BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the	)	
	)	**Docket No. UE-100849**
	)	
Inquiry on Regulatory Treatment for	)	
Renewable Energy Resources	)	
	)	**Joint Comments of Renewable**
	)	**Northwest Project, NW Energy**
	)	**Coalition, Climate Solutions,**
	)	**Cascade Chapter of the Sierra**
	)	**Club, and Washington**
	)	**Environmental Council**
	)	

The Renewable Northwest Project ("RNP"), the NW Energy Coalition ("Coalition"), Climate Solutions, Cascade Chapter of the Sierra Club, and Washington Environmental Council appreciate the opportunity to provide comments in response to the Commission's Consolidated List of Issues. We strongly support the Commission's intention to keep this proceeding focused on regulatory issues within the Commission's direct control. As the Commission reflects upon the comments and replies submitted by the various parties, we once again urge caution in considering any proposals to amend Initiative 937 ("I-937"). The Initiative is in the early stages of implementation and no fatal flaws have been identified. Any potential modifications to I-937 can have ripple effects elsewhere in the law and will engender rigorous debates concerning equitable treatment. We appreciate the note in the consolidated issues list that indicates, "the Commission may opt to simply summarize [such proposals] for the various Legislative committees as well as for other entities considering legislative proposals."[1]

We do offer a few suggestions for regulatory changes that respond to some of the concerns expressed by utilities, that potentially could improve I-937 renewable portfolio standard (RPS) implementation for all parties, and that may promote the greater inclusion of renewables in Washington's power supply. In general, we believe that the existing regulatory structure is sufficiently flexible to accommodate renewable resources. The best approach may be for the Commission to issue a policy statement or similar order resolving some uncertainties surrounding renewables and RPS implementation, without making formal, renewable-specific administrative rules.

[1] Docket No. UE-100849, Consolidated List of Issues, attached to Commission's July 1, 2010 Notice, at p. 4, FN 1.

Consolidated List of Issues

General

1) *Definitions.* What is "*distributed generation"* as applied to solar PV projects? What is an "*integrated cluster of renewable resources*"?

Distributed generation. We have no position as to whether the 5 MW size threshold for distributed generation should be measured in DC (nameplate capacity) or AC (output) for solar PV projects, but we agree that this issue should be clarified in the Commission's rules. Using DC would be administratively simpler, but using AC gives perhaps a more accurate measure of the true "generating capacity" of the PV resource. [2]

Integrated cluster of renewable resources. The Department of Commerce's rules for implementing I-937 include the following definition of distributed generation, intended to clarify what is meant by an "integrated cluster." We support the language in this definition, and recommend the Commission adopt the same or similar language.

> (12) "Distributed generation" means an eligible renewable resource where the facility or any integrated cluster of generating units has a generating capacity of not more than five megawatts. If several five-megawatt or smaller projects are located in the same immediate area but are owned or controlled by different developers, each qualifies as a separate, independent distributed generation project. For the purposes of this rule, an eligible renewable resource or group of similar eligible renewable resources cannot be subdivided into amounts less than five megawatts solely to be considered distributed generation.[3]

This is similar to the language that the Coalition and RNP proposed in the I-937 rulemaking.[4]

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[2] We note that the I-937 rules adopted by the Department of Commerce do not address this issue, and to the best of our knowledge, Commerce does not intend to reopen that rulemaking in the near future. However, the state agency responsible for oversight of WREGIS (as discussed in Question No. 11) will need guidance on which solar PV facilities qualify as eligible renewable resources. The Commission may want to discuss with Commerce and the State Auditor's Office any potential ramifications for the public utilities of adopting an AC versus a DC standard.

[3] WAC 194-37-040(12).

[4] Docket No. 061895. Attachment to comments of RNP, NWEC and NEEC. May 18, 2007. At p. 3. The Coalition and RNP proposed the following language, which parallels the Department of Commerce provision but also included the underlined sentence to provide an affirmative definition of "integrated cluster":

> "An integrated cluster refers to co-located projects owned or controlled by the same developer that feed into the same substation. If several 5 MW or smaller projects are located in the same immediate area but are owned or controlled by different developers, each qualifies as a separate, independent distributed generation project."

Recovery of Costs and Demonstration of Need

2) *Determination of Prudence.* Does the Renewable Portfolio Standard (RPS) in I-937 supersede the "need requirement" used by the Commission for its determination of prudence? Why should the Commission treat the acquisition of a renewable different from the acquisition of a gas-fired plant when considering "need"?

Acquiring renewable generation or renewable energy credits (RECs) sufficient to comply with I-937 is now a requirement of utility resource planning, to be considered on the same plane as reliability requirements and load needs. Utilities now have a new regulatory source of "need," in addition to a load-based "need," to acquire new renewable projects or contracts.[5] The Commission may wish to acknowledge that RPS compliance is an appropriate factor in making reasonable plans and decisions for "needed" resource acquisitions.

The traditional prudence analysis remains an appropriate framework for evaluating renewable resource acquisitions made to comply with I-937. Prudence analysis is a fact-specific, case-by-case inquiry in which the Commission evaluates the reasonableness of company decisions in light of the information available at the time the decisions were made.[6] In prudence review, the "need" to acquire a generating resource or power contract is subject to this broad standard of reasonableness.[7] In the context of a renewable acquisition motivated by the RPS, a utility can show that it made a reasonable projection of how much renewable energy it needed to comply with RPS targets; that it appropriately evaluated the lowest cost mix of resources needed to meet its RPS targets while serving its load; and that it acquired those resources or contracts at a time and in a manner reasonably calculated to minimize cost impacts to ratepayers, if any.

Discretionary decision-making about resource timing and cost is not unique to the RPS. Resources and load rarely match perfectly. A utility may reasonably acquire a resource for which it does not have an immediate need, because the resource is available at a low price relative to other alternatives and meets the company's longer-term generating needs—as occurred with Puget Sound Energy's ("PSE") acquisition of the Mint Farm generating facility.[8] "Early" acquisition relative to RPS target dates can likewise be justified by various factors, including but not limited to: a reasonable assessment of contemporaneous market advantages, the

[5] RPS targets are not the first regulatory contributors to utilities' "need" to acquire power contracts or make capital investments. PURPA requires utilities to acquire power from small renewable projects and other qualifying facilities, and environmental regulations may dictate utilities' capital investments in generating facilities.
[6] *WUTC v. PSE*, Dockets UE-090704 and-090705 (consolidated), Order 11 at page 110.
[7] *Id.*
[8] *Id.* at 109-120.

risk of cost escalation closer to the target date, and the ability to sell power and RECs until the renewable generation is needed for RPS compliance. Similarly, a utility with no present energy needs might reasonably acquire a renewable resource because it needs to diversify its power supply in order to comply with the RPS. This would not alter other elements of the prudence inquiry; the utility would still have to demonstrate, based on contemporaneous records, that it met its RPS need at a low relative cost to ratepayers compared to other options.[9]

In short, adding RPS requirements as a potential source of "need" for additional resource supply does not dramatically change the status quo. Resource acquisition decisions will remain, as they have always been, "complex [decisions that] involve consideration of a host of factors."[10] The Commission should recognize explicitly that meeting RPS targets is a legitimate source of need in the context of prudence review. But traditional prudence review should continue to be used to evaluate particular resource acquisition decisions.

3) *Integration of Renewables*. Will future acquisition of non-renewable resources that support the integration of renewable resources encounter the same demonstration of need issue? Discuss what new "litmus" tests may be necessary to evaluate the prudence of renewable integration generating resources and why the current tests may not be applicable.

Each balancing area has a unique blend of advantages and constraints for integrating renewable power, making a one-size-fits-all litmus test inappropriate. Nonetheless, the Commission should signal that the prudence of acquiring a new generating facility will depend upon whether the utility can demonstrate that it appropriately analyzed its integration needs, exhausted all other reasonably available integration alternatives, and has participated actively in the development of lower-cost, market-based integration methods.

Although integration is a complex, technical subject on which significant analytical differences of opinion exist,[11] it will generally be the case that acquiring generating resources to meet utility demand will be sufficient to provide the needed balancing services.[12] Acquiring resources

[9] *Id.* at 111 (listing factors in prudence review).
[10] *Id.* at 119.
[11] For example, RNP joined with the American Wind Energy Association and the Center for Energy Efficiency and Renewable Technologies in protesting PSE's recent wind integration filing at FERC. The protest argued, in short, that PSE erred in equating the need for balancing services with the need for incremental nameplate generating capacity, overestimated the need for balancing reserves, and inflated the cost of providing balancing services. See Exhibit A (FERC protest).
[12] While PSE's FERC filing for a wind integration tariff is based on the cost of acquiring additional generation capability, the filing suggests that PSE has no plans for actually acquiring additional resources for that purpose.

specifically to provide balancing services has not been necessary to date[13] and is generally not the most cost-effective means of accommodating wind generation even on systems where a significant fraction of the total energy is provided by wind resources. Before any such acquisition can be considered prudent, utilities should be required to demonstrate that they have fully engaged with less costly integration strategies, both near-term and longer-term, and that the new generating resource is consistent with prudent utility practice and resource plans.

The 2007 Northwest Wind Integration Action Plan,[14] in whose development all of the Washington investor owned utilities ("IOUs") participated, provides guidance on how market development can make integration of variable power less costly. The Plan calls for:

- developing more cooperation among regional utilities to share balancing resources and requirements more broadly;
- developing faster and more liquid markets to more efficiently and economically utilize flexibility in existing infrastructure;
- making more low-cost flexibility such as that provided by dispatchable load and hydroelectric resources more broadly available; and
- development and application of new flexibility technologies.[15]

Thanks to the participation of utilities, which we very much appreciate and encourage, development in this direction has already occurred. At present, opportunities for lower cost integration alternatives include:

- Requests for proposals (RFPs) for balancing services from other utilities and balancing area authorities, including combinations of part-year contracts designed to lower costs;
- Participation in intra-hour trading programs, including the Bonneville Power Administration (BPA) intra-hour trading pilot program and other flexible, highly efficient web-based trading systems;[16]
- Coordination among balancing areas, either through pilot programs like ADI (ACE Diversity Interchange[17]) or by direct collaboration with other balancing areas;

[13] The only exception we are aware of is the special case of NorthWestern Energy (NWe) in Montana. NWe meets load primarily with contract purchases that have no within-hour flexibility to provide balancing for either wind or load. NWe is building a gas plant to provide balancing services for both wind and load to displace its dependence on contract purchases of regulating reserve.

[14] Available at: http://www.nwcouncil.org/energy/wind/library/2007-1.pdf.

[15] Adapted from NWIAP overview at http://www.nwcouncil.org/energy/wind/library/2007-1.htm.

[16] In June 2010, the Joint Initiative announced the opportunity to subscribe to I-TAP hub software to facilitate intra-hour trades (http://www.columbiagrid.org/download.cfm?DVID=1766).

[17] ACE Diversity Interchange allows a group of balancing areas with variances in their ACE (area control error) values to link these values with the goal to reduce the group's individual ACE values and resulting regulation. A February 2008 report on the ADI experience of five northwest balancing areas stated that the "effort had not caused

- Promoting and implementing load control programs; and
- Improved forecasting and operating protocols, for utilities that operate wind or solar projects.

At this time, we believe that the above represent opportunities to more economically integrate variable resources. While utilities may prefer to leap to more familiar actions such as acquisition of capital resources, the Commission must insist on the most cost-effective means of accommodating variable generation resources. Utilities and the Commission need to ensure that new generation facilities needed to meet demand should be flexible enough to participate in regional integration efforts (for instance, be capable of quickly reducing generation levels when needed by the utility or the region).

In sum, our view is that proposals to add generating resources for the express purpose of integrating variable generation should receive rigorous Commission scrutiny. The Commission can signal that, for a new integrating resource to be considered prudent, it must have been developed only after other integration alternatives are exhausted and only if other generating resources added to meet utility load have been chosen with a view toward the flexibility that will be important in a power system with increasing amounts of variable generation.

4) *Increased Certainty of Recovery of Costs of Renewables.* Should the Commission take action to provide utilities with increased certainty for recovery of costs associated with renewable resources before they are constructed or acquired? What administrative actions should the Commission take to provide such increased certainty?

We do not support any form of cost-recovery before a project is constructed and in service. Allowing utilities to recover construction work in progress or other development costs as they are incurred inappropriately shifts development risk to ratepayers that should be borne either by a utility and its investors or by a third party developer.

We do support more robust Commission review and approval of the utilities' general approach to planning for renewable resources—or any generating resources—which could include Commission acknowledgment of the amount and timing of additions to resource supply. There are at least two ways that the Commission could provide increased certainty without adopting a project-specific pre-approval mechanism (which we specifically do not propose, as further discussed below).

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any negative impacts on operations or reliability and the anticipated benefits have been confirmed." (http://www.oatioasis.com/NWMT/NWMTdocs/ADI_Evaluation_022008.pdf)

1. <u>IRP Action Plan Acknowledgment</u>. One option would be to adopt, for the entire portfolio of renewable and non-renewable resources, an integrated resources plan (IRP) review and action-plan acknowledgment model similar to that used in Oregon.

As part of their Oregon IRPs, utilities provide a near-term action plan "with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources. . . with the key attributes of each resource specified as in portfolio testing."[18] The utilities also must identify a proposed acquisition strategy, assessing the advantages and disadvantages of owning generation versus buyer power, and identifying any benchmark resources they plan to consider in later competitive bidding.[19] In acknowledging a utility's near-term action plan, the Oregon Public Utility Commission (OPUC) does not address cost-recovery for any specific resource decision but gives the utilities some increased certainty that the OPUC approves of its general resource acquisition approach. "[A]lthough favorable rate-making treatment is not guaranteed by acknowledgment of a plan," the OPUC gives "considerable weight to utility actions that are consistent with acknowledged integrated resource plans."[20] Even more importantly, the acknowledgment process allows the OPUC to alert the utility if its plans are dramatically off-course from OPUC expectations.

Another way to increase utilities' certainty about cost recovery could be to incorporate more stakeholder participation and independent review into the RFP process for major resource acquisitions. In Oregon, for example, a draft RFP must be reviewed with stakeholders and approved by the OPUC in a public process before being released for bids.[21] An independent evaluator is used in each IRP to review the score for the benchmark resource and to independently score all bids.[22] More advance review and oversight in the RFP process can increase certainty that the results reflect a prudent acquisition.

2. <u>I-937 Implementation Plans</u>. A second option would provide increased certainty only for renewable resource planning, requiring a less dramatic change to Washington's regulatory structure. Utilities could submit periodic I-937 implementation plans for Commission review in advance of the RPS target date, allowing the Commission to acknowledge utilities' general approach to RPS compliance.

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[18] Oregon IRP Guideline 4(n). OPUC Docket No. UM 1056, Order No. 07-002, Appendix A, p. 4-5 (January 8, 2007), available at http://apps.puc.state.or.us/edockets/docket.asp?DocketID=10081.
[19] Oregon IRP Guideline 13. OPUC Docket No. UM 1056, Order No. 07-002, Appendix A, p. 7 (January 8, 2007), available at http://apps.puc.state.or.us/edockets/docket.asp?DocketID=10081.
[20] OPUC Order No. 89-508, at p. 11.
[21] OPUC Docket No. UM 1182, Order No. 06-446, Appendix A (August 10, 2006), available at http://apps.puc.state.or.us/edockets/docket.asp?DocketID=12222.
[22] *Id.*

The Oregon RPS uses this model. In addition to requiring a compliance report after the target year, the Oregon RPS law requires utilities to file implementation plans beginning one year in advance of the first target year and every two years thereafter. The implementation plans are to include a calculation of the utility's MWh target; a description of the planned method to comply; identification of the owned and contracted generating facilities expected to provide RECs; and a cost forecast.[23] Implementation plans, which are required to be consistent with a utility's IRP, are reviewed and acknowledged (or acknowledged with conditions) by the OPUC in a manner similar to that used for IRPs. The Oregon utilities' first implementation plans for Oregon were filed in January 2010 and acknowledged in May 2010.[24]

In sum, advance review of a utility's plan for complying with the RPS could give utilities greater certainty about their general approach, while avoiding pre-approval of particular projects or contracts. As further discussed below, we do not propose project-specific pre-approval, because we believe that the utilities can and should continue to have the responsibility to analyze the lowest cost resources to achieve their planning needs, and to demonstrate to the Commission that they have made cost-competitive decisions. Renewable resources are like traditional acquisitions, and the basic cost-recovery model is sufficient.

5) *Consideration of Costs for Pre-approved Facilities.* Assuming the Commission pre-approves an acquisition of a site for a renewable resource like a wind site, to what extent would the Commission be limited in its review of the costs at a later time?

We do not propose project-specific pre-approval here, because we believe that it can inappropriately shift development risks to ratepayers. For the same reason, we do not support approval of preliminary development or carrying costs for utility renewable projects. Passing on development risk and real-time carrying costs to ratepayers can distort the market and potentially result in development of less economically efficient projects, if preliminary approvals give a project momentum that its economics alone would not generate.

Early Compliance with RPS

6) *Statutory Barrier.* Is the early acquisition of RPS resources limited by the Washington statutory provision (RCW 80.04.250) requiring an asset must be used and useful to earn a return?

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[23] OAR 860-083-0400; ORS 469A.075.

[24] Information on these dockets can be found, for PacifiCorp, OPUC Docket No. UM 1467 at http://apps.puc.state.or.us/edockets/docket.asp?DocketID=15988; and for PGE, OPUC Docket No. UM 1466, at: http://apps.puc.state.or.us/edockets/docket.asp?DocketID=15987.

The "used and useful" standard does not prevent recovery of costs for renewable generation resources acquired in advance of RPS target dates. The phrase "used and useful for service in this state" means that a resource benefits ratepayers in Washington "directly (e.g., flow of power from a resource to customers) and/or indirectly (e.g., reduction of cost to Washington customers through exchange contract or other tangible benefits)."[25] The test for including a system-wide resource in Washington rates is not whether it is "needed, deliverable, and least-cost, but rather whether it provided quantifiable direct or indirect benefits to Washington commensurate with its proportional cost."[26]

There is no question that a renewable generating facility that is actually used to provide service to Washington ratepayers is used and useful, regardless of whether it is presently needed for RPS compliance. Even if an operating renewable facility capable of providing service to Washington ratepayers is not needed to meet load in the immediate term (as with the Mint Farm acquisition discussed above), its power can be sold and the proceeds used to lower rates; this provides an indirect benefit to Washington ratepayers.

Likewise, any operating facility whose output qualifies for the Washington RPS is "used and useful for service in this state" when its bundled power and/or RECs are needed for the utility to comply with state law and avoid penalties for non-compliance. This does not imply that the resource was prudently acquired, which is a separate regulatory test.

7) *Changing Technology.* Does a company that acquires renewable resources early, run the risk of missing future technological changes that may have the potential to reduce the costs of the new resources if acquired at a later time?

No one can accurately predict—for any type of resource—exactly how the interplay between technological improvements, demand, and other price factors will affect future resource options. The only thing that a company can do in a given moment is make a reasonable decision based on available information.

Information concerning wind technology development provides an example. As further explained in Exhibit B to these comments, the information available from national labs and other anecdotal sources suggest several trends in wind power cost and technological advancement: (1) costs for wind projects declined dramatically from the 1980s to mid-1990s, then leveled and increased slightly through 2009; (2) capacity factors for wind projects began to level off in 2006-07, though this effect may have had less to do with a plateau in technological improvement than with transmission and other operational constraints; and (3) wind turbine prices at the end of

[25] Docket No. UE-050684, WUTC v. PacifiCorp, Final Order at 50.
[26] *Id*.

2010 are expected to be at least 15% lower than they were at the end of 2008, which is expected to result in lower installed costs for projects coming on-line in 2011.[27] Technological improvements do not appear to have affected costs or capacity factors significantly in the last few years; broader economic and demand forces have been more significant.

We can predict that, as RPS dates in various states come closer, demand for renewable resources and sites will increase, countering any downward cost trend created by technological improvements. Early acquisition in this environment can be prudent because it recognizes current economic conditions that appear to be favorable, and it recognizes that optionality decreases and price risk increases as the RPS target dates approach. (We discuss this issue further in our response to Question #14.)

8) *External Incentives.* To what extent should external incentives that are short-term in nature be a factor in Commission approval of acquisition of renewable resources in advance of RPS requirements (e.g., Production Tax Credits, Investment Tax Credits and Treasury Grants)? Will the subsidized costs attributed to external incentives compensate ratepayers for early recovery in rates?

As part of their showing of reasonableness in prudence review, utilities should be encouraged to explain how the existence of government financial incentives made the timing and nature of an acquisition prudent. It is not possible to predict, especially outside the context of a particular project, whether incentives will completely offset earlier recovery in rates. In general, however, taking advantage of significant state and federal incentives will lower costs to ratepayers—anecdotally, in the range of 15 to 20%. Utilizing those incentives is consistent with the policy preferences that have led the Washington legislature to champion renewable resource development in Washington by extending the renewable sales tax exemption. Because these financial incentives are short-term and change frequently, the Commission should not specifically address them in rules; the Commission should, however, signal that they can be an appropriate factor in a decision to acquire a renewable resource.

9) *Additional Flexibility:* Does the Commission presently have authority to consider a more "flexible" or "systematic approach" for assessing renewable resources? If so, what specific mechanism is needed?

The Commission has significant flexibility in its regulatory mechanisms. That flexibility allows the Commission to use its existing framework to manage new technological and regulatory innovations. This is why we have recommended retention of the traditional prudence analysis.

[27] *See* Exhibit B to Joint Comments of RNP, NWEC, et al.

However, in recognition that more interaction between utilities, stakeholders, and the Commission could improve planning and cost-recovery for new renewables, we have also suggested (above, in Question 4) some additional planning mechanisms, including an RPS implementation plan.

<u>Renewable Energy Credits (RECs)</u>

10) *Do Rules Conflict with Statute?* Does WAC 480-109-020 (1) (2) conflict with provisions in RCW 19.285.040(2)(e)? Discuss barriers to a company's use of RECs caused by the statutory timing of their creation?

The rules here are faithful to the statute. RCW 19.285.040(2)(e) states in part, "The requirements of this section may be met for any given year with renewable energy credits produced during that year, the preceding year, or the subsequent year." WAC 480-109-020(1)(2) further provides that those renewable energy credits (RECs) must be "acquired by January 1 of the target year." That provision reflects the language in RCW 19.285.040(2)(a), which requires qualifying utilities to meet annual renewable energy targets "by January 1" of each year beginning in 2012.

A detailed legal analysis of this issue took place during the Commission's I-937 rulemaking process, and we adopt by reference the analysis provided by the Coalition, Northwest Energy Efficiency Council, and RNP in that proceeding.[28] In particular, in that proceeding we asserted that the plain meaning of the words to "use" or "acquire" eligible renewable resources and/or RECs by January 1 cannot be modified by rule. While the utility is permitted to rely on subsequent year RECs pursuant to the statute, the only way to give meaning to that provision and all of the other provisions of the statute is to permit the utility to rely on future RECs that are acquired by January 1 of the target year.

The legal analysis on this issue was robust and sound. Upon seeing the arguments and proposals from the various parties in the rulemaking, the Commission decided to adopt the current rules because they are consistent with the statute. Thus the rules require utilities to be in compliance by January 1 of the compliance year or pay penalties. While the Commission may not be bound by res judicata, changing a rule just a few years after its adoption should require a showing that the rule is not working (absent a showing that the legal analysis is flawed, which it is not, as described above). There has been no showing that the rule is flawed; in fact, the IOUs are well on their way to compliance with the renewable standards.

[28] Docket No. UE-061895. See Comments of the NW Energy Coalition, Northwest Energy Efficiency Council and the Renewable Northwest Project, July 9, 2007 at ps. 2-7. Additional commentary on this issue can be found in the Sept. 26, 2007 comments of Renewable Northwest Project in this Docket, at pp. 2-3.

We recognize that it is possible that an eligible renewable resource or renewable energy credit upon which the utility relied to demonstrate compliance could fail to perform due to some unexpected event during the compliance year or subsequent year (such as underperformance of a generating resource). Absent remedial action, such underperformance would result in failure to actually produce the renewable energy or REC needed to satisfy the annual target for that compliance year. In Docket No. UE-061895, we proposed rules that would provide the utility the opportunity to use more eligible renewable resource generation during the compliance year or purchase more renewable energy credits during the compliance year or subsequent year to make up for any "underperformance shortfall."[29] Under our proposal, the Commission would measure the remaining underperformance shortfall not remedied by the utility during the review of the annual report after the end of the subsequent compliance year (e.g., in June 2014 for 2012 target year) and assess a penalty for any underperformance shortfall not remedied by the utility. We believe that proposal gives meaning to the statutory requirement to comply at the start of the compliance year (while also ensuring actual production of the energy or REC) and gives meaning to being able to rely on RECs produced in subsequent years.

11) *WREGIS Agent.* What agency should be responsible for oversight of registration of renewable resources and confirmation of eligibility in Western Renewable Energy Generation Information System? Discuss the duties and responsibilities of a WREGIS Agent.

We support the current construct under which the Department of Commerce, the WUTC and the State Auditor's Office coordinate on issues related to registration of renewable resources and confirmation of eligibility in WREGIS. To the maximum extent possible, I-937 should be consistently applied across the private and public utilities. Hence, all three agencies should coordinate to determine the eligibility of renewable energy resources under WREGIS.

If one entity must be selected as the "point" for WREGIS, we recommend the Department of Commerce – specifically its Energy Policy Division – as the appropriate state agency. I-937 gives the Department of Commerce responsibility for selecting a renewable energy credit tracking system to verify RECs.[30] Commerce is charged with "develop[ing] and disseminat[ing] impartial and objective energy information and analysis" for Washington State.[31] In addition, the Department must "monitor the actions of all agencies of the state for consistent implementation of the state's energy policy including applicable statutory policies and goals relating to energy supply and use."[32] Given these roles and responsibilities, the Department seems the logical

[29] *Id.*, July 9 2007 comments at ps. 9-13.
[30] RCW 19.285.030(17).
[31] E2SHB 2658, Sec. 403(2)(b), amending RCW 43.21F, effective 7/1/2010.
[32] *Id.* at Sec. 403(2)(d).

choice to be the "point person" for WREGIS.[33] However, we would still expect substantial coordination with the WUTC and the Auditor.

WREGIS is intended to be policy neutral and will not determine whether its renewable energy certificates are eligible for particular regulatory programs such as I-937.[34] That is the role of the WREGIS Agent. The WREGIS Agent applies the definitions of eligible renewable resources and renewable energy credits in RCW 19.285.030 to projects proposed for registration in WREGIS. The Agent then makes a determination as to whether those projects meet the requirements in the statute. The benefit of this approach is that utilities have more certainty regarding their potential acquisitions.[35] We recognize that the Agent ultimately is liable for these decisions.[36]

12) *REC Banking.* Does the current limited REC banking requirement impede renewable acquisition? How would unlimited banking of RECs remove barriers to the acquisition of RPS resources?

No, the current REC banking provision does not impede renewable acquisition. In contrast, the REC provision allows utilities significant flexibility in meeting the renewable standards. A utility can choose whether or not to acquire RECs – there is no requirement to do so. And if a utility opts to pursue RECs, it has a generous three-year timeframe in which to do so.

The majority of states with renewable portfolio standards have established a REC life at three years or fewer.[37] Based on data collected through Spring 2009,

- 5 states (+ NJ for all technologies except solar) either don't use or don't allow RECs, i.e., no life (CT, HI, IL, IA, NY, NJ except for solar)

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[33] Alternative options do not seem workable. Public utilities may resist having the WUTC as the point with WREGIS because of perceptions regarding regulation versus local control. IOUs may resist having the Auditor's office in that role. While the concept of an independent third party has some merit, such an entity would need funding and direction from somewhere, and would need to be liable for decisions regarding eligibility of RECs to meet I-937.

[34] WREGIS Account Holder Registration Agreement (also referred to as "The Terms of Use"), June 22, 2007, at Recitals ¶ 5.

[35] Generally, the procedures of the Auditor and the Commission focus on after-the-fact assessments of compliance with the renewable energy standard rather than providing any "pre-approval." Determining whether a renewable resource is eligible to meet I-937 does not constitute pre-approval in our minds, but does provide some level of assurance that the output meets the definitions in the law.

[36] For example, a developer whose project is deemed ineligible for I-937 may decide to sue the state. WREGIS requires that an Account Holder must have the capacity to sue or be sued under the law of a state or a federal government. (WREGIS Account Holder Registration Agreement, June 22, 2007, at Sec. 5a.)

[37] The Union of Concerned Scientists tracks individual renewable portfolio standards, including RECs. (http://www.ucsusa.org/res and under the Compliance, Tracking, and Enforcement search tab, select "Flexibility - Banking/borrowing of credits")

- 2 states (and NJ for solar only) authorize a 2-year REC life (ME, NC for certain applications, NJ for solar only)
- 1 state authorizes a 2- to 3-year REC life (MT)
- 10 states and Washington D.C. authorize a 3-year REC life (DE, DC, MD, MI, MO, PA, TX, MA, NH, RI, WA)
- 2 states authorize a 4-year REC life (NV - but PUC can extend life more, NM)
- 3 states authorize a 5-year REC life (MN, OH, WI)
- 1 state authorizes a 5- to 6-year REC life (CO)
- 1 state authorizes a 10-year REC life for certain applications (NC)
- 3 states authorize an unlimited REC life (OR, AZ, CA)

Washington's REC provision is somewhat unique in that it allows a utility the flexibility to borrow forward on renewable energy production, i.e., to use RECs before they are produced. Two other states (CO, NH) allow a similar approach, though Colorado's forward banking option expires in 2010. While most laws regulating RECs provide for a REC to commence at the time the electricity is produced, Minnesota (as well as CO and NH) commence the life of the REC in the year it is produced, which is also a form of borrowed compliance (e.g., if the electricity is not generated until December but the utility counts it in January of that same year).

Rather than removing barriers to renewables acquisition, unlimited banking of RECs would have the effect of delaying acquisition of new renewables. Longer banking periods promote hoarding behavior, which distorts the market and generally raises prices. Longer banking periods also undermine one of the key goals of I-937 – the orderly, sustained development of the renewable energy market.

Of course, the Commission cannot authorize unlimited banking unless the Legislature modifies RCW 19.285.040. Continued discussions of amendments to I-937 create uncertainty for utilities, ratepayers and the market. Suppliers and developers—and markets generally—value certainty. However, RPS policies that are subject to frequent changes introduce uncertainty into the market. In particular, some states have modified their renewable resource and technology eligibility definitions, or the manner in which renewable energy production, and thus compliance, is measured. This has resulted in large REC market price swings. Such uncertainty is a disincentive to investment in new renewable energy projects.[38]

Incentives

13) *Incentives.* Should the Commission provide incentives, financial or otherwise, for utilities that exceed their RPS targets or meet them early? If financial incentives were

[38] Cory, K.S. and Swezey, B.G. National Renewable Energy Laboratory. *Renewable portfolio standards in the states: Balancing goals and implementation strategies.* Technical report NREL/TP-670-41409, December 2007. At p. 17.

provided, what incentive design would be appropriate and would the incentives be subject to any constraints? What would be examples of non-financial incentives?

Providing more certainty regarding cost recovery to utilities via mechanisms such as those discussed in our response to Question #4 can be a powerful non-financial tool to encourage utilities to meet their targets early.

A rate of return (ROR) adder is one form of financial incentive the Commission could consider. The state has some history with using this type of incentive. RCW 80.28.025, enacted in 1980, directed the Commission to adopt policies to encourage meeting energy demand with new renewable resources. Those policies included, "allowing a return on investment in … projects which produce or generate energy from renewable resources which return is established by adding an increment of two percent to the rate of return on common equity permitted on the company's other investment." Various conditions applied to that incentive, including a timeframe for project construction between June 1980 and January 1990, and allowance of the ROR increment for a period not to exceed 30 years after the project was first placed in the rate base. The RCW 80.28.025 program has effectively expired, and a legislative re-authorization would be required to reinitiate it.

The Commission could consider whether a similar mechanism could be appropriate in the regulatory context. We would suggest focusing on an increased ROR for portfolios that reduce overall greenhouse gas emissions by a specified amount, rather than establishing different rates of return for particular projects. An incentive based on the overall portfolio would be administratively simpler and would encourage utilities to find the most economically efficient manner of achieving environmental benefits.

The Commission also could consider whether it would be appropriate to provide incentives for utilities to diversify their acquisition of eligible renewable resources.

14) *Impact on Ratepayers.* What would be the impact on ratepayers of providing incentives to utilities to exceed their RPS targets or meet them early?

Encouraging utilities to meet their RPS targets early can help protect those utilities and their customers from the risk of future natural gas price spikes, because renewable resources are not subject to gas price risk. It will also protect utilities and their customers from renewable energy generation cost spikes – if utilities see attractive buying opportunities, they should be encouraged to move ahead . New technologies will continue to enter the market and possibly will drive down prices over the long-term. However, demand for eligible renewable energy generation projects and RECs may have a countervailing impact on prices as each new target year approaches. Plus, the current trend in the United States is towards augmentation of existing renewable energy standards and adoption of new renewable standards, increasing competition for eligible projects.

Incenting early acquisition can reduce the risk of higher prices a utility may face if it waits too long to acquire resources needed to meet the standard. In theory, this is akin to analyses conducted for energy efficiency showing that accelerated acquisition reduces cost and risk for utilities and their customers.

Encouraging utilities to exceed their ultimate RPS target (i.e., 15% of load by 2020) also can reduce risk for the utility and its customers, in this case, the risk of future carbon regulation as well as the risk of additional state and/or federal policies mandating utilities meet higher renewable standards.

The effect on ratepayers of providing incentives to utilities to exceed their RPS targets or meet them early will depend on many factors, including the type and design of the incentive, and the assessed value of the risk reduction achieved by the utility from earlier or higher acquisition.

15) *Consideration of Externalities.* To what extent may, or should, the Commission require a utility to consider "positive externalities" in resource acquisition, such as impact on local economy?

As we indicated in our statement of issues and positions, we recommend that the Commission consider adopting a climate change and carbon planning requirement. The Commission should require utilities to develop integrated resource plans that meet adopted state and federal carbon reduction targets. Alternatively, the Commission could require utilities to develop two planning exercises: (1) a plan on meeting state and federal carbon reduction targets;[39] and (2) scenarios for complying with the likely future regulation of greenhouse gas emissions, as the Oregon PUC has mandated.[40] Short of requiring plans that meet target emission standards, these planning exercises can help utilities and ratepayers better understand the likely costs of eliminating the climate change externalities associated with non-renewable resources and the cost risks potentially associated with failing to plan for future carbon regulation.

A climate change and carbon planning requirement would be consistent with the statutory definition of "lowest reasonable cost" within the State's integrated resources planning law:

> "Lowest reasonable cost" means the lowest cost mix of generating resources and conservation and efficiency resources determined through a detailed and consistent analysis of a wide range of commercially available resources. At a minimum, this analysis must consider resource cost, market-volatility risks, demand-side resource uncertainties, resource dispatchability, resource effect on system operation, the risks imposed on the utility and its ratepayers, *public policies regarding resource preference*

[39] See, e.g., Washington Executive Orders 09-05 (Washington's Leadership on Climate Change); 07-02 (Washington Climate Challenge).

[40] In June 2008, the Oregon PUC adopted a carbon planning requirement as its IRP Guideline 8. See OPUC Order No. 08-339 (UM 1302), Exhibit C (available at http://apps.puc.state.or.us/orders/2008ords/08-339.pdf).

adopted by Washington state or the federal government, and the cost of risks associated with environmental effects including emissions of carbon dioxide.[41]

We would not advocate for inclusion of impacts to the local economy as a positive externality that should be considered in a utility's resource decision-making. I-937 already provides an incentive for utilities to purchase resources located in Washington State,[42] which will encourage local economic development.

16) *Hydroelectric Generation.* How does the restrictive treatment of hydroelectric generation limit clean and low-cost renewable energy options to ratepayers? Does the restriction give companies a sufficient incentive to finance efficiency improvements in older hydroelectric projects?

I-937 is intended to build on the region's existing hydropower base. Hydropower already comprises approximately 65% of Washington's fuel mix.[43] PSE's fuel mix includes approximately 41% hydropower and Avista's fuel mix is at approximately 51% hydropower.[44] In order for Washington's renewable energy standard to be meaningful, it needed to be focused on diversifying our renewable base.

The definition of eligible renewable resources in I-937 includes hydro efficiency upgrades at existing facilities. Several of the I-937 qualifying utilities, including for example Avista, Chelan County PUD, and Grant County PUD, have announced plans to pursue efficiency upgrades within their hydropower facilities and count those upgrades towards compliance with their renewable energy standards.[45] The law appears to be providing a sufficient additional incentive for utilities to finance efficiency improvements in existing hydropower facilities.

Other Issues

17) *Allowing Expanded Area.* If the geographical area for qualifying energy was expanded to areas outside the Pacific Northwest, how would the increase in eligible resources available for RPS compliance benefit ratepayers? To what extent would the expansion of the geographical "footprint" allow for additional delivery flexibility?

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[41] RCW 19.280.020(11) (emph. added).
[42] RCW 19.285.040(2)(h) allows utilities to count an eligible renewable resource at one and two-tenths times its base value if it utilized state-approved apprenticeship programs during facility construction.
[43] Dept. of Commerce, 2008 Washington State Electric Utility Fuel Mix
[44] *Id*. Note that PacifiCorp elected the Northwest Power Pool Net System Mix as its fuel mix, rather than declaring the actual resources it owns and contracts, so its fuel mix report (including 40% hydropower) does not reflect what is actually delivered to the Company's Washington customers.
[45] Public Utility District No. 1 of Chelan County Integrated Resource Plan 2008, at p. 2; Grant County PUD 2008 Integrated Resource Plan Executive Summary at p. 2; Avista's 2009 Electric Integrated Resource Plan, at p. 2-23.

The geographical restriction established in I-937 (i.e., resources must be acquired within the Pacific Northwest or delivered on a real-time basis into Washington) benefits Washington and the region by promoting local economic development. For example, according to a 2006 analysis by the Union of Concerned Scientists, implementation of I-937 will provide Washington by 2025 with $2.9 billion in new capital investment, $167 million in new property tax revenues or payment in lieu of taxes for local communities, and $30 million in income to rural landowners from wind power land leases.[46]

The Legislature would need to amend I-937 in order for the geographic region to be expanded, e.g., to encompass the entire Western Electricity Coordinating Council (WECC). We are open to discussions—in the appropriate legislative forum—that would include changes to the geographical restriction as part of a comprehensive discussion of the entire range of I-937 considerations.

18) *Decommissioning Requirements.* Discuss the statutory provisions that recognize the Commission's primacy over the decommissioning of renewable resources held by a regulated utility. To what extent are counties providing for facility decommissioning requirements for regulated utilities and can the companies quantify the excess duplicative costs?

We have no opinion on this question at this time.

19) *Cost Cap for Renewables.* Does the current cost cap provided in RCW 19.285.050 *Resource Costs*, provide effective protection for ratepayers? How specifically should the Commission implement this Cost Cap?

Yes, the cost cap provides effective protection for ratepayers. The cost cap guarantees that a utility does not need to spend more than four percent of its total annual retail revenue requirement on the incremental cost of eligible renewable resources needed to meet the renewable energy standard.[47] Most utilities will spend less, but the cost cap provides an additional safeguard.

We note that the cost cap is not an absolute. In other words, the law provides utilities with the option of meeting a lesser renewable energy standard if their expenditures reach the cost cap. But the statute is clear that "a utility may elect to invest more than this amount."[48]

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[46] UCS. *The Washington Clean Energy Initiative: Effects of I-937 on Consumers, Jobs and the Economy (2006),* p. 26. http://www.ucsusa.org/clean_energy/solutions/renewable_energy_solutions/the-washington-clean-energy.html
[47] RCW 19.285.050(1).
[48] RCW 19.285.050(1)(a).

20) *Costs and Benefits of Voluntary Green Power Programs.* How can ratepayers that participate in the voluntary green power program participate in the benefits of the program?

Lack of price volatility is a significant benefit of investing in renewable energy resources, and could be allocated to green power program participants in accordance with the level of their participation. For example, in 1999, Eugene Water and Electric Board (EWEB) began offering its customers a voluntary renewable energy product ("WindPower") directly linked to the Foote Creek Rim wind project in southwest Wyoming.[49] Customers could opt to pay a premium fixed price and choose among four levels of wind power in their resource mix: 10%, 25%, 50% or 100%.[50] Towards the end of the program, some households purchasing 100% of their power from this dedicated wind project saved money on their energy bills compared with what they would have paid under EWEB's standard retail rate.[51] There have been some discussions within Oregon's portfolio options committee, which determines the IOUs' voluntary offerings, about a similar product. The Commission could explore designing a voluntary green power program that would guarantee each participant a fixed rate for that portion of its resource mix served by the dedicated renewable energy product.

We also support utilities developing voluntary programs involving the long term contractual purchase or ownership of renewable energy generation that result in a return on investment for the participants—a form of virtual net metering, where the generation of resources in the voluntary programs return a revenue stream to program participants based on prevailing wholesale electric prices. Such programs may provide a limited hedge to participants against rate volatility. In particular, utilities with PCA mechanisms should be encouraged to offer a renewable-based alternative that is exempt from market-related rate adjustments.

21) *Other Issues.* Comment on any other issue relevant to this inquiry that is not covered above.

None at this time.

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[49] Northway, M. EWEB. *apps3.eere.energy.gov/greenpower/conference/6gpmc01/northway01.pdf at 6.*
[50] *Id*. at 10-11.
[51] In 2007, new subscriptions to the EWEB Windpower program were suspended when the output from the Foote Creek Rim wind project became fully subscribed. In 2008, EWEB combined these two renewable energy programs and moved forward with a single EWEB Greenpower program. (http://www.eweb.org/greenpower/faqs) Greenpower is similar in structure to many other northwest utility voluntary green power programs – the utility blends electricity from a variety of renewable energy projects into a single product that is purchased by customers on a voluntary basis.