates risk of stranded capacity, cost shifting, and exercise of market power by utilities. Any VRET approach creates need for another layer of utility administration, with additional costs associated with billing, promotion, and customer service.
- WRI: large sophisticated and energy-intensive businesses see advantages in renewable generation to avoid fuel price volatility and want access to renewable energy near their facilities. They emphasize having choice among suppliers and products for business goals. Such business (e.g. technology sector's data storage and processing operations) can shift operations, output, and employment among existing locations quickly and easily. Being able to offer VRET renewable energy that reflects actual costs of generation, transmission, and distribution can bolster Oregon utilities and help the economy with jobs. If utilities can compete with a VRET, it could strengthen the utilities' financially, with benefits like lower costs of capital for their traditional non-VRET customer base. Expanding the potential market for IPPs and ESSes with competitive procurement could strength their financial base too. Conversely, the loss of large existing or potential customers could lead to underutilized facilities and stranded costs, which adversely affect the utilities and remaining customers.
- NIPPC: With the Commission's decision of whether to allow utilities to offer a VRET, the Commission should consider potential market changes that may occur from three factors: (1) 111(d) compliance, (2) continued movement away from the central utility model and towards more distributed generation, (3) renewable energy price parity with fossil generation, and (4) the utilities' continued obstinacy in working towards a solution to the VRET issue in the best interest of Oregon. The utility industry continues to change with numerous and complex challenges that the Commission will face in the coming years. The Commission should not create a special plan,

and subject staff and interested parties to countless expensive regulated proceedings, to allow the utilities to do something they already can do simply by forming an affiliate.

- **ICNU**: The concept of no cost shifting is a key element. Otherwise, a VRET should be broadly available to all eligible customers using competitive resources.
- **CUB**: Need to focus on some particular area to make progress (paucity of ideas from utilities). At the same time process is best served with solution that can applied in many different circumstances. Urge staff and parties to pursue discussion around direct access and utility as a facilitator. The question of how direct access can provide solutions for customers to access more renewable energy should be discussed – this is a very particular issue that was not a factor when direct access was originally constructed. There should be a focused discussion on how a utility can facilitate interactions between customers and third party power producers and consider customer owned resources as a subset of the utility facilitation model. In the absence of specific proposals, defining the utility role will help to give rise to potential relationship constructs that will help to define an overall VRET category. Any VRET discussion should ensure that every effort is being made to acquire every bit of least cost resource before expensive resources are acquired – the Commission should require that any VRET participant is assisting to acquire all cost effective energy efficiency as they pursue more renewables. Having utilities serve in the role of a facilitator permits that kind of approach because they can help customers work the ETO.