To: Oregon Public Utility Commission
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From: Renewable Northwest
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Re: *Phase 1* – General Comments, Issues List Responses, and Summary Table Comments

Date: December 12, 2014

Renewable Northwest (Renewable NW) appreciates the efforts of the Oregon Public Utility Commission (OPUC) to explore the voluntary renewable energy tariff (VRET) purpose and design in Phase 1 of this docket. Before responding to some of the thoughtful and detailed questions in OPUC Staff's Issues List, we begin with general introductory comments.

General Comments
(pages 1-3)

VRET is good policy. If a VRET can motivate incremental, new renewable energy development by harnessing customer demand for renewables that is not satisfied through other channels, then the OPUC should strongly support VRET development. Finding an effective path for motivated customers to drive incremental renewable energy into the system can bring our communities the economic benefits of renewable energy development and our electric system greater diversity and a lower carbon profile, while bringing long-term economic benefits to those motivated customers.

Moreover, customers' on-site options will continue to improve. By beginning to experiment now, the state can find effective ways to channel some of this demand for clean energy into the integrated system. Maintaining a level playing field will give customers a diverse array of avenues for accessing new renewables from utilities and renewable energy businesses.

VRET is complex and evolving, yet feasible. Direct renewable energy purchasing within the regulated utility environment is an emerging trend to which Oregon can make a significant contribution. This also means that examples from other jurisdictions are diverse and varied, with no single best practice yet emerging, plenty of room for tailoring programs for different environments—and, admittedly, a great deal of effort and new thinking required to establish a new program.

Two main approaches seem to be emerging. In one, 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. Commonly, 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. A direct project linkage approach may appear somewhat similar to, and thus would need to be explicitly differentiated from (or, alternatively, linked to) Direct Access.

Another approach is more comprehensive, with the utility procuring by RFP an aggregated portfolio of resources (or a single resource) for an aggregated pool of participating customers. This type of approach theoretically could be integrated more comprehensively with utility IRPs and RFPs. VRET renewables 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.

Both types of options could be relevant and attractive to different customer segments. Oregon should consider both, in time. ***Renewable NW recommends that Oregon move quickly toward a pilot VRET program that allows customers to connect to particular projects, using the less comprehensive approach. We believe this is a reasonable first step and recommend that the pilot program be established by the end of 2015. A pilot should establish a goal of serving at least 150 MW to capture initial demand.*** This will not satisfy all types of customers, and OPUC should be open to future phases that develop more comprehensive, integrated purchasing programs.

Either way, any design should allow customers to access competitively-priced renewable energy, because competitive pricing is the key to bringing customers in the door and allowing a VRET program to deliver the benefits of expanded renewable energy development.

<u>**Phase 1 VRET study can illuminate sideboards, but allow continued evolution**</u>. The Issues List represents a very comprehensive list of questions that will need to be answered about any VRET proposal made in future phases of the docket, and the matrix is a very general representation of model types that can be shaped into specific, detailed proposals in future phases. Many of the questions in the Issues List cannot be answered definitively until a specific VRET proposal is framed, and an actual VRET proposal will inevitably raise questions not anticipated in the Issues List. The answer to any given question may depend on which type of model the respondent has in mind. We have answered the questions to the best of our ability at this stage, while recognizing that the list represents a sort of "minimum filing requirement" for any future testimony in support of a particular VRET proposal.

Renewable NW encourages the OPUC to use the Phase 1 study to illuminate the contours of the issues that a VRET proposal would need to address and identify areas of agreement and disagreement. While illuminating the sideboards will help relevant parties craft VRET proposals, we would caution against using the Phase 1 study to fully endorse or condemn a particular proposal. Certainly, the OPUC should not close the door on the VRET concept in general because a clear proposal has not yet emerged or because questions remain to be answered definitively. In this emerging field, space for education and creative engagement should be left open, while the OPUC shapes the discussion by noting any parameters or particular areas of concern that any proposal should address.

At this stage, Renewable NW encourages the Commission to pull back and take a higher-level view of the questions. Can a VRET promote more renewable energy supply that benefits our economy, communities, environment and electricity system? Can a VRET coexist with Direct Access? Can a VRET appropriately balance the interests of participating and non-participating customers? Can a VRET be structured to give customers access to the most competitively priced renewables on the market? In our view, the answer to all of these questions is "most likely, yes." The Commission should look to parties to make a specific proposal for at least a 150 MW pilot program before June 2015 to move the process forward toward a VRET proposal that can answer all of the questions with a definitive yes.

Issues List Responses
(pages 3-18)

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

A VRET supports incremental renewable energy development by allowing a customer of a regulated utility to purchase and receive the benefits of more renewable energy supply (or different renewable energy supply) than it receives from the utility's basic service mix. The benefits may include the right to claim the environmental attributes, to publicize the specific source of energy, and to enjoy the predictability of stable renewable energy prices.

A VRET is a complementary alternative to other renewable energy supply options. It is different from existing on-site options (*i.e.*, net metering) because it provides access to off-site resources (as well as on-site resources not captured by current on-site generation policies) that may offer improved quantity, quality, and cost-competitiveness and may benefit the entire utility portfolio. It is likely different from Direct Access because ultimate load service and billing is utility-managed, and many VRET designs do not schedule renewable energy to match the exact demand of a specific customer. It is different from unbundled REC purchasing because customers get more than the environmental attributes in exchange for their investment, and direct purchases of bundled energy from new projects support the renewable energy market in a different way than most REC purchases—i.e., by driving single projects rather than driving up aggregate demand.

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?

Essential Features. From a public policy perspective, the essential features are well stated in HB 4126. For Renewable Northwest, the key feature is that the VRET drive new renewable energy development that is incremental to existing policies (*i.e.*, RPS).

The customer perspective on essential features of a VRET is important, because a VRET can stimulate additional, incremental renewable energy demand only if it is attractive to customers. The Corporate Renewable Energy Buyers' Principles gathered by World Resources Institute and World Wildlife Fund are a good starting representation of what motivates the largest corporations in renewable energy purchasing. Rocky Mountain Institute is joining those organizations in work to evolve these principles into specific and concrete recommendations. These organizations are in the early days of national-level work to help shape this emerging model.

Beyond these general large corporate principles, customer priorities can vary significantly. One significant distinction among customers is the amount of time investment the customer wishes to make and the amount of expertise it brings to energy transactions. Some have internal energy expertise and so desire the flexibility to do their own deals, while others may want to be able to "check a box" provided by the utility. Related to that distinction may be a difference in the degree to which customers desire to keep their service closely connected to their utility.

Another significant difference among customers is how they evaluate the financial benefits and environmental claims from renewable energy purchasing. Customers may evaluate future risks very differently in determining whether to pay a premium against present costs (if such a premium exists at all). Others may be less price sensitive and more heavily focused on environmental claims.

One element that we do *not* regard as essential to a VRET is having the renewable energy supply scheduled and accounted for precisely to match the specific customer or customers' load. Mimicking an on-site project or establishing a direct access-type supply relationship has not been a feature of recent green tariff programs. A simpler, more streamlined approach is available by having customers 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. This can reduce administrative burden and cost while maintaining participating customers' responsibility for system costs.

More than one VRET Design. Ultimately, having two distinct VRET products would best capture diverse customer preferences. One product could enable customers with particular preferences and expertise to connect to specific projects, and another could offer a fairly simple path to participation in an aggregated VRET portfolio. The former may be an easier product to design initially, but the latter may be more scalable and capable of capturing the full benefit of customer choice to have more lasting influence on the utility portfolio and on new renewable energy development.

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?

<u>IRP Relationship</u>. IRPs will need to examine VRET in one way or another. If the VRET product enables customers to select and connect with specific projects, then VRET energy supply would likely be assessed and accounted for in IRP much like Direct Access demand currently is (although likely more on the energy side of the load-resource balance equation). IRP flexibility and integration studies would need to consider VRET demand, if it influenced renewable energy penetration enough to affect the need for intrahour flexibility. An initial MW pilot program cap of 150 MW (or more) would help with this planning initially.

If parties are willing to consider an aggregated VRET product, it is worth considering how VRET load planning could be integrated into resource planning and procurement. This is a very preliminary concept for discussion: IRPs examining renewables to supply RPS or general resource needs could examine portfolios with more renewable energy, assess the cost difference in using more renewable energy to meet utility's resource need, and solicit customer initial interest based on that cost difference. The utility could incorporate VRET load into its RFP process as an add-on bid, and get binding customer commitments during the evaluation of actual RFP bids and before committing. Incorporating VRET demand into resource planning where there is already a resource need could be a basis for addressing transition charges differently, which potential VRET customers have raised as a significant obstacle associated with the current Direct Access structure. While preliminary, this concept is presented here as a thought experiment to see how customer demand for cleaner power could influence the utility's portfolio choices in a more integrated way and potentially reduce costs for VRET customers.

<u>Total Retail Sales</u>. This question is addressed below, in Question IV.4. We are unsure what implications, other than RPS interaction, the concept of "total retail sales" may have.

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

In time, a VRET product should be available for all non-residential customers. Once a non-residential model is developed, utilities and the Portfolio Options Committee may wish to consider implications for the evolution in residential customer choices. Initially, however, it may be worthwhile to consider a smaller subset of larger customers, including larger customers with multiple service locations, in a pilot program sized 150 MW or greater.

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)?

It may be worthwhile to experiment with smaller load segments initially; we recommend no less than 150 MW initially. But we encourage all parties to strive to build a VRET structure that can scale up to ultimately capture all utility customer demand for new renewables.

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?

A VRET should be flexible enough to serve all or part of a customer's load at any POD and should enable aggregation of multiple PODs.

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?

These questions assume that there is a single "VRET load" that a utility will serve in a centralized fashion—i.e., a "c/d" type model. In that type of model, resources could be aggregated to serve an aggregated customer demand. Disclosure would depend on the manner of procurement, but could easily be communicated as a proportional mix supplied to each participating customer.

With respect to an "b/x" type model that enables customers to connect with specific projects, a customer should be allowed to bring on multiple renewable resources if needed to produce the amount of energy usage the customer wishes to offset.

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)?

Not all renewable energy generation is variable, and not all variable renewable energy generation is variable in the same way. A VRET model needs to be able to accommodate different types of renewable generation effectively—from solar and wind to irrigation hydro to biogas. The best way to accommodate this diversity seems to be to replace the energy cost with the energy value (including ancillary services and other benefits) and provide a credit against fixed cost for the renewable energy project (or portfolio) capacity contribution. For renewables with intrahour variability, a standard integration charge could be appropriate.

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

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?

In general, there should be a level playing field between renewable energy supply under Direct Access and a VRET product. However, for a VRET product to be worth developing as an additional option for customer renewable energy supply, then it will need to have some substantive differences from Direct Access that enable it to satisfy customer demand in ways that Direct Access cannot. Those differences will likely warrant some differences in implementation details. However, differences should not favor one program or another, but rather only reflect substantive program differences.

Where a VRET is similar to renewable energy supply under Direct Access, then the programs should operate in similar ways. For instance, if a VRET can offer a more user-friendly enrollment time period, changes to enrollment windows should be considered for renewable energy supply under Direct Access too. If there is no rationale for difference, similar treatment should be the norm.

Transition charges are a good example of where a rationale for different treatment may or may not exist, depending on VRET design. If the VRET is designed to allow customers to elect to take load completely off the system to a new resource portfolio and bring it back with relatively little notice, then the rationale for treating the VRET differently with respect to transition charges is more difficult to identify. The underlying rationale for transition charges—*i.e.*, that the system has already been planned and built to accommodate the load—would be affected in the same way as with Direct Access. However, if a VRET product were a less comprehensive departure from the cost-of-service system or fundamentally integrated with IRP planning, especially if customers made advance elections to a portion of a utility portfolio not yet planned and built and made long-term commitments to that portfolio, there would be reasons for handling transition charges differently. Similarly, if the VRET rate design involved customers continuing to pay a large portion of their cost-of-service demand charges while offsetting energy charges with a new renewable project, then the customers may already be paying all or most of what transition charges compensate.

In short, where elements of the Direct Access program are inflexible and not user friendly and the VRET model improves on those, then these improvements should extend across programs to support a range of renewable energy supply options. If a VRET model is different enough from Direct Access to adopt, however, there will inevitably be places where a reasonable rationale supports different implementation details. The Commission should take care to ensure a level playing field for renewable energy supply across different options designed to match different customer preferences.

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

Energy Service Suppliers are free to offer any options for energy supply that their customers desire, including renewable energy as a portion of the portfolio that the ESS uses to meet the customers' load.

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?

Yes, there very likely are ways to improve Direct Access to improve customer access to renewable energy. It is worth considering whether a specific renewable energy option could be developed under Direct Access. Given the significant differences of opinion from VRET workshop participants regarding how to best improve Direct Access or if it is feasible to improve, we recommend the 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 for the purposes of supplying customers with renewable energy.

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, but 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)?

The underlying policy reason for adopting a VRET is to promote new demand for renewable energy, and Renewable NW favors a VRET *only* if it supports new renewable resources built specifically for the VRET product. As Renewable NW stated in our Statement of Principles in this docket:

> "A VRET should serve customers primarily with RPS-eligible renewable energy resources that are brought online specifically to serve the VRET. If needed for bridging between customer elections and new project online dates, a VRET could allow for temporary use of RPS-eligible renewable energy resources of recent vintage that are new to the utility's portfolio and not otherwise required to be added (*i.e.*, to meet RPS or PURPA requirements)."

We note that Green-e has recently considered amendments to its National Standard to recognize long-term commitments to new renewable energy projects. They proposed and took stakeholder comment on rules that would require the generation unit and purchaser needed to have signed a contract within six months of the generation unit's commercial online date. If a timeline following construction is considered for inclusion in a VRET portfolio, it should be no longer than the ultimate Green-e requirement.

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)?

There is nothing in HB 4126 that specifies that renewable energy development be promoted in a specific state or region. The program will support renewable energy best if customers have access to the most competitively priced renewable energy resources and those that support their particular resource preferences. Some customers will prefer resources that are closer to their load.

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)?

A VRET should supply only renewable resources. Direct Access already offers a path for blending with market or other resources. While customers should have flexibility to determine how much of their load to supply under a VRET product, the minimum must be more than the proportion served by the utility's RPS requirement. The VRET should very clearly be an above and beyond option.

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

Promoting further development of new renewable energy resources is less about the model selected and more about the Commission adopting parameters to ensure that VRET supply is incremental to renewable energy required to be added under other policies, and that it is new supply that promotes renewable energy expansion in the region.

With that said, the model that is most popular with customers will be the one that best promotes incremental development of renewable energy resources. As discussed above, different customers have different priorities, and having at least one model that gives customers flexibility to accommodate those priorities is critical. After those highly motivated and sophisticated customers are satisfied, having a scalable, aggregated check-the-box option may do the most to promote further renewable energy development beyond existing policies.

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

Before answering the questions in this section, it is worthwhile to distinguish this section of HB 4126 from Section 3(3)(d). As we understand it, this Section 3(3)(b) examines the effect of a 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. Section 3(3)(d), by contrast, has less to with the structure of who customers look to as an energy provider, and more to do with whether the renewable energy supplied under a VRET benefits from the kind of fair, open competition among supply options that produces the lowest-cost resources for customers.

In general, a VRET model that opens up an additional avenue for connection between customers and renewable energy developers (i.e., an "b/x-type" model) should positively impact the development of a competitive retail market because it encourages customers to think about different supply choices—including evaluating Direct Access as an option. A more aggregated VRET model (i.e., a "c/d-type" model) is less supportive of development of a competitive retail market, but in theory does not impact the same customer profile. A customer likely to buy into an aggregated product in which the utility drives procurement is not likely to be one for whom Direct Access, even with significant improvements, is likely to be an attractive option.

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

The goal of a VRET should be to give a path to renewable energy for customers who are unwilling or unable to use Direct Access, even with improvements to that program. Being clear about the differences between and advantages and disadvantages of the Direct Access and VRET paths from the beginning will ensure that VRET is incremental and different from Direct Access, but that the design does not unduly favor the VRET product where a level playing field can be achieved. Making the VRET very clearly an incremental renewable energy supply option may help to distinguish this, so that customers looking primarily for undifferentiated cost savings and a blend of renewables and market purchases can remain primary candidates for 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?

Not necessarily. See answer to Question I.6(a), regarding a premise of level playing field with room for well-supported differences.

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]**:

Before answering these questions, it is worth noting that these two models are quite different in terms of the utility's role, and therefore can be expected to have quite different implications for the competitive retail market.

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?

This approach maintains *competition*, in the sense of HB 4126 Section 3(3)(d)—i.e., it allows market participants other than utilities to develop and own and operate projects. The question seems to ask, though, whether a VRET product will attract customers that would otherwise consider Direct Access. Our premise is that a VRET can be designed to be complementary to Direct Access and offer customers who are unlikely to move to Direct Access, even if improved, an opportunity to access independent renewable energy supply through a less comprehensive alternative retail supply model. It is reasonable to regard this as increasing demand for new renewable energy supply that would otherwise go unfulfilled, rather than reducing demand for renewable energy supply through Direct Access.

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?

The utility's role is significantly different between the two referenced models. In 1(b/x), the utility facilitates a transaction for energy reached between a customer and renewable energy supplier/IPP, but continues to meet customer demand and maintains the primary billing role.

In 1(c/d), the utility takes control of an aggregated product, promotes it to customers (potentially using a third-party marketer), and procures renewable energy to supply it.

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)?

<u>Tariff definition</u>. Yes. Even a VRET model that facilitates individual customer transactions for renewable energy, in which renewable energy supply prices will vary and not be explicitly listed in tariffs, can clearly state all other charges. (The competitive bidding portion of the solar VIR pilot program is an example where a tariff does not state the exact price.) If necessary, the statute appears to offer the opportunity for alternative forms of regulation plans, including resource rate plans. *See* ORS 757.210-.212.

<u>Pricing confidentiality</u>. 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 to program success. If transmission arrangements can be interpreted to allow

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 the confidentiality issue under the (b/x) type model. If this is not an option, then clear, effective firewalls need to be established within the utility to handle this issue. Independent third party assistance might be useful to accomplish this with appropriate comfort for all parties.

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)?

No. The whole point of a c/d-type model is for the utility to play the role of aggregating customers who are not motivated to seek individual transactions in the market. Even for a b/x-type model, a customer should be able to work with a utility to aggregate meter locations through the utility without using a separate aggregator.

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?

Effects on the competitive retail market are much more pronounced if a regulated utility can own resources as part of VRET design. For competition generally, this would require more robust protections against ownership bias. If an IPP and customer were to agree on an arrangement for a utility to operate the resource, it is not clear that similar concerns would arise.

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

A customer should be treated the same as an IPP in thinking about VRET design. Presumably a customer could own and operate an on-site or off-site resource as part of a Direct Access supply portfolio without raising concerns about damaging the competitive retail market.

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

Partial requirements tariffs seem to be designed for on-site, non-variable customer generation. It is unclear whether these would even be available to variable generation, and certainly the cost structure would be different if the partial requirements tariffs had been conceived originally for variable generation. Moreover, customers may wish to own off-site generation, or combine off-site generation with on-site generation for renewable energy supply.

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])?

See answer to Question III.3(c).

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?

An off-site customer-owned resource (and on-site customer-owned renewable resources not able to be included in other on-site policies like net-metering and partial requirements tariffs) should be treated like IPP-owned resources in all respects.

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?

If a VRET customer's on-site resource qualifies for the Net Metering program and the customer wishes to include it in the net metering program, then the customer should be able to continue to use the Net Metering program. If the on-site renewable resource does not qualify for the Net Metering program—for instance, because it exceeds the 2 MW project cap—then it should be eligible to be part of the customer's VRET supply under a b/x-type model.

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

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?

The answer to this question depends on the VRET model. In general, any model would have to examine and solve for three elements: (1) paying for system resources a VRET customer is not using any more (but might use in the future); (2) paying for system resources a VRET customer is still using; and (3) providing for intra-hour balancing services for variable renewable energy generation.

First, if the VRET customers were actually "leaving the cost-of-service system" as with Direct Access, then the first question would be how to address capacity already acquired to serve the customers, until that cost can be absorbed by other system load needs, as well as the utility's need to plan for the customers' possible return to the system. However, a VRET model likely would not involve customers leaving the system in such a comprehensive manner as Direct Access. Many VRET examples to date involve the participating customers continuing to use and pay for the elements of the cost-of-service system.

For a VRET model in which the participating customers are bringing renewable energy to the system but still relying on the utility to meet their loads, then the goal is to find a VRET rate design that balances administrative feasibility and acknowledgment of the VRET resource's energy value and system capacity contribution, but also captures the cost of the system elements still being used. A starting point may be to create an energy credit but leave the VRET customer's demand charge in place, with a discount for the capacity contributed by the VRET resource. For variable energy generation, the rate would need to address the incremental intrahour flexibility required to balance the VRET resource and what ancillary services the resource may be supplying to the utility system.

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)?

Risk placement can be managed through VRET design. The first place to start is to expect customers to be able to make 10-15 year commitments (with flexibility to shift the load to another location or customer if necessary), and developers to be able manage deals with those time horizons. With a b/x-type model, contract and tariff terms can be designed to allow customers and developers to negotiate around the risk of default, without any material impact to the utility.

In an aggregated c/d-type model, there is more utility involvement—but risk can still be minimized and managed appropriately. One California utility is proposing a green tariff product for smaller customers in which customers subscribe based on the cost of the utility's last RPS acquisition; the utility supplies the customers with surplus RPS resource for a transition period (this would be more complicated in Oregon, but non-utility existing resources or RECs could be an alternative); and then procures new renewable resources for the subscribers using power purchase agreements, crediting customers bill for avoided generation including peak contribution.[1]

[1] See Pacific Gas & Electric website: http://www.pge.com/myhome/environment/pge/greenoption/faq/

Of course, the risk of customer departure still exists despite the requirement that customers commit to the green tariff for a period of time, but with an aggregated pool of customers risk can be minimized. In Oregon's green power programs, aggregate participation has been growing in the aggregate for many years despite changes in individual customers; for larger customers, that profile is different, but a buying pool will still minimize risk. In any case, the 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. That is likely to be a relatively small cost difference (or maybe even a cost savings).

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?

See answer to IV.1, above. In the most common models for green tariffs, the participating customers are replacing primarily their energy charge with supply from renewable energy projects. They are still paying a significant portion of their demand charge.

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)?

If a VRET design involved customers completely leaving the cost-of-service system in a manner equivalent to Direct Access, then it is unlikely that they would be part of "total retail electric sales" and it is highly likely that the customers would pay equivalent transition charges. These are designed to account for all system costs, including RPS compliance.

More likely, VRET customers would have more ongoing connection to the cost-of-service system and would be part of total retail electric sales. There are a variety of ways that VRET could be designed to allow customers to elect to continue to receive supply from and participate in paying for utility RPS procurement, depending on the customer's individual claiming requirements. This is an evolving area that requires further exploration, with the goal to facilitate new models while maintaining the integrity of the existing system for accounting for and claiming environmental attributes.

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?

Utility capital investments certainly complicate VRET model design, both in terms of competitiveness considerations and risk to non-participants. If utility ownership is to be considered, the assumption in this question—that VRET customers, not other customers, be responsible for paying the utility's cost of capital, at least for above-market resources—seems appropriate.

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?

See California utility example in IV.2, above. Waiting for customer commitments before committing to new resources, and serving customers with a transitional renewable option until new resources come online, seems to be the best approach.

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

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?

For c/d-type models in which the utility procures renewable energy supply for an aggregated customer portfolio, then fair, open competitive procurement should be required as the only reasonable way to ensure that participating customers are getting the most cost-competitive renewable energy deals. Whether an independent evaluator is used should depend on how large the procurement is, whether the utility is permitted to bid, and other considerations. Customer representatives from the pool electing VRET supply may also wish to have a role in procurement.

For b/x-type models, finding competitively-priced supply can be left to the customer. Presumably, customers electing this path have preferences, expertise or market connections to find the renewable energy supply they desire. More attention may need to be given to creating a level playing field in this type of model if utilities with superior customer access are allowed to supply customers with utility-owned (or utility-subsidiary-owned) renewable energy projects.

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?

This detailed question should be tackled if a c/d-type VRET model is proposed, but the PUC's existing processes should be a starting point for large procurements if utility ownership of resources is allowed.

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?

If Model 2 is defined as *only* offering regulated utility owned resources, then it leaves little room for competitive procurement—and is a bad idea.

With respect to Model 4, we offer the same answer as above: For b/x-type models, finding competitively-priced supply can be left to the customer, including deal structures that involve customer ownership.

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?

The starting point should be the Oregon PUC's existing competitive procurement processes. These cumbersome processes have not always been perceived as satisfactory in overcoming utility ownership bias, so some experimentation could be warranted.

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?

For aggregated, c/d-type products, the key piece of oversight would be to ensure that the most cost-competitive eligible renewables that match customer resource preferences are being procured and that customers are able to make the claims they anticipated. Green-e certification of the program could be considered, or a customer advisory group.

For customer-directed, b/x-type products, customers may choose to take advantage of a new Green-e certification offering—Green-e Direct.[2] Green-e Direct helps participants purchasing renewable energy directly ensure their chain of custody and claims are valid.

[2] "The Green-e Direct option offers third-party oversight over chain of custody of renewable electricity or carbon offsets, from generation to retirement. Green-e Direct also offers participants guidance with renewable energy or carbon offset claims, assurance that the underlying environmental commodities (RECs and/or carbon offsets)

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)?

Power mix disclosures. Renewable energy paid for and supplied to particular customers should be represented as null power or brown power assigned the system mix in supply disclosures to cost-of-service customers. Many VRET participants will expect to be able to make claims and report purchases in greenhouse gas accounting. Representing their renewable electricity as renewable supply to all customers would result in double claims that impair their claim and reporting ability. (Generation or capacity reporting can be different, if presented clearly.[3])

Partial loads/RPS. 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 an 100-percent renewable energy supply, if the utility-supplied RPS renewables meet the customer's quality and recency requirements (or Green-e's or another certification standard's – like carbon accounting – that the customer may use) and the customer adds voluntary renewables on top. This is an emerging area and the specific rules for making those claims need to be explored in future phases.

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

This Issues List is a detailed and thoughtful review of the issues that any VRET proposal should be expected to consider. It may not be completely exhaustive (despite being completely exhausting!) and other questions may certainly come up in approval or disapproval of a particular proposal.

At this stage, though, Renewable NW goes back to its introductory questions. Can a VRET promote more renewable energy supply that benefits our economy, communities, and electricity system? Can a VRET coexist with Direct Access? Can a VRET appropriately balance

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will not be double-claimed, and confirmation the electricity or carbon offsets meets the environmental quality outlined in the Green-e Standards.

You rely on Green-e for your renewable energy certificate (REC), utility green pricing, competitive electricity, and carbon offset purchasing. Now you can get the same Green-e guarantees for direct renewable energy or carbon offset procurement."

[3] See Center for Resource Solutions, *Explanation of Green-e Energy Double-Claims Policy*, ver. 1 (June 23, 2014), at p. 4-5, available at http://www.resource-solutions.org/pub_pdfs/Explanation%20of%20Green-e%20Energy%20Double%20Claims%20Policy.pdf.

the interests of participating and non-participating customers? Can a VRET be structured to give customers access to the most competitively priced renewables on the market? Our answer to all of these questions is “most likely, yes.” We encourage the Commission to direct parties to make a specific proposal for a minimum 150 MW pilot program before June 2015 to move the process forward to consider whether a fleshed-out VRET proposal can indeed answer all of these questions with a definitive yes.

Study of Potential Model VRETs

8/15/14

Basic Structure				Statutory Considerations					Potential Conditions
Resource Owner	**Utility Role**	**Relationships**	**Notes/Comments**	**Further Dev of Significant RE**	**Effect on Dev of Competitive Retail Markets**	**Impacts on Non-Participating Customers**	**Competitive Procurement Process**	**Other Considerations**	**to mitigate issues or cons in the statutory considerations (e.g. VRET cap, transition adjustment charges)**
Third Party - Existing Direct Access Comparison to Potential VRET Models	**Existing Direct Access-** "Direct access" means the ability of a retail electricity consumer to purchase electricity and certain ancillary services directly from an entity other than the distribution utility. (860-038-0005(13))	*ESS contracts with non-residential customer to sell electricity services. *ESS schedules energy to utility, which delivers the energy to the customer through the distribution system. *ESS could provide back-up/supplemental (firming/shaping) services, but 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.	Staff added this row at the suggestion of several parties as a backdrop to the VRET models evaluation to provide a comparison between potential VRET models and the existing direct access model.	VRET models can access incremental demand beyond what can be met by renewable energy supply through Direct Access.	*DA should be subject to the same treatment as the VRET in terms of elements for which there is no reason for difference. *VRET should be designed to be complementary to DA.	If leaving the cost of service systrem, there is a requirement to pay the utility transition charges to cover the capacity that has already been acquired on their behalf.	Finding competitively-priced supply can be left to the customer, as by electing for this path they presumably have the requisite expertise and risk tolerance.		
(1.) Third Party (IPP, ESS)	**(1.b/x)** Third party owned renewable resource. Regulated Utility facilitates between a 3rd party and customer(s).	*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.	This model is generally described in the Rocky Mountain Power filing in Utah (Docket 14-035-T02), but staff removed the "second contract" language because it may not be legal in Oregon. Instead, staff replaced "second contract" with tariff. Also, staff added elements of RNW's (1.x) model without the specifics of the RFP (which will be examined in the statutory considerations and potential conditions sections of the study).	*Enables the most motivated customers to apply energy expertise or strong preferences to particular projects, therefore likely to best promote initial growth.	*Would have the positive effect of encouraging customers to think differently abould supply choices, including DA as an option. *Ensuring pricing confidentiality would be essential to ensuring a competitive retail market, if utilities are permitted to supply RE.	Contract and tariff terms could be designed to allow customers and developers to negotiate around the risk of default, without any material impact to the utlity.	Finding competitively-priced supply can be left to the customer, as by electing for this path they presumably have the requistie expertise or preferences.	Matching on site load should not be a requirement for a VRET; bill credits are more straightforward and different from DA.	
	(1.c/d) Third party owned renewable resource. Regulated utility or third party aggregator matches VRET loads with aggregate VRET RE generators to mitigate issues of timing and risk.	*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 RE 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 could match VRET load(s) with aggregate VRET RE generators to mitigate issues of timing and risk.	Combined 1(c) and 1(d) to create this row 1(c/d). Issues of timing and risk depending on when and how aggregation occurs. Added option for third party aggregator (not just utility) to aggregate load or supply.	*Most scalable to attract customers with less energy expertise or less specific resource preferences. *Can offer economies of scale to reduce costs.	This model need not impair a competitive retail market as customers likely to buy into an aggregated model are unlikey to have considered DA an attractive option in the first place.	*Could be better integrated with supply planning to reduce impacts to non-participants at lower cost.	*Competitive procurement would be critical here to ensure cost-competitive supply that generally matches customer resource preferences.		
(2.) Regulated Utility	**(2)** 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.	General concerns in comments about ability of regulated utility to prevent cost-shifting and effects on competive market - which will be explored through consideration of the statutory factors.						
	(2.c/d) 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)).	*Similar to relationships in the aggregation-related 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 RE generators and purchase output through fixed price, long term contracts; the regulated utility could then offer that output to customers through a "subscription" process.	General concerns in comments about ability of regulated utility to prevent cost-shifting and effects on competive market - which will be explored through consideration of the statutory factors.	*Most scalable to attract customers with less energy expertise or less specific resource preferences. *Can offer economies of scale to reduce costs.	*Robust protections would be required to mitigate the effects of utility ownership bias.	*IRP planning could assess the increased costs of acquiring extra RE, both to ensure non-participating customer protection and to be able to offer it to VRET customers at a known cost. *While the risk of customer departure exists in an aggregated model, the potential risk would be smaller. *If the utiltiy owns the resource, the VRET customer should be responsible for paying the utility's cost of capital, at least for above market resources.	Fair, open competitive procurement should be required as the only reasonable way to ensure participating customers are getting the most cost-competitive RE deals. The OPUC's existing competitive procurement process shoulbd be the starting point.	*Customers need to be able to make the clean energy claims they anticipated—Green-e certification should be considered.	
(4.) Customer Owned	**(4.a/x)** Customer owned renewable resource. Regulated Utility role depends on the customer's specific load and resource. Could involve distribution and back/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 - 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.	General concerns in comments about interaction with net metering and whether customer-owned resources should be treated like third-party IPPs. Continued open questions and potential confusion about on-site or off-site customer owned resources. Staff added elements of RNW's (1.x) model without the specifics of the RFP (which will be examined in the statutory considerations and potential conditions sections of the study).	Allows development of renewable energy in addition to onsite systems which fall in the net metering program.				Offsite customer owned resource (and on-site not able to be included in existing policies like NM and partial requirement tariffs) should be treated like an IPP in all respects.	