OREGON PUBLIC UTILITY COMMISSION

Docket No. UM-1690 Voluntary Renewable Energy Tariffs

COMMENTS OF Letha Tawney, Sr. Associate at World Resources Institute

I respectfully submit comments in response to the draft VRET Models Table circulated by the Commission Staff on December 11, 2014. As requested by the Staff, I have populated the final models table with comments on individual elements of that table and answered the questions posed in the final Issues List. The populated table and issues list are attached as an appendix to these overview comments.

As Phase 1 of this VRET process moves forward with the anticipated staff report, I encourage the Public Utility Commission to determine it is reasonable and in the public interest to invite the electric companies to file VRET schedules for evaluation.

Enabling utilities to offer Voluntary Renewable Energy Tariffs ("VRETs") can reasonably be expected to produce substantial public benefits, notably by encouraging the development of renewable energy and attracting large, sophisticated business customers in the technology and other sectors, who are actively seeking out renewable energy supplies and who often have the ability to shift operations, employment, and energy consumption among locations readily. By adding, or retaining, a significant customer base in the Oregon electricity system, VRETs can also strengthen the offering utilities and potentially independent generators financially, to the benefit of non-VRET customers as well.

Since discussions about VRET options emerged in Oregon, World Resources Institute had documented five other VRET like products across the country proposed or finalized. Transactions are beginning to emerge between customers, utilities and independent power producers. These are documented in the attached appendix. – Green Tariff Table. Additionally, utilities, legislators, and regulators from other states have approached World Resources Institute and signatories to the Corporate Renewable Energy Buyers' Principles[1] to discuss how they might replicate VRET like options to ease access to renewable energy and attract new companies to their jurisdictions. While still a new approach, evidence and design options are beginning to emerge.

Properly structured, Voluntary Renewable Energy Tariffs can provide significant benefits, in among other things, promoting the development of renewable energy resources, encouraging economic development.

Respectfully submitted,
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[1] See Corporate Renewable Energy Buyers' Principles at http://www.wri.org/publication/corporate-renewable-energy-buyers-principles.

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.						
(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).	Whether the utility's ability to offer the purchased power on a dedicated basis under a VRET encourages or discourage development of RE primarily hinges on whether this approach offers simpler access for customers with lower transaction costs than other options. Insofar as the transaction would increase throughput over the wires, the utility has incentive to accommodate this type of transaction, which could only encourage RE.	Whatever incentives the utility has to sell its own brown or green power would not be materially changed by allowing its participation in this type of transaction to be pursuant to a VRET.	The ability of a utility to offer this model of a VRET has no effect on extent of stranded costs caused by this type of buy-sell transaction, and no effect on ability to shift such costs to non-participating customers. Risk that VRET customer default impacts non-participating customers can be addressed through contract design and refusal to rate-base stranded VRET resources that do not meet standard criteria for prudence.	It would be inappropriate to require customers to engage in competitive procurement for this type of transaction. Of course, they might choose to do so. But, they know what is best method of acquisition for them.		If the utility's contract with the IPP terminates if customer defaults. So, the risk of customer default is borne by the IPP, not the utility.
	(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.	Aggregation of load can bring efficiencies, in the form, for example, of greatly reduced transaction costs, complementary load profiles that encourage better location and placement of RE, RE facilities larger than they might otherwise be (realizing scale economies), and eliminating risk to IPP of reliance on a single customer's continued business operations and creditworthiness. The opportunity to obtain RE in a simpler way for multiple meters could encourage customers to participate who might not otherwise pursue RE. The opportunity to offer a VRET to aggregated load could therefore encourage RE.	Aggregation of load by utility arguably might preempt bilateral opportunities of IPPs selling RE. But this preemption would be the result of efficiencies, not unfair advantage. It would occur only if the customers participating in the aggregated load view aggregation as preferable to bilateral arrangement with an IPP.	Aggregation of load might increase the size of stranded utility generation costs by driving expansion of RE. Even if that is the case, there would not be an increase in the ability to shift those costs to non-participating customers since the bars on doing so are already established in regulations. Aggregation of load should not present any special difficulties in identifying costs attributable to the VRET customers.	The utility's acquisition of power to serve aggregated load should be through competitive procurement, that could include utility affiliates and even customers owned facilities. Doing so maximizes price discovery and removes any issue as to whether the utility's incentive is to bargain for the best price (which might otherwise be in question if the utility is not to be allowed any mark-up).	Consideration should be given as to whether there are any issues relating to the need to prescribe procedures and criteria to determine opportunity of customers to participate in a given aggregation of load.	If preemption of IPPs is viewed as a serious problem, it could be cured by requiring the utility to disclose identities of the facilities to be aggregated, and allowing reasonable opportunity for IPPs to seek bilateral arrangements with those facilities. A steadily growing cap on VRET subscriptions, while primarily intended to avoid cost-shifting existing assets to non-participating customers would hve the additional advantage of limiting the slightly increased risk of stranded VRET resources the aggregate model could create.
(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.		If and to the extent that VRETs would lead to utility intent to increase owned RE, VRETs might increase the incentive to favor the utility's own RE. This might discourage RE development if utilities have the ability to act on those increased incentives. Does the utility have that ability, so that utility RE will prevail over equally or more efficient IPP RE? The answer depends on efficacy of existing regulations governing interconnection, access to T&D, and unbundling of costs. A VRET does not expand any deficiencies in those regulations.	The identification of costs caused by the dedicated resource owned by the utility should not pose unique problems, particularly if the resource is bid into a competitive procurement. Allocation of costs that are joint and common with non-participating customers should be by standard methods for allocation among customer classes.	This becomes an issue only if other generators have disadvatanged access to the customers, i.e. model 1.b/x is not allowed while this model is allowed. If both are allowed, it would be inappropriate to require customers to engage in competitive procurement for this type of transaction. Of course, they might choose to do so. But, they know what is best method of acquisition for them.		Other jurisdictions have mitigated the competitive risk in this approach by allowing large customers to bring PPAs to the utility, rather than relying solely on the utility procuring the resources for the customers. Essentially, model 2 should not be enabled without model 1.b/x being also enabled.

	(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 competitive market - which will be explored through consideration of the statutory factors.	Utilities have stated in IRPs that, on the basis of cost projections, they do not wish to exceed their RPS obligations. A well designed VRET in general could expand RE beyond this current ceiling - regardless of the generation ownership model.	see directly above	see directly above	The utility's acquisition of power to serve aggregated load should be through competitive procurement, that could include utility affiliates and even customers owned facilities. Doing so maximizes price discovery and removes any issue as to whether the utility's incentive is to bargain for the best price (which might otherwise be in question if the utility is not to be allowed any mark-up).		The risk that the incentives created by the potential for utility ownership of the RE facility will lead them to unfairly block truly lower cost, more efficient project owned by customers or other parties can be mitigated by a) benefit by offering a least cost aggregated product and b) allowing other aggregators or suppliers market to the customers and require the utility to allow those transactions. That is, full competitive procurement is not necessary if this model is done only in conjunction wtih the other ownership models.
(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).		The customer's desire to own the RE facility could concievableuy displace some other investor or owner/operator in the renewable energy marketplace. However, the increased investment in the sector that this flexiblity would allow would improve the overall health and sustainability of the clean energy supply chain with benefits to all players in that supply chain.	The ability of a utility to faciltiate this model of a VRET has no effect on extent of stranded costs caused by this type of buy-sell transaction, and no effect on ability to shift such costs to non-participating customers.	It would be inappropriate to require customers to engage in competitive procurement for this type of transaction.		

Emerging Green Tariffs in U.S. Regulated Electricity Markets

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Introduction

Electricity customers – from residential to large industrials – want to go above and beyond the renewable energy currently offered through the electricity grid. Apart from environmental concerns and reputational advantages, renewable energy allows them to reduce their electricity bills and protect themselves against volatile fossil fuel based power prices. The Corporate Renewable Energy Buyers' Principles, representing more than 10 million megawatt-hours (MWh) of demand for renewable energy per year by 2020, are just one example of this emerging trend to buy more renewable energy. As the Principles make clear, these customers want more than just the Renewable Energy Certifications (RECs) that allow them to credibly claim 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 only provide RECs at a premium price. By offering only 'unbundled' RECs, separate from energy, these programs do not usually provide a fixed cost of energy as a hedge against volatile fossil fuel prices. An emerging option in markets where there is no functional retail electricity choice to access fixed price renewable energy, is green tariffs or riders. These rates, 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 economic value to customers than unbundled RECs alone.

Through green tariffs, traditional utilities may be able to offer similar financial features to the renewable energy offerings in competitive markets or by third-party financed 'behind-the-meter' renewable energy. However, they may also prove to provide greater flexibility and lower transaction costs, given their 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 a [fair and equitable] price, 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. Though, there may be system-wide benefits that justify some shared cost, depending 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 and 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 SB43—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 excluding it from this table, though there are perhaps lessons to be learned from it and community choice aggregation in general for larger customers.

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

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.

[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.

Utility/State	IOU Proposal – due Spring 2015	Rocky Mountain Power - Utah	NVEnergy - 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
Pilot Size/ Period	- Not defined yet, unknown if a limit will be set	- Capped at 300 MW total peak delivered to all customers - PUC can increase without returning to the legislature	- Capped at 250,000 MWh though NVEnergy can choose not to count special contracts against the total	- Capped at 1,000,000 MWh or 3 year enrollment period, whichever occurs first	- Capped at 240,000 MWh, 100 customers, or 3 year enrollment period, whichever occurs first

Utility/State	IOU Proposal – due Spring 2015	Rocky Mountain Power - Utah	NVEnergy - Nevada	Duke Energy - North Carolina	Dominion Power - Virginia
Tariff/ Contract Structure	- Utility signs fixed price, 15 year contract with RE generators - Customers subscribe to the pool of RE resources for 10 years, with an option to extend for the last 5 years in year 7	- RE facility is selected by the customer, not RMP – 2 contracts: 1) between RMP and the customer and 2) between RMP and the renewable energy facility - Same pricing and duration for both contracts - RMP takes ownership of the electricity from renewable energy facility	- 2 options for commercial customers—1) to contract directly with NVEnergy for 50 or 100% of monthly electricity usage or 2) Customer and NVEnergy 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

Utility/State	IOU Proposal – due Spring 2015	Rocky Mountain Power - Utah	NVEnergy - Nevada	Duke Energy - North Carolina	Dominion Power - Virginia
Customer Cost Structure	- Energy component in standard schedule is replaced by the RE contract with the utility, but other tariff elements and rates remain the same - Declining penalty for early exit	- RE energy and power, and supplementary services are balanced at every 15 minute interval for every meter and charged at rates specific to this tariff - 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

Utility/State	IOU Proposal – due Spring 2015	Rocky Mountain Power - Utah	NVEnergy - Nevada	Duke Energy - North Carolina	Dominion Power - Virginia
Admin. Fee	- Proposed to be per customer - not per meter	- Proposed $150 per account (meter) per month and $110 per generator per month	- 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
Hedge Value of the RE	- Customers shielded from fuel price surcharge and decoupling charges embedded in the energy charges of the tariff - If the RE price in the PPA falls below the utility mix energy price, the benefits accrue to the customer in lower rates	- Replaces existing schedules so theoretically could deliver lower cost than standard retail rates - Reduced exposure to fuel price volatility to the degree energy is procured from RE facility	- Unclear in the filing whether the NGR rider can ever be negative and appear as a bill credit against the otherwise applicable rate schedules	- 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 customer is exempted from the fuel surcharge rider

Utility/State	IOU Proposal – due Spring 2015	Rocky Mountain Power - Utah	NVEnergy - Nevada	Duke Energy - North Carolina	Dominion Power - Virginia
Customer Right to Veto Offer/ Contract	- Customers can choose not to subscribe to the offering, but do not engage in the PPA negotiations	- Customer brings the PPA to RMP & leads on the PPA negotiation	- Not explicit in the filing, but the customer can refuse to enter the special contract with NVEnergy	- Duke will negotiate with the facility, but customer has right to review the offer and the estimated bill credit and not go forward	- Dominion negotiates with the facility and customer; Customer has veto right with no impact on Dominion
Bundled RECs Management	- Retired on behalf of the customers	- REC contract is directly between renewable energy facility and customer	- RECs will be retired against the RPS requirement for the customers' 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 (e.g. open and close stores, offices, etc.)	- RE facility can service multiple customers or customer meters but fees are per meter	- 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

Utility/State	IOU Proposal – due Spring 2015	Rocky Mountain Power - Utah	NVEnergy - Nevada	Duke Energy - North Carolina	Dominion Power - Virginia
Contract Time Commitment	- Ten years, with an option to extend for additional 5; provide notice in year 7 if they will execute the 5 year extension	- Negotiated—identical for both contracts	- Negotiated but not less than 2 years	- Negotiated—3-15 years	- Determined by the REPSA and customer requirements, 10 years suggested
Customer Limitations / Eligibility	- Commercial, non-residential meters of any size	- Customers must contract for 2MW or more - Only customers otherwise on schedules 6, 8, or 9	- N. Nevada: GS-2 meters or larger, demand between 50 and 500 kW or monthly usage larger than 10,000 kWh - S. Nevada: LGS-1 meters & larger , monthly usage larger than 3,500 kWh - Customers can subscribe a portion or all of their energy consumption	- New loads of at least 1 MW since July 30, 2012 - Non-residential customers, OPT-G, OPT-H, OPT-I tariffs only	- Non-residential, commercial customers on GS-3 and GS-4 tariffs - Demand greater than 500 kW - Individual purchase of RE from 1 - 24MWh per year

Utility/State	IOU Proposal – due Spring 2015	Rocky Mountain Power - Utah	NVEnergy - Nevada	Duke Energy - North Carolina	Dominion Power - Virginia
Aggregation of Customer Facility Demand	- Aggregation of meters is expected to be allowed for administrative charges and contracting	- 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 of Net Metering of Onsite Resources	- So far, unclear	- Net metering of the electricity purchased from the facility by the customers is not allowed.	- NVEnergy is not prohibited from also accepting net metered energy from the customer	- No limitations defined in the filing	- Customers cannot participate in this tariff and net meter
RE Facility Limitations / Eligibility	- Not defined yet, but first proposed project is a local IPP facility	- 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 NVEnergy - 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 implies North Carolina facilities	- RE facilities within the PJM Interconnection

Utility/State	IOU Proposal – due Spring 2015	Rocky Mountain Power - Utah	NVEnergy - Nevada	Duke Energy - North Carolina	Dominion Power - Virginia
Commercial Risk Management	- If it is undersubscribed, the excess energy will be dispatched into the larger system at the PURPA rate and the RECs used in the green power pricing program to recover the difference between the PURPA rate and the PPA.	- Customers 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, NVEnergy 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	- Ongoing into 2015, no deadline for PUC decision - Directing legislation, SB12 was effective 5/8/12	- Approved 9/9/13; - NVEnergy applied to extend the special contraction option of the rider to S. Nevada via docket 14-0631, the PUC approved 11/13/14	- Approved 12/19/13	- Approved 12/16/13
RE Deals Signed	- MOUs signed, pending PUC process	- MOUs signed, pending final PUC decision	- Apple Fort Churchill project approved in docket 13-07005	- Customers have applied and are in negotiations	- Dominion reports the rider is unused to date.

Utility/State	IOU Proposal – due Spring 2015	Rocky Mountain Power - Utah	NVEnergy - Nevada	Duke Energy - North Carolina	Dominion Power - Virginia
Docket Information	N/A	Docket 14-035-T02, implementing SB12	Docket 12-11023 (N. Nevada) and 14-06031 (S. Nevada)	Docket E-7, Sub 1043	Case PUE-2012-00142

Glossary of Terms

GS: General service
IOU: Investor-owned utility
NGR tariff/rate: Name given to NVEnergy's green tariff and rider rate
OARS: Otherwise applicable rate schedule for customers served by NVEnergy
OPT tariff: Duke "Optional Power Service, Time of Use" tariff structure
PJM: 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 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
RMP: Rocky mountain power
RPS: Renewable Power Standard, i.e., state-law requirements as to the amount of energy sold by a regulated utility that must come from specified types of RE generation.

Implementation of HB 4126 – Voluntary Renewable Energy Tariffs (VRETs)
REVISED by PUC Staff after 8/29/2014 Comments
11/07/2014 Issues List

The issues list below is categorized by general issues and issues relevant to the five statutory considerations listed in HB 4126 Section 3(3). Within each category of issues, there may be specific questions related to VRET Models discussed during UM 1690 workshops. Please refer to the VRET Models Summary Table for a description of each Model.

Letha Tawney's responses can be found after each question, marked in italics.

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?

   The 19 signatories of the Corporate Renewable Energy Buyers' Principles[1] 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 reasonably close to their operations, access to bundled Renewable Energy Credits (RECs), simplified transactions, and increased access to third-party financing for projects. These are crucial design elements, however customers have a wide variety of load profiles and internal capacity to procure energy. Thus, allowing more than one type of VRET design will help to satisfy diverse customer demands and maximize the opportunity to further development of renewable energy.

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?

   Much as utilities today must consider direct access load, energy efficiency trends, and self-generation, they should consider VRET load in IRP planning. In particular, VRET load projections could support renewables-centric procurement when additional capacity requirements are identified in the IRP process.

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

      There is demand for RE from large individual loads, large aggregate loads and smaller businesses. While a VRET pilot may start with only one subset of customers, maximizing the opportunity to drive renewable energy development argues for allowing utilities to steadily expand the VRET availability over time, particularly as new capacity needs are identified in the IRP process.

   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)?

      Other jurisdictions have capped their VRET-type programs, though Nevada and Utah have chosen soft caps that can be raised by the utilities or the PUC without authorizing a new phase of the program.[2] In Oregon, caps could be set by utility based on, for example, short-term market transactions in the prior year or anticipated capacity shortfalls identified in the IRP process. This sort of approach would limit the risk of impacts on non-participating customers but

[1] See Corporate Renewable Energy Buyers' Principles at http://www.wri.org/publication/corporate-renewable-energy-buyers-principles. Signatories include:3M, Bloomberg, Adobe, Sprint, eBay, Volvo, Cisco, Facebook, Walmart, HP, Johnson & Johnson, Proctor and Gamble, Novo Nordisk, Intel, EMC, Novelis, Mars, GM and REI. Together, these businesses represent more than 10 million MWh of annual demand for renewable energy by 2020 across the United States.

[2] See WRI's Emerging Green Tariffs Table, submitted as an appendix to these comments for more details on VRET-like proposals emerging around the United States.

could allow the program to grow in a measured way over time. This approach 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.

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?

   Other jurisdictions and proposals are enabling site aggregation including two proposals allowing aggregation of small commercial meters. Flexibility is key to meeting a wide range of customer needs around renewable energy and maximizing the opportunity to drive further development of significant renewable energy. There is no reason to presume aggregation of load would increase the risk of negative impacts and could reduce impacts by diversifying the VRET load, so the default should be to enable flexibility.

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?

   Aggregation of resources would provide more flexibility for customers and could offer efficiencies but should be handled in such a way that competition produces a least cost offer to customers in order to maximize the opportunities presented by the VRET to drive renewable energy development.

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

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)?

   There have been a variety of approaches. Nevada has only allowed renewable resources as defined their RPS rules. North Carolina has defined a vintage year, 2007, as the definition of new. Customers have been clear in their desire for additionality, regional proximity, and RECs credibility. Setting out constraints on the utilities seems unnecessary if customers can choose between generation options offered by utilities and others.

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)?

Utah and others have set geographic bounds on the renewable resources that can be offered, though other jurisdictions have not. There are not large price differentials in renewable energy resources between states in the northwest region – as there are perhaps in regions bordering the Midwest – so flexibility of choices should be given priority over further constraints in order to maximize further development of resources.

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

   In other jurisdictions the keys to success are only just emerging now. However, emphasizing ease of use, low transaction costs, and maximizing customer choice are reported to be crucial to getting transactions completed.

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

As discussed in my July 25, 2014 comments, it seems most useful to consider whether and the extent to which implementation of a VRET would increase the incentives or ability of a utility to behave anticompetitively, in comparison to the case in which no VRET could be offered. In other words, would the VRET make uncompetitive outcomes more likely, when compared with the "no-VRET" case?

Keeping this principle in mind as the VRET is designed can avoid impacts on competitive markets. If, and to the extent that, there are deemed to be flaws in current regulations applicable to retail competition, these flaws can and should be addressed separately, in proceedings relating to the overall 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.

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

   The 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 though some parties clearly find them.

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?

   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.

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]**:
   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?
   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?
   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)?
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)?

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?
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?
   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?
   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])?
   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?
   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?

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

As discussed above, setting a cap for VRET subscriptions by utility that allows for measured growth and is tied perhaps 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.

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?
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)?

   Different models have different remedies – most to date put the risk entirely on the customers and cancel any obligation for the utility with the generator if the customer defaults. But at least two propose 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 born by their unbundled RECs green power buying program. The Commission and Utilities could consider these and other options to allocate the risk appropriately.

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?
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)?

VRET customers should continue to pay for RPS compliance, particularly because as a utility offered product, these customers would take credit for the RPS RECs retired on behalf of their use of the system. This approach complies with guidance for green house gas accounting and green claims as we currently understand them.

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?

   VRETs are fundamentally a market priced products 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.

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?

   Another utility in another state is considering this issue as they design their VRET-like product. They are putting the risk of under-subscription into their voluntary, unbundled RECs green power pool, which is large enough that the impact on customers would be negligible compared to RECs price volatility. More generally though, we see the development of memorandums of understanding as different market participants line up the many pieces necessary before moving to 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 is truly necessary to find a least cost product offering.

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?

   A range of approaches is emerging – where the utility finds the resource, where the customer brings the resource desired to the utility, where the utility owns the resource. Since this is fundamentally a market-price product rather than a cost of service product, market participants should seek to provide the lowest cost products. This can be maximized by ensuring that if customers find lower cost offers than the utility provides, the utility cannot block or discriminate against those opportunities. This is perhaps hardest to achieve in a model where the utility aggregates resources, but if other market participants can offer alternatives to customers, this risk is minimized.

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?
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?
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?

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?
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)?

   Corporate greenhouse gas accounting guidance[3] and Federal Trade Commission rules set out what can be credibly claimed. By buying a utility offered product the company can claim the RPS proportion in its consumed electricity. It would then also claim the energy it purchases from the utility via RECs that were either transferred to it or retired for it in a credible tracking system. The utility could NOT claim the RECs retired on behalf of the customer for the RPS or any other purpose. However, most existing VRET-like rates have not been explicit about how to handle this issue.

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

   As noted in my comments July 25, 2017 comments in this proceeding, large, sophisticated, and energy-intensive businesses are increasingly drawn to renewable generation as the preferred source of power for their operations. They perceive advantages in avoiding fuel-price volatility and in having access to renewable energy from projects near their facilities. They also emphasize the importance of having choice among suppliers and products to meet their business goals. Such businesses, particularly in the technology sector, have the ability to shift operations—and thus output and employment—among existing locations quickly and with relative ease; data storage and processing operations would be one such example. Being able to offer renewable energy under VRETs that reflect actual costs of generation, transmission, and distribution can significantly bolster Oregon utilities, and the communities they serve, in their ability to attract and retain such businesses, to the benefit of the state's economy as a whole.

   It should also be noted that, by enabling Oregon utilities to compete for a sizable and growing customer base, the authorization of VRETs have the potential to strengthen those utilities financially, with resulting benefits -- such as lower costs of capital -- to their traditional, non-VRET customer base as well. Expanding the potential market for IPPs through competitive procurement and simplified transactions similarly could strengthen their financial base. Conversely, the loss of large existing or potential customers, possibly leading to underutilized facilities and stranded costs, will adversely affect those utilities and their remaining customers.

[3] See Greenhouse Gas Accounting Scope 2 Guidance on consumed electricity at http://www.ghgprotocol.org/scope_2_guidance.