REPORT ON THE POTENTIAL FOR COST-EFFECTIVE DISTRIBUTED GENERATION IN AREAS SERVED BY INVESTOR-OWNED UTILITIES IN WASHINGTON STATE

Docket UE-110667

Prepared by:

Washington Utilities and Transportation Commission

October 7, 2011

TABLE OF CONTENTS

I. Introduction 1

II. Investor-Owned Utilities and Distributed Generation 5

A. Laws and Rules Governing Electric Power – Generally 6

B. Resource Planning 7

C. The Energy Independence Act and Renewable Portfolio Standards 8

D. Purchases from Qualifying Facilities under the Public Utility Regulatory Policies Act (PURPA) 9

E. Net Metering 10

F. Interconnection Rules 11

G. Summary 12

III. Issues and Challenges in Promoting Distributed Generation 14

A. Interconnection Issues 14

B. EIA Issues 19

C. Net Metering 20

D. Questions Concerning PURPA Contracts 24

1. Renewable energy credits severable from electricity sales under PURPA 24

2. Certainty in the length of PURPA standard offer contracts. 26

E. Financial Incentives for Distributed Generation 27

1. Washington State Tax Incentives 27

2. Cost Recovery Incentive for Customer-Generated Renewable Energy Systems and Community Solar Projects and Feed-In Tariffs 29

IV. Conclusion and Recommendations 33

I. Introduction

Context and Background

The House Technology, Energy and Communications Committee of the Washington House of Representatives (TEC Committee) is conducting a project during the interim between the 2011 and 2012 legislative sessions to "identify and develop a set of policy actions to advance distributed energy in Washington, including potential legislation to encourage the growth of distributed energy in the state." The Committee requested that the Washington Utilities and Transportation Commission (UTC) contribute to this interim project by "conducting a study of distributed generation issues applicable to investor-owned electric utilities." Specifically, the UTC has been asked to provide "background information and detailed discussion to the TEC Committee and the Legislature of the available options to encourage the development of cost-effective distributed generation in areas served by investor-owned utilities, as well as the opportunities and challenges facing investor-owned utilities and their ratepayers in developing distributed generation in this state."[1]

The TEC Committee also requested that the Washington Department of Commerce (Commerce) consider the development of distributed energy resources in the State Energy Strategy. While Commerce has focused on distributed *energy*,[2] the UTC has followed the Committee's direction to scope its inquiry more narrowly on the "active," electricity-producing technologies, i.e., "distributed generation." In addition, while distributed generation may include non-renewable technologies, the UTC has focused in its study on those renewable energy technologies defined within the state Energy Independence Act (EIA), as these technologies are also the focus of several financial incentives available for distributed generation.[3]

Overview of Recommendations

Washington State's reliance on hydroelectric generation makes its electric system one of the lowest emitters of greenhouse gasses among all states. To further reduce the state's carbon footprint, Washington's laws and rules encourage development of renewable technologies through a significant renewable portfolio standard (RPS), net metering requirements and financial incentives, among other things. A review of the various renewable resource

---

[1] June 9, 2011, letter from Representative Deborah Eddy on behalf of the Technology Energy and Communications Committee to Jeffrey Goltz, Chairman, Washington Utilities and Transportation Commission is attached to this report as Appendix 1.

[2] Although several stakeholders submitted comments related to opportunities for energy efficiency by capturing waste heat from existing sources for use in thermal applications rather than power production, the UTC's focus left these distributed energy issues to Commerce to address in the State Energy Strategy.

[3] *See* RCW 19.285.

technologies identified as "eligible" resources under the EIA indicates that distributed generators must compete directly with the cost of electricity largely influenced by low-cost hydroelectric facilities, requiring additional financial incentives or tax relief to be cost-effective compared to existing facilities or utility-scale development of renewable resources.[4] These "eligible" resources include solar, wind, hydrokinetic (water, tidal, and wave), biomass, biogas and geothermal resources.[5]

After reviewing stakeholder comments and considering the discussion during the July workshop, several topics arose as the most likely prospects for actions to promote cost-effective development of distributed generation. These proposals are not specific to any one generation technology, but involve laws or rules that cut across technologies.

Given the current budget pressures in Washington, the UTC limits its recommendations to actions that will support distributed generation without unreasonably increasing costs or other burdens on ratepayers or taxpayers, or requiring additional state financial support. These recommendations offer opportunities to remove requirements that may be overly burdensome, or that may no longer be necessary. The recommendations also focus on improving the efficiency of utility services to distributed generation developers and efficiency and clarity in the legal frame work and regulations surrounding distributed generation. Further, the recommendations aim to gain a better understanding of the role of distributed generation in how utilities provide service to their customers, and the costs and benefits to the utilities of incorporating distributed generation in their electric system.

The UTC recommends the Legislature consider the following actions:

- **Amend RCW 80.60, Net Metering, to increase the cap from 100 kilowatts (kW) and clarify whether third-party ownership of generation facilities results in the third-party owner being an electric company subject to UTC regulation.** This occurs in circumstances where the third party develops and installs the generating resource on a utility customer's property, and sells the electric output to the customer, who engages in net metering with the utility.

---

[4] *See* Appendices 3-7.

[5] The UTC did not review the potential for energy storage technology in this report, as it is not a generation technology. However, the UTC recognizes that storage is a critical technology in managing the generation of intermittent power from certain renewable resources. As such, energy storage is an important complement to distributed generation.

- **Amend definitions in the Energy Independence Act, RCW 19.285.030,** of "eligible renewable resource" to include combined heat and power resources, and "distributed generation" to clarify the meaning of the term "generating capacity."

- **Review comprehensively the existing financial incentives for distributed generation**, e.g., cost recovery mechanisms, tax credits, tax reductions and exemptions, net metering, and multiple renewable energy credits to determine whether the incentives are consistent and work together in promoting cost-effective distributed generation.

- **Gather Information to Analyze the Costs and Benefits of Varying Levels of Distributed Generation.** Request a group of utilities, representative of utility systems in Washington, to perform initial cost/benefit analyses of distributed generation resources assuming different levels of system peak load (e.g., .25, .50 and 1.0 percent) to provide legislators and other decision-makers with better information to shape state policies.

Certain actions are appropriate for the UTC to address through its current statutory authority. These recommendations include:

- **Review Interconnection Rules (WAC 480-108).** Initiate a rulemaking to determine whether to amend certain rules governing the interconnection of generation facilities with utility electric systems, including requirements for external disconnect switches and insurance, and whether to adopt unique interconnection rules for generators between 300 kW and 20 megawatts (MW).

- **Clarify ownership of renewable energy credits (RECs) under Public Utility Regulatory Policies Act (PURPA) contracts** between developers and utilities through petitions for declaratory ruling, policy statements or rulemaking.

- **Provide greater certainty for developers of distributed generation through longer duration standard offer PURPA contracts** established under utility tariffs, such as Puget Sound Energy's Schedule 91.

UTC Process

In conducting this study, the UTC provided notice to a broad group of interested persons, offered stakeholders two opportunities to submit comments and hosted a well-attended workshop to gather stakeholder perspectives.[6] Working closely with the State Energy Office at Commerce,

---

[6] The UTC issued a Notice of Workshop and Opportunity to Comment on June 24, 2011, and received extensive comments from many interested parties on July 15, 2011, then hosted a workshop on July 25, 2011. On July 29, 2011, the UTC issued a Notice of Opportunity to File Additional Comments, and

the UTC sought and received technical assistance from the National Renewable Energy Laboratory (NREL), and collaborated on research and the development of a set of recommendations for actions the state could take to address challenges to the development of distributed energy resources, either through legislation or agency actions.

The UTC approached the study by examining the various laws and rules that affect the development of distributed resources, including the definition of distributed generation, how generation resources are connected to the electric grid and the availability of financial incentives to encourage the development of such resources. Some of these laws and rules affect resource development generally, while others focus on development of renewable resources. For example, the Energy Independence Act defines distributed generation to include only certain renewable resources with a capacity of less than five MW, net metering applies to customer-owned generation of less than 100 kW, and PURPA avoided cost rates apply to generation from two to 20 MW. The UTC also reviewed the potential for various renewable technologies to be developed in Washington as distributed generation.

Scope of the Report

This report identifies specific issues and challenges with laws and rules that affect the promotion of distributed generation. Section II of the report describes these laws and rules generally, and offers the viewpoints of stakeholders, when available, on the benefits or challenges of the legal framework. Section III of the report describes the specific issues and challenges and identifies recommendations for addressing these issues and challenges, and whether the recommendation is one appropriate for legislative or agency action. As the issues we discuss generally apply to all resource technologies, the description of specific renewable resource technologies, and the potential of each of these resources as distributed generation are addressed in Appendices 3 through 7 of this report. Where applicable, the body of the report refers to discussion in these appendices. In the final section, Section IV, the report identifies the key recommendations for addressing the issues and challenges addressed in the report.

---

received comments on August 8, 2011. A list of the stakeholders providing comments and attending the July 25 workshop is identified in Appendix 2.

II. Investor-Owned Utilities and Distributed Generation

Distributed generation is defined under Washington law as "electric generation connected to the distribution level of the transmission and distribution grid, which is usually located at or near the intended place of use."[7] Similarly, the United States Department of Energy has defined it as "small-scale electric generation that feeds into the distribution grid, rather than the bulk transmission grid, whether on the utility side of the meter or on the customer side."[8] Distributed generation can reduce demand on the grid for energy by producing energy at or near the customer's premises.[9]

For purposes of qualifying for multiple renewable energy credits in Washington, Washington's Energy Independence Act defines distributed generation as "an eligible renewable resource where the generation facility or any integrated cluster of such facilities has a generating capacity of not more than five megawatts."[10]

There are several stated goals and purposes of distributed generation, which follow the goals established in statute and rule for the state's electric system.[11] The stakeholders identified a number of purposes. These goals include:

- Maintaining low retail electric rates;
- Maintaining reliability of the electric system;
- Fostering economic development and job creation.
- Protecting the environment;
- Ensuring energy independence;
- Protecting consumers (including protection from cost-shifts between rate classes and types of customers); and
- Ensuring sufficient returns for utility investors.

[7] RCW 80.80.010(10).

[8] U.S. Department of Energy, *National Electric Transmission Congestion Study*, 106 (2009).

[9] Lovins et al., *Small is Profitable,* Rocky Mountain Institute at 191 (2002).

[10] RCW 19.285.030(9): "'Distributed generation' means an eligible renewable resource where the generation facility or any integrated cluster of such facilities has a generating capacity of not more than five megawatts."

[11] *See* RCW 19.280.010; RCW 19.285.020; RCW 80.60.005; RCW 80.80.005(4). For investor-owned utilities, see also RCW 80.28.010(1), RCW 80.28.020, and RCW 80.28.024.

Understanding these goals and the tensions between them will help guide the development of laws and policies to promote distributed generation.

To connect to a utility's electric grid, distributed generators must enter an interconnection agreement with the connecting utility and must enter into a contract or transaction to sell electricity to the utility. A number of state and federal laws govern these transactions, the sale and purchase of the electricity generally, and the development of distributed generation resources, particularly if those resources are renewable. In this section, we provide an overview of the laws and rules governing the regulation of investor-owned electric utilities and distributed generation in the investor-owned utilities' service areas.

A. Laws and Rules Governing Electric Power – Generally

Regulation of the business of generating and selling electric power in the United States and Washington state is divided among several entities. In general, the Federal Energy Regulatory Commission (FERC) regulates the sale of electric energy at wholesale and facilities used to transmit electricity in interstate commerce, while state utility commissions regulate retail sales of electric energy and facilities used for local distribution.[12]

The UTC regulates the rates, services, facilities, and practices of investor-owned electric utilities in Washington.[13] It is responsible to "secure for the public safe, adequate, and sufficient utility services at just, fair, reasonable, and sufficient rates."[14] Investor-owned utilities serve about 45 percent of customers in the state, while municipal utilities, public utility districts and various consumer-owned utilities serve the other 55 percent. The UTC does not regulate such publicly-owned electric utilities.[15] Nor does it regulate small, independent generators that do not hold themselves out to provide electric service the general public.[16]

---

[12] 16 U.S.C. §824; *New York v. FERC*, 535 U.S. 1 (2002); *Federal Power Comm'n v. S. Cal. Edison Co.*, 376 U.S. 205 (1964).

[13] RCW 80.01.040(3); RCW 80.04.160; *see* RCW 80.04.010 (definitions of "public service company" and "electrical company").

[14] *State ex rel. PUD No. 1 v. Dep't of Pub. Serv.*, 21 Wn.2d 201, 209, 150 P.2d 709, 713 (1944); *see* RCW 80.28.020.

[15] RCW 23.86.400 (electric service cooperative not subject to UTC jurisdiction); RCW 24.06.600 (mutual corporation not subject to UTC jurisdiction); RCW 54.16.040 (public utility districts not subject to UTC jurisdiction); *see* RCW 35.21.455 (municipal utilities); RCW 87.03.015 (irrigation districts); *Inland Empire Rural Electrification, Inc. v. Dep't of Pub. Serv.*, 199 Wash. 527, 537, 92 P.2d 258, 262-63 (1939) (rural electric cooperative not subject to UTC jurisdiction).

[16] *See* RCW 80.58.010; *State ex rel. Pub. Serv. Comm'n v. Spokane & Inland Empire R.R. Co.*, 89 Wash. 599, 154 P. 1110 (1916).

To meet the electricity needs of customers in the short and long-term, IOUs must ensure they have sufficient generating capacity for both average and peak loads. Utilities meet this demand in part through utility-owned resources, and in part through the market and sales from other parties, regularly assessing and evaluating their needs through resource planning. State and federal laws and rules govern how IOUs engage in resource planning, resource acquisition and power sales, including state RPS standards, net metering and PURPA, which addresses the sale of electric power from small power production facilities. These different laws and rules are discussed in more detail below.

B. Resource Planning

All electric utilities in Washington above a certain size, including those not subject to regulation by the UTC, must develop integrated resource plans, defined as "an analysis describing the mix of generating resources and conservation and efficiency resources that will meet current and projected needs at the lowest reasonable cost to the utility and its ratepayers."[17] The UTC has implemented integrated resource planning by requiring each electric IOU to develop an integrated resource plan and update it every two years. Among other things, integrated resource plans for investor-owned utilities must contain an "assessment of a wide range of conventional and commercially available nonconventional generating technologies."[18] This includes an assessment of the costs of available distributed generation for inclusion in the utility's least cost resource modeling. Some integrated resource plans (IRPs) submitted to the UTC include an analysis of distributed generation potentials.[19]

The Pacific Northwest Electric Power and Conservation Planning Council (Council), created by Congress in the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Northwest Power Act), adopts a regional conservation and electric power plan for the Pacific Northwest every five years.[20] The Council adopted the Sixth Northwest Power Plan in 2010.[21] Though the Sixth Northwest Power Plan stated that conservation is the most cost-effective response to meeting the region's energy needs, and could meet 85 percent of the region's growth in energy needs over the next 20 years, the plan encourages utilities to develop cost-effective,

---

[17] RCW 19.280.020(9); see generally RCW 19.280.

[18] WAC 480-100-238.

[19] Examples include PacifiCorp's 2011 Integrated Resource Plan, Docket UE-100514, Puget Sound Energy's 2011 Integrated Resource Plan, Docket UE-100960 and Avista's 2011 Integrated Resource Plan, Docket UE-101482, available on the UTC web site at http://www.utc.wa.gov/Pages/default.aspx.

[20] *See* 16 U.S.C. § 839b(a), 16 U.S.C. § 839b(d)(1); RCW 43.52A. The Northwest Power Act is codified at 16 U.S.C. §§ 839 – 839h.

[21] 75 Fed. Reg. 23,823 (May 4, 2010).

small-scale, renewable generation resources and recognizes that some states in the region have RPS mandates.[22]

C. The Energy Independence Act and Renewable Portfolio Standards

Washington State, like many other states, has a renewable portfolio standard (RPS). Washington's RPS requires electric utilities serving more than 25,000 retail customers in the state to meet renewable energy targets or pay penalties. The Energy Independence Act, or EIA, requires utilities to use "eligible renewable resources or acquire equivalent renewable energy credits (REC), or a combination of both, to meet annual targets" of at least 3 percent of load by January 1, 2012, 9 percent by January 1, 2016, and 15 percent by January 1, 2020.[23]

The EIA lists nine types of "renewable resources," including wind, solar, and geothermal energy.[24] A renewable resource is "eligible" if the generation facility started operating after March 31, 1999.[25] With limited exceptions, use of fresh water by hydroelectric dams is not an eligible renewable resource.[26] Further, biomass and biodigester energy based on municipal solid waste is not an eligible renewable resource.[27]

While the EIA does not require utilities to acquire any particular quantity of distributed generation, defined as an eligible resource with generating capacity less than five MW, the EIA gives such resources special treatment. To meet the RPS targets, the statute allows a utility to:

> [C]ount distributed generation at double the facility's electrical output if the utility: (i) Owns or has contracted for the distributed generation and the associated renewable energy credits; or (ii) has contracted to purchase the associated renewable energy credits.[28]

---

[22] Sixth Northwest Conservation and Electric Power Plan, Plan Overview, 3; Action Plan, AP-1, 10-11. The Sixth Northwest Power Plan is available on the Council's website at http://www.nwcouncil.org/energy/powerplan/6/default.htm.

[23] RCW 19.285.040(2)(a). A "renewable energy credit" is a tradable certificate of proof of at least one megawatt-hour of an eligible renewable resource where the generation facility is not powered by fresh water.RCW 19.285.030 917); see *Puget Sound Energy*, 282 Pub. Util. Rep. (PUR) 4th 303, 306-07 (Wash. Utils. & Transp. Comm'n, 2010) (determining appropriate accounting of proceedings from sales of renewable energy credits.). The credits can be bought and sold in the energy marketplace. A renewable energy credit may be used once for RPS compliance. RCW 19.285.040(2)(e).

[24] RCW 19.285.030(18)

[25] RCW 19.285.030(10).

[26] *See* RCW 19.285.030(10).

[27] RCW 19.285.030(18)(i).

[28] RCW 19.285.040(2)(b).

Thus, the EIA allows RECs from generation under five MW to count as double for compliance purpose. This "multiplier" doubles the RECs for such resources.

D. Purchases from Qualifying Facilities under the Public Utility Regulatory Policies Act (PURPA)

Seeking to reduce the nation's dependence on foreign oil and encourage the development of cogeneration and small power production facilities, Congress enacted the Public Utility Regulatory Policies Act (PURPA) in 1978.[29] In Section 210 of PURPA, Congress created a market for the output of "qualifying small power production facilities" by requiring electric utilities to purchase the output under rules adopted by FERC.[30] Generally, "small power production facilities" are those that meet certain fuel use requirements and have a production capacity of no more than 80 megawatts.[31] "Qualifying" facilities are those that FERC certifies as such.[32]

Under the Federal Power Act, FERC has exclusive authority to regulate the sale of electric energy in interstate commerce by public utilities. Although states retain exclusive jurisdiction over retail electricity sales within their boundaries, they possess limited authority over certain intrastate wholesale transactions.[33] PURPA assigns the states a limited role in setting wholesale rates. Under Section 210 of PURPA, state regulators have an obligation to implement FERC rules that require electric utilities to offer to purchase electricity from qualifying small power production facilities.[34] When setting rates for those purchases, state regulators must take into account "the incremental cost to the electric utility of alternative electric energy," or "avoided costs."[35] For qualifying facilities with a design capacity of 100 kW or less, state regulators must

---

[29] *See generally FERC v. Mississippi*, 456 U.S. 742 (1982) (rejecting challenge to constitutionality of certain PURPA provisions, including § 210).

[30] 16 U.S.C. § 824a-3(a); 18 C.F.R. Part 292.

[31] 16 U.S.C. § 796(17)(A); 18 C.F.R. § 292.204.

[32] 16 U.S.C. § 796(17)(C); 18 C.F.R. § 292.203(a).

[33] *Miss. Power & Light Co. v. Mississippi ex rel. Moore*, 487 U.S. 354 (1988); *PUD No. 1. Of Grays Harbor Cnty. v. Idacorp., Inc.*, 379 F.3d 641 (9th Cir. 2004).

[34] 16 U.S.C. § 824a-3(f); *see* 18 C.F.R. Part 292.

[35] 16 U.S.C. § 824a-3(b), (d); 18 C.F.R. § 292.304. *See generally Am. Paper Inst., Inc. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402 (1983); *Whitehall Wind, LLC v. Mont. Pub. Serv. Comm'n*, 223 P.3d 907 (Mont. 2011); *Cal. Pub. Utils. Comm'n*, 132 FERC ¶ 61,047 (2010).

establish standard rates, and they may also do so for larger qualifying facilities.[36] State regulators may set different rates for different types of generating technologies.[37]

To fulfill its obligation under PURPA Section 210, the UTC has adopted a competitive contracting process in which investor-owned utilities solicit bids from qualifying facilities.[38] By UTC rule, PURPA qualified facilities with a generation capacity of one megawatt or less may accept a purchasing utility's standard (published) rates, i.e., a standard offer contract, without filing a bid, regardless of the generating technology used.[39] All three electric investor-owned utilities have filed, and the UTC has approved, tariffs implementing a standard offer contract for small qualifying facilities. Avista's tariff applies to qualifying facilities with a generating capacity of one MW or less, PacifiCorp's applies to qualifying facilities of two MW or less, and PSE's tariff, referred to as Schedule 91, applies to qualifying facilities of five MW or less.

The investor-owned utility tariffs offering a standard offer contract rate for PURPA qualified generation are based on avoided costs that include estimates of distribution cost savings. In this way, the standard offer contract already accounts for distribution savings from distributed generation. The utility offer to PURPA qualified generation facilities for larger capacity generation, i.e., from two or five MW up to 20 MWs is also based on the utility's avoided costs, which include any distribution savings.[40]

E. Net Metering

Electric utilities in Washington State must allow "customer-generators" with a generating capacity of no more than 100 kW to interconnect with the utility's distribution facilities through

---

[36] 18 C.F.R. § 292.304(c).

[37] 18 C.F.R. § 292.304(c)(3)(ii); *see In re Commission's Investigation into Disaggregation and an Appropriate Published Avoided Cost Rate Eligibility Cap Structure for PURPA Qualifying Facilities*, Case No. GNR-E-11-01, Order No. 32262 (Idaho Pub. Utils. Comm'n, June 8, 2011) (treating solar and wind differently from other technologies for purposes of establishing avoided cost rates).

[38] WAC 480-107.

[39] WAC 480-107-015(1); WAC 480-107-095(2); *see* Puget Sound Energy WN U-60 Electric Tariff G, Schedule 91, available on the UTC's website at http://www.utc.wa.gov/docs/Pages/DocketLookup.aspx?FilingID=101864.

[40] *See* WAC 480-107-055; WAC 480-107-095.

a "net metering system."[41] A "net metering system" is defined as a generation facility on the customer-generator's premises that is "intended primarily to offset part or all of the customer-generator's requirements for electricity."[42] While a net-metered system may use any source for electric generation, by January 1, 2014, a utility must make available to such customers cumulative generating capacity equal to 0.5 percent of the utility's 1996 peak demand, reserving at least half of that for "net metering systems that generate renewable energy."[43] The customer's utility bill for a given period is to be based on the difference between the electricity supplied by the electric utility and the electricity generated by the customer and supplied to the grid.[44] The statute includes provisions for required metering equipment and utility fees.[45]

Amendments to PURPA in 2005 obligated state commissions to consider whether to require electric utilities to offer "net metering service" to the consumers they serve.[46] The UTC determined that further action was not necessary, as Washington law already required net metering.[47]

F. Interconnection Rules

A small generator or developer of distributed generation, including a customer generator under the net metering statute, must interconnect with a utility's electric distribution or transmission system to sell electricity to the utility. Under the 2005 PURPA amendments, state commissions were obligated to consider whether to require electric utilities to offer "interconnection service" to the consumers they serve, using procedures that "promote current best practices of interconnection for distributed generation."[48] Under PURPA, "'Interconnection service' means

---

[41] RCW 80.60; see, in particular, RCW 80.60.010(10)(a).

[42] RCW 80.60.010(10).

[43] RCW 80.60.020(1)(a). "'Renewable energy' sources include water, wind, solar, and animal waste sources, but not plant biomass." RCW 80.60.010(14). This definition is consistent with, but does not match, the definition of "eligible renewable resource" under RCW 19.285.030(1).

[44] RCW 80.60.010(9); RCW 80.60.030; *see* Final Bill Report SHB 2773 (available at http://apps.leg.wa.gov/documents/billdocs/1997-98/Pdf/Bill%20Reports/House/2773-S.FBR.pdf).

[45] RCW 80.60.020; *see* WAC 480-108-040(7)(a), (11).

[46] 16 U.S.C. § 2621(d)(11). Subsection (d)(11) was added by the Energy Policy Act of 2005, Pub. L. No. 109-58.

[47] UTC Docket UE-060649, *Interpretive and Policy Statement Regarding Energy Policy Act of 2005 Standards for Net-Metering, Fuel Sources, Fossil Fuel Generation Efficiency and Time-Based Metering*, ¶ 10 (Wash. Utils. & Transp. Comm'n, Aug. 23, 2007).

[48] 16 U.S.C. § 2621(a), (d)(15).

service to an electric consumer under which an onsite generating facility on the consumer's premises shall be connected to the local distribution facilities."[49]

Pursuant to PURPA's directives, the UTC adopted two sets of rules to govern interconnection of customer-owned generation facilities to their electric utility's local distribution system.[50] These rules address electrical standards to ensure safety and reliability, as well as responsibility for the costs of interconnection, including interconnection study costs, distribution equipment and installation costs to prepare the system for receiving power from a distributed resource, and administrative costs. The first set of rules governs interconnection of facilities with a generation capacity of 300 kW or less. The second set applies to facilities with a generation capacity of 300 kW to 20 MW. These rules require distributed generators to pay the costs the utility incurs to facilitate interconnection with the utility's infrastructure.[51] Investor-owned and publicly-owned utilities coordinated during the UTC rulemaking to reach interconnection standards that all utilities also could apply to their own systems. Other states have adopted different approaches.[52]

FERC has adopted standards to govern interconnection of generation facilities to electric utilities' infrastructure for transmitting electricity in interstate commerce. One set of standards governs interconnection of facilities with a generation capacity of 20 MW or less.[53] The other set governs interconnection of larger facilities.[54]

G. Summary

A review of the laws and rules governing IOUs and distributed generation demonstrates that the interplay of the size and nature of the distributed resource and system determines the relationship between the generator and the IOU. The complexity of these laws and rules is demonstrated in Table 1 below.

---

[49] 16 U.S.C. § 2621(d)(15).

[50] WAC 480-108; UTC Docket UE-060649, General Order 545, Wash. St. Reg. 07-20-059.

[51] WAC 480-107-125 (PURPA qualifying facilities); WAC 480-108-035(8); WAC 480-108-040; WAC 480-108-090.

[52] For state-by-state summaries, see The Network for Energy Choices, *Freeing the Grid: Best Practices in State Net Metering Policies and Interconnection Procedures* (2010), available at http://www.newenergychoices.org/uploads/FreeingTheGrid2010.pdf.

[53] 71 Fed. Reg. 42,587 (July 27, 2006); 70 Fed. Reg. 71,760 (Nov. 30, 2005); 70 Fed. Reg. 34,190 (June 13, 2005).

[54] 68 Fed. Reg. 49,846 (Aug. 19, 2003).

Table 1 – Comparison of Various Laws and Rules Related to Distributed Generation

Law or Rule	< 100 kW	100 kW - 300kW	300 kW – 5 MW	>5 MW	Renewable	Eligible Renewable
Interconnection Rules – Part 1	YES	YES	NO	NO	No distinction	No distinction
Interconnection Rules – Part 2	NO	NO	YES	YES – up to 20 MW	No distinction	No distinction
Net Metering	YES	NO	NO	NO	YES	No distinction
RECs	YES	YES	YES	YES	No distinction	YES
Double RECs	YES	YES	YES	NO	No distinction	YES
PURPA Standard Contract, e.g., Utility Tariff	YES	YES	YES – (Avista < 1 MW; PacifiCorp < 2 MW)	YES – under PSE Schedule 91	No distinction	No distinction
PURPA Avoided Cost Rate	YES	YES	YES – above 1-2 MW	YES – up to 20 MW	No distinction	No distinction

As Table 1 shows, all generation resources that are less than 100 kW may interconnect with an IOU using one set of rules and engage in net metering, regardless of whether the resource is renewable. If the generating capacity of the interconnection generator is under the limit in an IOU's published standard contract, the generator may pursue a standard PURPA contract, but may not engage in net metering.[55] Unless power is subject to a PURPA contract, one set of interconnection rules apply to generation under 300 kW and a different set apply if it is over 300 kW.[56] If the generation is from an eligible resource and its generation capacity is less than five MW, the resulting REC is eligible to be counted as double for compliance purposes.

If the capacity of the PURPA qualifying generator exceeds that identified in the IOU's tariffed standard offer contract, the IOU must offer upon request or bid from the qualified generator a contract based on its avoided cost. If the generation is from an eligible renewable resource over five MW, the megawatt hour (MWh) of electricity produces one REC for compliance purposes.

The differing options and requirements for differing size of generation capacity and resource type have developed over time, with different purposes and goals. In some situations they present challenges for both distributed generators and utilities. A number of stakeholders filed comments in this inquiry to address some of the challenges identified in Table 1 above. We address these in the next section below.

---

[55] However, PURPA contracts, no matter what size, fall under interconnection rules in WAC 480-107.

[56] *See* n.55, infra.

III. Issues and Challenges in Promoting Distributed Generation

In this inquiry, the UTC received comments from investor-owned utilities, publicly-owned utilities, developers of distributed generation resources, state agencies and other organizations with an interest in distributed generation.[57] Each of these commenters suggested actions the Legislature or the UTC could take to address issues they have faced in working with distributed generation. In the sections below, we discuss these issues, identify stakeholder perspectives on the issues and recommend actions the Legislature or UTC could take to resolve the issue.

A. Interconnection Issues

Distributed electric generators are almost always connected to the distribution grid, the terms and conditions of which are governed by an interconnection agreement with a utility. This connection helps distributed generation achieve the system benefits often attributed to it.[58] The UTC's interconnection rules, discussed above in Section II.F., address the terms of this connection and how to allocate these costs fairly between the interconnecting generator and the utility, and ensure the reliability and safety of the generator's facilities and the utility's system. Although the UTC adopted these rules only four years ago in an extensive rulemaking, there have been technological changes and a better understanding of the needs of interconnecting generators that indicate it is time for the UTC to review certain of these interconnection rules. These rules were the focus of a number of comments during this inquiry. In addition, some stakeholders express concerns about what they see as unnecessary interconnection requirements in the rules, such as the need for external disconnect switches and insurance.

Stakeholder Perspectives

Cost

Avista states that interconnection costs vary with each distributed generation project, from a minimum cost of purchasing a production meter and ranging up to a dedicated feeder and ancillary equipment at maximum. Avista also states that these costs "presently are and should continue to be paid for by the customer-owners of distributed resources."[59] The King County

---

[57] A list of these stakeholders, including those attending the July workshop and those filing comments, appears in Appendix 2 to this report.

[58] Such benefits include, for example, overall system safety and reliability, particularly when coupled with system tools such as smart grid technologies that allow a system operator to reduce the amount of power received from distributed generators when necessary.

[59] Comments of Avista at 10 (July 15, 2011).

Department of Natural Resources and Parks (DNRP) echoes that opinion, stating that these costs should be borne by customer-owners because they are based on "the necessity to connect a system for localized use."[60]

Avista Utilities (Avista) states that the costs of integrating small distributed resources through net metering mainly stem from personnel and travel resources because the company inspects, verifies protection, and commissions each installation, which costs approximately $30,000 annually (based on 30 new installations per year).[61] While the amount of distributed generation within Avista's electric system is small and generally does not have a major impact on load, the company notes that as the number of installations increases, so will the integration costs.[62]

Puget Sound Energy (PSE) characterizes interconnection costs as dependent upon the size of the distributed generation resource, the existing load on the line into which the distributed resource will feed, and the safety equipment that is necessary to integrate the resource. For systems that do not include a UL 1741-listed inverter, or for projects larger than 300 kW, PSE states that interconnection requires a series of system impact studies that it estimates would cost approximately $25,000 in 2011 for a 500-kW to 5-MW project.[63]

PSE also notes that integration costs are dependent on the type of resource, system location, intermittency characteristics, and overall degree of penetration. Additional costs arise if distributed projects necessitate transformers, meters, larger conductors, or other upgrades.[64]

While PacifiCorp has not developed an estimate of integration costs for distributed energy resources,[65] it states that higher administrative costs, such as review of applications, billing, and regulatory requirements associated with managing net metering and interconnection programs could impact future rates, as could significant distribution and transmission system upgrades and maintenance to accommodate numerous interconnections.[66] PacifiCorp states that no changes are required to accommodate more distributed energy because the interconnection rules are flexible enough to allow interconnection and appropriately allocate the costs.[67]

---

[60] Comments of the King County Department of Natural Resources and Parks at 4 (July 15, 2011).

[61] Comments of Avista at 3 (July 15, 2011).

[62] *Id.*

[63] Comments of Puget Sound Energy at 3 (July 15, 2011).

[64] *Id.*.

[65] Comments of PacifiCorp at 2 (July 15, 2011).

[66] *Id*. at 6.

[67] *Id*. at 5.

NW Energy Coalition (NWEC) argues that the costs of interconnecting distributed systems are typically minimal and socializing them could be justified on the basis of the "added benefit brought to the grid by the [distributed generation] system," or, if interconnection costs continue to be borne by the consumer-owner, "an assumed integration cost should be included in the calculation of an appropriate incentive level."[68]

The Local Energy Alliance of Washington (WALEA) states that direct interconnection costs, such as line extensions, switch gear, and meters, should be paid for by the owners of distributed resources because such costs provide the "proper incentive . . . to plan projects where they most cost-effectively integrate with the grid," It also argued that any costs associated with "making the distribution system ready for distributed generation," including direct transfer trip relays, substation metering improvements, billing software upgrades, and system switching, should be socialized "as part of a plan to make local generation commonplace."[69]

External Disconnect Switch

UTC rules, WAC 480-108-020(2), require the use of an external disconnect switch on the customer-generator's side of the meter.[70] However, the rule permits utilities to waive the requirement for generating facilities of 300 kW generating capacity or less under some circumstances where worker safety will not be compromised.[71] In adopting these rules, the UTC emphasized that it expects utilities to ensure worker safety is not compromised if they waive the external disconnect switch requirement.[72] Under the rules, utilities will consider procedures established by the Department of Labor and Industries (L&I) for de-energizing distribution lines and equipment to protect workers.[73]

However, some stakeholders suggest that the UTC amend and simplify interconnection rules to remove the requirement for an external disconnect switch. The Interstate Renewable Energy Coalition (IREC) asserts that these switches are redundant and add significantly to overall

---

[68] Comments of Renewable Northwest Project and Northwest Energy Coalition at 7 (July 15, 2011).

[69] Comments of the Local Energy Alliance of Washington at 9 (July 15, 2011).

[70] UTC Docket UE-060649, General Order 545, ¶¶ 18, 76-80 (Wash. Utils. & Transp. Comm'n, (Sept. 27, 2007).

[71] WAC 480-108-020(2)(b). For a discussion of the background of this rule, see UTC Docket UE-060649, General Order 545, ¶¶ 76-80 (Wash. Utils. & Transp. Comm'n, Sept. 27, 2007), Wash. St. Reg. 07-20-059.

[72] UTC Docket UE-060649, General Order 545, ¶ 80; *see* WAC 296-45-335 (safety procedures for de-energizing lines and equipment to protect employees working on them).

[73] WAC 296-45-335.

project costs.[74] PSE supports investigation of the requirement for distributed systems that meet standards under the engineering standard UL 1741.[75] WALEA recommends that interconnection standards be changed "so that the cost, process, and timeline for interconnecting a distributed generation system is substantially similar to the process for connecting a similar sized load" to a utility's system, with additional standardized protective relays and disconnect switches.[76] Cascade Power Group (CPG) argues that redundant external disconnect switches and requirements for additional insurance should be prohibited.[77]

Other Interconnection Standards and Requirements

Snohomish County Public Utilities District No. 1 (Snohomish) notes that several components of the interconnection process and generator-to-utility agreements could be standardized, but says that the resource type and size and location of interconnection should determine whether a particular project needs a unique interconnection arrangement. It states that utilities should be allowed to maintain the flexibility to tailor interconnection processes to the needs and characteristics to each system configuration.[78]

CPG lists its view of general best practices for interconnection, which include setting fees for interconnection proportionately to project size, adopting "plug and play rules" for residential-scale systems, developing expedited procedures for other system sizes, ensuring fast processing for applications, and reducing costs for system impact studies.[79]

Some commenters state that the costs of insuring distributed generation systems presented a challenge in developing distributed resources. IREC recommends that the UTC lower the costs of interconnection by prohibiting requirements for additional insurance to cover liability.[80] Similarly, CPG recommends that additional insurance should not be required.[81] Utilities are legally responsible for operating their electric systems within good utility practices, and should not be liable for the operation of third-party operators of generation interconnected to their systems. However, utility operations can damage generator equipment and, conversely, operation of generation equipment can damage utility equipment. Thus, utilities carry limited

[74] Comments of the Interstate Renewable Energy Council at 9-10 (July 15, 2011).

[75] Comments of Puget Sound Energy at 3 (July 15, 2011).

[76] Comments of the Local Energy Alliance of Washington at 3 (July 15, 2011).

[77] Comments of Cascade Power Group at 4 (July 15, 2011).

[78] Comments of Snohomish Public Utility District at 3 (July 15, 2011).

[79] Comments of Cascade Power Group at 4 (July 15, 2011).

[80] Comments of the Interstate Renewable Energy Council at 12-13 (July 15, 2011).

[81] Comments of Cascade Power Group at 4 (July 15, 2011).

liability insurance to address the risk of the possibility that improper operation of their system might injure a generator. A generator also is required to have insurance to cover the damage it may cause by improper operation of its facilities, which covers its risks. The need for insurance is dictated by the risk of the interconnection between the generator and the utility.

Some commenters also recommend that the Legislature could provide statewide uniformity for interconnection requirements across utility types. IREC states that the UTC could adopt or modify FERC Fast Track screens for interconnecting projects of two MW or less to change the limit on aggregated generation on a distribution circuit from 15 percent of the line section annual peak load to 50 percent of minimum load. IREC also recommends that utilities be required to make information publicly accessible about the available capacity of distribution facilities at the circuit level to help generators identify suitable points of interconnection.[82]

Recommendations

While generators and utilities have different interests in how to pursue interconnection, given the number of comments on this issue at the workshop and in writing, it is appropriate for the UTC to review its current interconnection rules in WAC 480-107. The issues and challenges involving interconnection requirements do not require legislative action.

As technologies and policies have evolved since the UTC adopted its interconnection rules in 2007, the UTC will initiate a rulemaking to examine whether to amend certain interconnection rules, such as those concerning external disconnect switches and insurance requirements, and whether to develop simplified interconnection rules for a small range of generator capacities above 300 kW.[83]

In the rule-making inquiry, the UTC will review the current insurance requirements and whether to waive the insurance requirement for certain small-sized generators. This review will involve an assessment of how much risk there is and if it is fair to shift that risk onto the ratepayers of the utility.

The inquiry also will focus on which party should bear the costs of interconnection. This involves examining the opportunity to reduce the transaction costs of interconnection by increasing the efficiency of the process with streamlined rules tailored to the unique

[82] Comments of the Interstate Renewable Energy Council at 15 (July 15, 2011).

[83] Although there is currently an Executive Order, Executive Order 10-06, suspending non-critical rulemaking, the Executive Order allows recognizes Office of Financial Management guidelines that provide agencies discretion to conduct rulemaking under certain circumstances, including at the request of an affected industry. We believe the review of the UTC's interconnection rules in WAC 480-107 likely would meet those circumstances.

characteristics of a group of generation technologies or sizes. In reviewing the assignment of interconnection costs the UTC will be mindful of the need to preserve fair and nondiscriminatory service for customers, and avoid subsidies that inefficiently promote distributed generation. We will need to address whether it is equitable for customers without generation to pay the costs of connecting the customer-generator's system to the grid, or to provide unequal subsidies for similarly situated generators. As the IOUs noted in their comments, interconnection costs can vary greatly for two projects with exactly the same size, technology and operating characteristics depending on the location of the interconnection on the distribution system and the characteristics of the distribution system near the interconnection location.

B. EIA Issues

During the July workshop and in filed comments, several stakeholders brought forth suggestions for clarifying the definition of distributed generation in the EIA as well as amending the EIA to include additional technologies or special considerations to increase the number and type of projects that would qualify as eligible renewable resources. In addition to these stakeholder comments, we recognize that allowing RECs from generation under five MW to count as double for compliance purposes potentially also increases the REC revenue stream for such resources. We address this below in the discussion on financial incentives for distributed generation.

Stakeholder Perspectives

PacifiCorp states that the definition of distributed generation should be refined in the EIA to mean that the generation source is not interconnected to the transmission system, but instead is interconnected at a utility's distribution level and will be used primarily as, "self-generation to offset the customer's use of utility system power." [84] As such, the company views the appropriate regulatory treatment of distributed generation projects as demand-side resources or energy efficiency measures.

Avista points out that the definition of distributed generation under the EIA is not comprehensive because it does not include any non-renewable distributed generation resources. The company also comments that because the EIA does not specify where the five MW limit on distributed systems ought to be measured, the definition should be modified to read: "a generation facility or any integrated cluster of such facilities having a generating capability of not more than five megawatts *of alternating current as measured at the point of interconnection with the electricity system*."[85] CPG also commented that distributed generation should be defined as "localized generation of electric and thermal resources that are produced close to the point of use."[86]

[84] Comments of PacifiCorp at 1 (August 8, 2011).

[85] Comments of Avista at 2 (August 8, 2011) (emphasis added).

[86] Comments of Cascade Power Group and Seattle Steam Company at 1 (August 8, 2011).

Several participants in the inquiry support adding additional technology types to the list of eligible renewable distributed resources, or adding to the list of feedstock types permissible for use in biomass or biogas-based electricity production to take better advantage of and encourage technologies that may fall into a gray area between energy efficiency and renewable energy production. The Northwest Clean Energy Application Center (NW CEAC), operated by the U.S. Department of Energy, notes the opportunities to encourage the use of waste heat through combined heat and power (CHP) systems and district energy.[87] NW CEAC supports including food waste and yard waste (or "green waste") for use in high-solids digesters, and adding spent pulp and paper liquor to the list of eligible renewable technologies.[88]

Recommendations

The stakeholder comments identify several issues and concerns with the current definition of distributed generation, including the lack of a standard for determining the generation capacity for such resources, and the lack of the inclusion of combined heat and power under the definition. Including waste heat in the definition of eligible renewables in the EIA would promote efficient energy use without adversely affecting the growth of renewable distributed generation, as certain renewable resource technologies, such as biomass and biodigestion, can include waste heat economically in their operations. Legislative action is required to address these issues.

The House Environment Committee is currently undertaking an interim project to determine appropriate changes to the EIA. For this reason, we recommend the Environment Committee consider the changes proposed by stakeholders in its consideration of the policy purpose for promoting distributed generation. We further recommend the Environment Committee consider the analysis conducted by the State Energy Office at Commerce in Chapter 5 of the 2012 State Energy Strategy, which examines the challenges and benefits of extending the definition of eligible renewable resources under the EIA to include CHP.

C. Net Metering

Stakeholders raised several challenges under the current net metering statutes: whether to raise the current 100 kW cap for the generating capacity of a net metering system in Washington, whether to raise the cap for the cumulative net metered generation for a single utility, and the applicability of net metering when a third-party generates the electricity at a host site or for a community. Stakeholders assert that addressing these issues will allow for increased distributed generation in the state.

---

[87] Comments of the Northwest Clean Energy Application Center at 1-2 (August 8, 2011).

[88] *Id*. at 2.

Net Metering and Utility Capacity Caps

Other states have different caps for net metering.[89] In Oregon, for example, the cap for customers of investor-owned utilities is 25 kW for residential customers, and two MW for non-residential customers.[90] Idaho statutes do not require net metering, but the Idaho Public Utilities Commission has authorized utility net metering programs with a cap of 100 kW.[91] In 2010, Oregon implemented a pilot volumetric incentive rate program for solar photovoltaic energy systems within IOU service territories. The program emphasizes small residential and commercial systems with a maximum nameplate capacity of 10 and 100 kW, respectively.[92] Under the Oregon program, utilities pay participants an amount based on how much electricity the systems produce, whether under a net metering option or a competitive bidding option.[93]

Many stakeholders recommend that the Legislature increase the 100 kW cap for system capacity sizes allowable under Washington's net-metering statute.[94] Proponents of increasing development of distributed resources generally advocate for increasing the cap, removing it altogether, or limiting the size to the net on-site load (even in instances where the on-site load would exceed the current 100 kW limit for net-metering).[95]

PacifiCorp notes that Washington's 100-kW limit is "one of the lowest among [the company's] six-state service territory," and agreed that raising the cap could allow larger commercial facilities to participate in net-metering.[96] NW CEAC and CPG recommend increasing the cap to two MW, while NWEC recommends an upper limit of five MW to mirror the EIA limit on

[89] For state-by-state summaries, see The Network for Energy Choices, *Freeing the Grid: Best Practices in State Net Metering Policies and Interconnection Procedures* (2010), available at http://www.newenergychoices.org/uploads/FreeingTheGrid2010.pdf. A map showing state net metering caps is available on the website of DSIRE (Database of State Incentives for Renewables and Efficiency), at http://www.dsireusa.org/documents/summarymaps/net_metering_map.ppt

[90] Or. Admin. R. 860-039-0010; *see* Or. Rev. Stat. § 757.300(8) (2009).

[91] *See Avista*, No. AVU-10-10-02 (Idaho Pub. Utils. Comm'n, (July 7, 2010).

[92] Or. Rev. Stat. §§ 757.360 - .365 (2010); Or. Admin. R. 860-084-0100 - 0450.

[93] Or. Admin. R. 860-084-0360, 0365. *See generally* Public Utility Commission of Oregon, *Solar Photovoltaic Volumetric Incentive Rate Pilot Program Report to the Legislative Assembly* (Jan. 1, 2011) (available at http://www.oregon.gov/PUC/123010finalsolarreport.pdf).

[94] RCW 80.60.010(10).

[95] *See* Comments of the Interstate Renewable Energy Council at 15 (July 15, 2011); Comments of Northwest Clean Energy Application Center at 3 (July 15, 2011); Comments of the Local Energy Alliance of Washington at 12 (July 15, 2011); Comments of Renewable Northwest Project and Northwest Energy Coalition at 8 (July 15, 2011).

[96] Comments of PacifiCorp at 9 (July 15, 2011).

distributed generation capacity.[97] WALEA recommends increasing the limit as far as 10 MW.[98] Another recommendation is to remove any size limit as long as the net-metered system is designed to generate less electricity than the net on-site load.[99]

PSE, on the other hand, suggests that such a change would have little effect on the development of distributed generation resources, stating, "[i]f net metering were increased to 300 kW from 100 kW, it would still allow the low-cost interconnection projects," but that:

> [T]his change may not expand the market potential of distributed generation materially since all of the projects in PSE's service territory are typically in the 3-4 kW range, with a few above 20 kW. Accordingly, PSE does not judge the present 100 kW cap to be much of a market limitation.[100]

This suggests that consumers interested in investing in larger systems might forego net-metering in favor of a fixed-offer contract. IOUs also caution that significant increases in the number of net-metering projects will result in higher administrative costs to manage them.[101]

The net metering statute requires utilities, by January 1, 2014, to make net metering available on a first-come, first-served basis until the cumulative generating capacity of the net-metered systems equals 0.5 percent of its 1996 peak load.[102] Several participants support increasing this cap to at least 5 percent.[103] However, PacifiCorp states that it has not yet turned away a project in its Washington territory despite the current cap of 0.25 percent of 1996 peak load.[104]

---

[97] Comments of the Northwest Clean Energy Application Center at 5 (July 15, 2011); Comments of Cascade Power Group at 10 (July 15, 2011); Comments of Renewable Northwest Project and Northwest Energy Coalition at 8 (July 15, 2011).

[98] Comments of the Local Energy Alliance of Washington at 9 (July 15, 2011).

[99] See Comments of the Interstate Renewable Energy Council at 15 (July 15, 2011).

[100] Comments of Puget Sound Energy at 9 (July 15, 2011).

[101] See Comments of PacifiCorp at 6 (July 15, 2011).

[102] RCW 80.60.020(10).

[103] *See* Comments of Cascade Power Group at 10 (July 15, 2011); Comments of Renewable Northwest Project and the Northwest Energy Coalition at 8 (July 15, 2011). RNP states that it would prefer no limits be placed on the aggregated amount of net-metered systems, and further recommended that the minimum allocation reserved for net-metered systems powered by renewable resources be raised to at least 75 percent of the total allotment for net-metered systems.

[104] Comments of PacifiCorp at 9 (July 15, 2011).

Stakeholders also recommend changes to the net-metering statute to allow "community" net metering, similar to House Bill 1049 introduced in the 2011 legislative session.[105] This arrangement would allow multiple customers to invest in a single renewable energy system and have each individual's portion of the overall generation credited against his or her own utility bill. Stakeholders in support of community net metering believe that this approach would allow more individuals to participate in net metering, result in larger, more efficient systems with better siting,[106] and decrease costs and barriers for community solar projects.[107]

Third-Party Ownership

Seventeen states currently allow third parties to own facilities located on a utility customer's premises, and to sell the electricity generated at the facility to the customer, who may then engage in net metering with the utility.[108] While many customers may not be able to avail themselves of federal tax credits and accelerated depreciation for such projects, third-party owners are able to use these financial incentives, making it economically feasible to develop renewable projects such as solar photovoltaic. While Washington's net metering law does not preclude third-party ownership, IREC asserts that the law is not clear whether or not a third-party owner would be considered a public utility subject to the UTC's jurisdiction. IREC suggests the UTC could address the issue through a declaratory ruling or rulemaking or the Legislature could clarify the ambiguity by amending the net metering law.[109] IREC also suggests the same issue as to third-party ownership is present in the laws governing community solar projects in Washington.[110]

Recommendations

While the investor-owned utilities recognize that increasing the cap on customer-generated power for net metering may increase their administrative costs, they also recognize that increasing the cap is not likely to have a significant change in the amount of net metering on the

---

[105] H.B. 1049, An Act relating to net metering of electricity, available at the state legislative web site at http://apps.leg.wa.gov/billinfo/summary.aspx?bill=1049&year=2011.

[106] *See* Comments of the Local Energy Alliance of Washington at 3-4 (July 15, 2011); Comments of Cascade Community Wind at 2 (July 15, 2011).

[107] Comments of the Local Energy Alliance of Washington at 10 (July 15, 2011).

[108] Comments of the Interstate Renewable Energy Council at 4 (July 15, 2011).

[109] *Id*., at 5-7; *see also* September 21, 2011, Memorandum to Jason Coughlin, National Renewable Energy Laboratory, from Thadeus B. Culley and Jason B. Keyes, Fox & Keyes, LLP, re: Permissibility of Third-Party Ownership of Renewable Generation in Washington, filed with the UTC in Docket UE-110667 on September 28, 2011.

[110] Comments of the Interstate Renewable Energy Council at 6-7 (July 15, 2011).

utilities' systems. Given these statements and that the 100-kW cap on net metering is lower than several other states in the Northwest, the Legislature should consider increasing the size of the net metering cap. The cap should be no higher than the net on-site load of the net metering facility, but no larger than the five MW distributed generation cap under the EIA. As the Legislature considers increasing the cap, it should consider the various size limits in laws affecting distributed generation, as shown in Table 1 above, as well as the various goals for the state's electric distribution system. Investor-owned utilities must still maintain the capacity to serve the net-metered customers, so at some level of net metering, there may be increased costs to the utility. The utilities did not define these costs during the inquiry, which may require further inquiry to quantify the costs and benefits of net metering for investor-owned utilities.

While the UTC has jurisdiction under RCW 34.05.240 to issue a declaratory ruling determine the question of whether third-party generators are public utilities in a particular net-metering project, the decision would apply only to investor-owned utilities. If a question arose about the sale of power by a third-party owner to a customer of a public-owned utility, the UTC would have no jurisdiction over the issue. To achieve a statewide policy on the question of third- party ownership, the Legislature could act to address this challenge for promoting distributed generation.

D. Questions Concerning PURPA Contracts

As discussed above in Section II D, PURPA Section 210 directs FERC to prescribe rules requiring electric utilities to purchase electricity from qualifying small power production facilities.[111] PURPA requires state regulatory authorities, such as the UTC, to implement the FERC rules for each electric utility over which it has ratemaking authority.[112] Several issues and questions have arisen outside of this inquiry where small generators request utility purchases under PURPA for resources that also fall under state laws governing renewable resources and distributed generation.

1. Renewable energy credits severable from electricity sales under PURPA

PURPA qualifying facilities that use renewable resources to generate electricity may also produce renewable energy credits. RECs are intangible assets that represent the right to claim the environmental attributes of a renewable resource associated with electricity generated from that facility.[113] RECs may be traded as a bundled product, where the electricity and

---

[111] 16 U.S.C. § 824a-3(a); *see* 18 C.F.R. Part 292.

[112] 16 U.S.C. § 824a-3(f); *see* WAC 480-107.

[113] *Puget Sound Energy, Inc.*, 282 Pub. Util. Rep. (PUR) 4th 303, 306 (Wash. Utils. & Transp. Comm'n 2010); *see* RCW 19.285.030(18).

environmental attributes are sold together to the purchaser, or unbundled, where only the environmental attributes are sold, separate from the power actually generated by a renewable resource. Sales of unbundled RECs may generate significant revenue for the seller.[114]

Under PURPA, a utility is required to purchase the output if the qualifying generator chooses to sell to the utility. Disputes have arisen recently between PURPA qualifying facilities and utilities over whether utility contracts for the purchase of electricity from qualifying facilities transfer ownership of RECs as well. FERC has ruled that ownership of RECs is a matter of state law.[115] Authorities in different states have reached opposite conclusions on this issue, with some ruling that utilities purchasing electricity from PURPA qualifying facilities are also entitled to the RECs, and other states determining they are not entitled to the RECs.[116] Some states have enacted laws providing that RECs belong to the generator of the electricity until voluntarily transferred.[117]

The question of whether REC ownership transfers with the sale of electricity under a PURPA contract, and whether a utility may decline to purchase electricity from a PURPA qualifying facility unless RECs are transferred with the electricity, have not been decided in Washington. These unsettled REC ownership questions may create challenges for small developers during negotiations with the host utility.

Recommendations

As with the issue of third-party ownership under the net metering statute, the UTC has jurisdiction and authority to resolve this question for generators seeking to sell power to an investor-owned utility. If these issues are creating concerns for developers of distributed generation, to the extent they are complicating their efforts to build or install such generation, either a generator or a utility may bring the dispute or question to the UTC. The UTC may

[114] *Puget Sound Energy, Inc.*, 282 Pub. Util. Rep. (PUR) 4th 303, 307 (Wash. Utils. & Transp. Comm'n 2010).

[115] *Am. Ref-Fuel Co.*, 105 FERC ¶ 61,004 (2003), *appeal dismissed sub. Nom Xcel Energy Servs., Inc. v. FERC*, 407 F.3d 1242 (D.C. Cir. 2005); *Idaho Wind Partners 1, LLC*, 136 FERC ¶ 61,174 at P 10 (Sept. 15, 2011) ("the sale and trading of RECs are for the states to determine"); *see Wheelabrator Lisbon, Inc. v. Conn. Dep't of Pub. Util. Control*, 531 F.3d 183 (2d Cir. 2008) (PURPA did not preempt state commission order requiring generators to transfer RECs to utilities).

[116] *See Wheelabrator Lisbon, Inc. v. Dep't of Pub. Util. Control*, 931 A.2d 159 (Conn. 2007) (contract executed in 1991 transferred RECs; noting different outcomes in other states); *In re Ownership of Renewable Energy Certificates*, 913 A.2d 825 (N.J. Super. Ct. App. Div. 2007) (contracts executed between 1986 and 1992 transferred RECs); *ARIPPA v. Pa. Pub. Util. Comm'n*, 966 A.2d 1204 (Pa. Commw. Ct. 2009) (contracts executed before 2005 transferred RECs).

[117] 2011 Or. Laws ch. 248; 73 Pa. Stat. §§1648.2, 1648.3(e)(12) (2008).

address the issue through a binding declaratory order under RCW 34.05.240, or the UTC may resolve the issue on its own initiative by issuing a policy statement.[118]

2. Certainty in the length of PURPA standard offer contracts.

Developers of distributed generation resources seek long-term revenue streams for their electric output as a means of securing financing and ensuring the viability of the project. Certain distributed generation projects, such as dairy digesters, may need lower interest loans to overcome the upfront capital costs of their projects, and the income stream from the sale of electricity is a critical component in the project financing.[119] Investor-owned utility tariffs include published standard PURPA contracts and rates. PSE's standard contract rate under Schedule 91 extends for ten years, while PacifiCorp's contract only extends for five years. UTC rules governing competitive bidding and PURPA standard contracts do not establish a specific contract length, however, the rules governing competitive bidding recognize that a utility may enter into contracts for up to a 20-year term or longer.[120] The rules governing standard offer contracts allow the utility to base its standard offer contract on a combination of factors, including market-based prices.[121]

Proponents of biodigester facilities state that long-term fixed price contracts just below projected retail electricity rates are necessary to encourage technology neutral development of distributed generation resources.[122] Farm Power asserts that a long-term contract should be at least 15 years, with a forward strip fixed price of at least 15 years.[123] Without stable long-term contracts, proponents argue that distributed generation will rarely be built.[124]

Recommendations

The UTC has the authority to review the terms of utility standard contracts to determine if the utilities may make these contracts available under longer terms. The rules governing standard offer contracts allow utilities significant flexibility in determining their avoided costs used in the standard contract and other terms. Establishing a set length of standard offer contracts by rule

---

[118] *See* RCW 34.05.230.

[119] See *Sustainable Energy Trust – Wind Energy and Biodigester Financial Analysis*, prepared for Washington State Housing Finance Commission by David Paul Rosen & Associates, February 5, 2010, Table C-1.

[120] WAC 480-107-075(3).

[121] WAC 480-107-095(2).

[122] Comments of Farm Power Northwest, LLC at 1 (July 15, 2011).

[123] *Id*.

[124] *Id*. at 2.

would remove this flexibility. Further, at the end of the calendar year, the utilities file their annual updated standard offer tariffs with the UTC for review, providing an opportunity for the UTC to evaluate the rates and terms of the contracts. The UTC will review the specific terms in the next annual reviews to determine if longer term contracts may be made available under tariff.

E. Financial Incentives for Distributed Generation

Issues surrounding financial incentives were perhaps the most contentious of any encountered during this inquiry, in part because each interested party has a different view of the costs and benefits derived from new distributed generation projects. Many commenters argue that ratepayer or taxpayer-funded incentives paid to individual owners of distributed resources could be justified easily on the basis of the benefits that distributed generation offers but which are not properly quantified in traditional ratemaking cost allocations. Those claimed benefits include the value of increased energy independence, environmental benefits (or, conversely, prevention of environmental impacts), or local job creation and economic development.[125] Specific concerns about financial incentives for specific technologies are discussed in the appendices dedicated to each technology type (see Appendices 3-7).

1. Washington State Tax Incentives

The State has enacted a number of tax incentives for renewable energy and distributed energy projects. These include reductions in the public utility tax, business and occupations tax (B & O tax) and sales and use taxes. A number of these tax incentives expire in the next ten years.

As discussed in more depth below, electric utilities are allowed a credit against public utility taxes for incentive payments made for electricity produced by community solar projects and customer-generators' renewable energy systems.

---

[125] In considering financial incentives, it is important to note that the Washington Constitution provides that the credit of the state and local governments shall not be given or loaned to any private entity. These provisions prohibit the use of public funds to benefit private interests where the public interest is not primarily served. They do not prohibit the expenditure of funds where there is consideration and lack of donative intent. Further, Washington voters have approved constitutional amendments that permit publicly-owned electric utilities to help property owners finance energy efficiency measures. *See* Wash. Const. art. VIII §§ 5, 7, art. XII § 9; *CLEAN v. State*, 130 Wn.2d 782, 797-801, 928 P.2d 1054, 1061-63 (1996) (legislation establishing a method for financing major league baseball stadium was not an unconstitutional loaning of state credit); *City of Tacoma v. Taxpayers*, 108 Wn.2d 679, 743 P.2d 793 (1987) (city grants to ratepayers for energy efficiency improvements were not unconstitutional gifts of public funds); and Wash. Const. art. VIII § 10. *See generally Seattle Mortgage Co., Inc. v. Unknown Heirs*, 133 Wn. App. 479, 136 P.3d 776 (2006) (Washington Constitution permitted city to loan money to homeowner for conservation measures).

Washington's major business tax is the B & O tax, which is imposed on the gross receipts of business activities conducted within the state. The standard rate for manufacturing activities is 0.484 percent.[126] Beginning in 2005, the Legislature reduced B & O tax rates for manufacturers of solar energy systems. The current reduced rate expires on June 30, 2014.[127]

Washington imposes a tax on retail sales of tangible personal property and services, or alternatively, a tax on their use.[128] In 2009, the Legislature enacted exemptions for the sale and use of certain fuels, equipment, and labor used to generate electricity.[129] The exemptions expire on June 30, 2013. The Joint Legislative Audit and Review Committee recommends that two of the exemptions, those for hog fuel and non-solar equipment, be allowed to expire as scheduled.[130]

Stakeholder Perspectives

As mentioned above, PacifiCorp argues strongly that no changes are required to accommodate more distributed energy because the existing net metering and interconnection rules are flexible enough to allow distributed energy resources to interconnect, and expenses related to interconnection between the customer-generator and utility are properly allocated.[131] The company notes that policymakers are ultimately responsible for determining if and when subsidies for distributed energy development are desirable. The company further states that incentives and subsidies are "an explicit admission that these energy sources are not cost effective for customers." Therefore, if policymakers determine that social, economic, and environmental goals for producing these energy sources (beyond cost) require subsidies, then the most "effective and fair approach" would be a public subsidy such as the Washington community solar tax credit or the federal renewable energy production tax credit.[132]

---

[126] RCW 82.04.240.

[127] RCW 82.04.294.

[128] RCW 82.08.020 (retail sales tax); RCW 82.12.020 (use tax).

[129] RCW 82.08.956, RCW 82.12.956 (sales and use tax exemptions for hog fuel used to produce electricity); RCW 82.08.957, RCW 82.12.957 (sales and use tax exemptions for forest derived biomass used to produce electricity); RCW 82.08.962, RCW 82.12.962 (partial sales and use tax exemptions for equipment generating electricity from certain fuels, and labor to install it); RCW 82.08.963, RCW 82.12.963 (sales and use tax exemptions for equipment generating electricity using solar energy, and labor to install it).

[130] State of Washington, Joint Legislative Audit & Review Committee (JLARC), *2011 Tax Preference Performance Reviews*, *Preliminary Report* (Revised August 1, 2011), at 69-76, 195-207 (available at http://www.leg.wa.gov/JLARC/AuditAndStudyReports/2011/Documents/2011TaxPreferencesPreliminary.pdf).

[131] Comments of PacifiCorp at 5 (July 15, 2011).

[132] *Id*. at 14-15.

Finally, PSE states that financial incentives should be targeted at specific technologies, because technology-neutral incentives tend to draw investment toward the most lucrative returns.[133] PSE echoed the comments of the other two electric IOUs in arguing that it would most favor subsidies or incentives paid directly by the state or federal government, "do not burden the shareholders or ratepayers of utility companies," and do not "result in one site or type of utility having a competitive advantage over other utilities."[134]

Recommendations

In addition to the incentives discussed above, we recognize that net metering provides a type of incentive for individual consumers because it shifts costs from the individual ratepayer to the utility, and ultimately to the other ratepayers of that utility, due to the need to maintain sufficient capacity to meet that individual customer's load while his or her net metered system is not generating electricity. The provision in the EIA that allows distributed generation projects to qualify for double RECs is also a financial incentive, which promotes projects under five MW.

We recommend a comprehensive review of the financial incentives promoting distributed generation. The review should consider the costs and benefits of net metering, Washington's existing cost recovery mechanism, other tax credits, reductions, and exemptions, and the provision of double RECs for renewable resource generation projects under five MW. It should address such questions as: Does doubling the value of distributed generation projects weaken the renewable portfolio standard by diluting the value of a single REC? What benefits are provided by projects with five-MW capacity or less that are not provided by projects over five MW? Should efficiency measures receive similar incentives?[135] Ultimately, the review should determine whether the incentives are consistent with one another and work together in meeting the state's goals for the electric distribution system and promoting cost-effective distributed generation.

2. Cost Recovery Incentive for Customer-Generated Renewable Energy Systems and Community Solar Projects and Feed-In Tariffs

In 2005, the Legislature created an investment cost-recovery mechanism for customer-generated renewable energy systems, and in 2009 and 2010, expanded it to community solar.[136] Under

---

[133] Comments of Puget Sound Energy at 4 (July 15, 2011).

[134] *Id*. at 14.

[135] The EIA provides no RECs for passive generation systems, such as solar thermal water heaters, even if the savings potential for solar water heaters out-paces the potential for electricity generation from conventional solar photovoltaic systems because of its lower production cost.

[136] RCW 82.16.110 - .140.

these incentives, a "renewable energy system" means a solar energy system, an anaerobic digester, or a wind generator used for producing electricity.[137] An individual, business, or local government purchasing an eligible system in Washington can apply for an incentive payment from the electric utility serving the applicant. Incentive payments are based on kilowatt-hours produced, fuel source, and the place of manufacture of system components. An electric utility providing incentive payments is allowed a credit against its public utility taxes, under rules adopted by the Washington Department of Revenue.[138] This mechanism is similar to a feed-in tariff, but costs are borne by taxpayers rather than ratepayers. The cost recovery incentive program, and the right to earn tax credits, expires on June 30, 2020.[139]

A "feed-in tariff" requires utilities to purchase power at wholesale from certain types of suppliers, such as renewable energy facilities, where the rate is higher than the utilities' avoided cost and near the renewable energy facilities' production costs. Some European countries have adopted feed-in tariffs (FITs) and such tariffs have attracted the interest of state policy makers in the United States as a possible way to promote the development of renewable energy projects as well as to stimulate local manufacturing of renewable energy facilities.[140] However, questions have arisen about the extent to which the Federal Power Act or PURPA Section 210 may limit state authority to establish feed-in tariffs.

In 2007, the California Public Utilities Commission (CPUC) adopted a feed-in tariff for small facilities that met requirements set by California law. When utilities challenged it before FERC, FERC agreed that the CPUC feed-in tariff was preempted under the Federal Power Act as impermissible wholesale rate-setting.[141] FERC recognized, however, that states have a path under Section 210 of PURPA to set avoided cost rates for electric utility purchases from qualifying facilities. FERC suggested that when state regulators determine the costs that are avoided when electric utilities purchase electricity from a qualifying facility they may take into account the need for utilities to acquire renewable resources to comply with state mandates, such as renewable portfolio standards.[142]

---

[137] RCW 82.16.110(7).

[138] WAC 458-20-273.

[139] RCW 82.16.130.

[140] *See generally* Brian Jansen, *Community Wind Power: Making More Americans Energy Producers through Feed-In Tariffs*, 20 Kan. J. L. & Pub. Pol'y 329 (2011).

[141] *Cal. Pub. Utils. Comm'n*, 132 FERC ¶ 61,047 (2010).

[142] *Cal. Pub. Utils. Comm'n*, 133 FERC ¶ 61,059 (2010), 134 FERC ¶ 61,044 (2011). Note that S. 1491 (the "PURPA PLUS Act"), currently pending in the 112th Congress, would permit state authorities to set rates for qualifying facilities of not more than two megawatts capacity without regard to avoided costs.

In response, the CPUC established the Renewable Auction Mechanism (RAM) requiring utilities to purchase certain amounts of renewable energy through periodic auctions conducted by the utilities. In the auctions, the utility may choose the lowest bidders of renewable energy projects to meet its acquisition requirements. The RAM functions like an RPS carve-out by requiring acquisition of certain types of renewables. Unlike FIT mechanisms that pay one set price to all developers, regardless of how much their cost of production is under the FIT price, the utilities using the RAM pick the lowest cost producer within the generation technology category in the auction. This mechanism, according to the CPUC, is not preempted by the Federal Power Act, although it has not been reviewed by FERC or contested in court.[143]

Stakeholder Perspectives

Avista expresses some concern that utility-based subsidies are already costly, and that significant cost-shifts might occur under utility-based subsidies that are designed to reduce the cost of distributed generation to a utility's cost-of-service level.[144] The company argues that a feed-in tariff may be the "most costly form of utility-based subsidy in that it conceptually requires the utility to pay a rate which guarantees that the developer or generator will not only recover all of its investment in a resource that may not otherwise be cost-effective, but also a profit."[145] The company cautioned that if the goal of a distributed generation subsidy is environmental, such as to reduce greenhouse gas emissions, the subsidy may be redundant to existing regulations requiring electric utilities to reduce emissions (in cases where electricity is generated from fossil fuels) and to acquire more efficient generation technologies. It argues that "more significant and cost-effective emission reductions can be achieved with central station generation than from measures to encourage piece-meal development of distributed generation."[146]

Several commenters support a feed-in tariff or a Clean Energy Standard Offer (Standard Offer) program. WALEA describes FITs as "the world's most effective mechanism for encouraging distributed generation," but stated that a well-designed cost-recovery incentive combined with ensuring "fair market access" could have the same effect as an FIT.[147] CPG states that Standard Offers and FIT incentive payments are an effective way to increase development of distributed

[143] Decision Adopting the Renewable Auction Mechanism, Decision 10-12-048 at 18-19 (Cal. Pub. Utils. Comm'n, Dec. 16, 2010)

[144] As an illustration, if a utility's cost to serve the customer expressed in price per kWh is $ 0.07 and the levelized cost of a household photovoltaic system is $ 0.21 per kWh, then the FIT subsidy would be $ 0.14 per kWh. The utility would likely seek to recover the difference from all ratepayers through a general rate case due to the increase in its power costs.

[145] Comments of Avista at 5 (July 15, 2011).

[146] *Id*. at 17.

[147] Comments of the Local Energy Alliance of Washington at 4 (July 15, 2011).

generation projects, and states that rates should be based on system operation improvements and environmental impact rather than supporting a specific type of technology.[148] NWEC notes that FITs have "proven to be highly effective in incenting distributed solar across the globe," and that a FIT program does not need to focus solely on solar photovoltaics.[149]

Recommendations

The California RAM auction has the advantage of allowing for the least cost purchase of generation from certain types of technology classes or sizes. However, in the effort to promote distributed generation or certain renewable technologies, such an auction likely would increase rates more than non-distributed generation or other lower cost renewable technologies. The EIA requirements are beginning to impact rates at a time of tempered electric fuel costs; adding a higher cost resource will put additional upward pressure on rates.

With regard to new incentives, UTC requested comments from interested parties about the solar feed-in tariff recently piloted in Oregon.[150] Many commenters note that the incentive level was set too high in the program, first ranging from $0.55 to $0.65 per kWh and later reduced to $0.356 to $0.421, as evidenced by the volume and urgency of customer interest.[151]

As discussed in Section I, we recommend a comprehensive review of Washington's financial incentives, including the cost recovery incentive. Generally speaking, however, we do not view a feed-in tariff as the optimal approach at this time to encourage development of distributed generation. Washington's current cost recovery incentive avoids potential challenges in complying with PURPA and does not add to the upward pressure on retail electric rates (though it does decrease tax revenue). Consideration should be given to stakeholders' assertions that extending the cost recovery incentive beyond 2020 would encourage more distributed generation now, because it would provide greater certainty to developers who are considering a long-term investment.

---

[148] Comments of Cascade Power Group at 4 (July 15, 2011).

[149] Comments of Renewable Northwest Project and Northwest Energy Coalition at 3 (July 15, 2011).

[150] Notice of Opportunity to File Written Comments, Question B.3; *Volumetric Incentive Rates for Solar Photovoltaic Energy Systems*, 281 Pub. Util. Rep. (PUR) 4th 421 (Or. Pub. Util. Comm'n 2010) (establishing pilot program).

[151] *See* Comments of Renewable Northwest Project and Northwest Energy Coalition at 11 (July 15, 2011); Comments of Puget Sound Energy at 11 (July 15, 2011).

IV. Conclusion and Recommendations

The House Technology, Energy and Communications Committee requested the UTC to contribute to its interim project on distributed energy by providing "background information and detailed discussion to the TEC Committee and the Legislature of the available options to encourage the development of cost-effective distributed generation in areas served by investor-owned utilities, as well as the opportunities and challenges facing investor-owned utilities and their ratepayers in developing distributed generation in this state."[152]

The comments and materials the UTC received from interested stakeholders and through technical assistance from the National Renewable Energy Laboratory provided a wealth of information and data about distributed generation.[153] These materials provided a general sense of the cost effectiveness of particular resource technologies as distributed generation. This discussion is included in Appendices 3 through 7 of the report. After reviewing all of the information, however, it is clear that a more focused evaluation of the costs and benefits of distributed generation to investor-owned utility systems is necessary before the UTC can provide guidance to the Committee and the Legislature about what types distributed generation would be cost-effective in IOU service areas. One of our recommendations to the Committee, therefore, is that the Legislature request a group of utilities, representative of utility systems in Washington, to perform initial cost/benefit analyses of distributed generation resources assuming different levels of system peak load (e.g., .25, .50 and 1.0 percent). The cost/benefit analyses, while preliminary, would attempt to monetize the system benefits associated with the installation of technically feasible distributed generation technologies at the various levels and compare these benefits to current or projected system operating costs. The information would provide legislators and other decision-makers with better information about how to shape state policy governing distributed generation.

In this report, the UTC provides the Committee and the Legislature an overview of the laws and rules governing distributed generation, as well as a detailed description of the potential for specific renewable resources as distributed generation. Based on the comments the UTC received from interested stakeholders in writing, as well as the discussions during the workshop held on July 25, the UTC identified several actions the Legislature and the agency could take to address challenges that might impede or complicate the promotion of distributed generation in Washington State.

---

[152] June 9, 2011, letter from Representative Eddy to Jeffrey Goltz, attached as Appendix 1.

[153] A list of key sources concerning distributed generation, generally, and specific topics is included in Appendix 8 of this report.

These recommendations, discussed in detail above, include the following:

- **Amend RCW 80.60, Net Metering, to increase the cap from 100 kW and clarify whether third-party ownership of generation facilities results in the third-party owner being an electric company subject to UTC regulation.** This occurs in circumstances where the third party develops and installs the generating resource on a utility customer's property, and sells the electric output to the customer, who engages in net metering with the utility.

- **Amend definitions in the Energy Independence Act, RCW 19.285.030,** of "eligible renewable resource" to include combined heat and power resources, and "distributed generation" to clarify the meaning of the term "generating capacity."

- **Review comprehensively the existing financial incentives for distributed generation**, e.g., cost recovery mechanisms, tax credits, tax reductions and exemptions, net metering, and multiple RECs to determine whether the incentives are consistent and work together in promoting cost-effective distributed generation.

- **Gather Information to Analyze the Costs and Benefits of Varying Levels of Distributed Generation.** Request a group of utilities, representative of utility systems in Washington, to perform initial cost/benefit analyses of distributed generation resources assuming different levels of system peak load (e.g., .25, .50 and 1.0 percent) to provide legislators and other decision-makers with better information to shape state policies.

Certain actions are appropriate for the UTC to address through its current statutory authority. These recommendations include:

- **Review Interconnection Rules (WAC 480-108).** Initiate a rulemaking inquiry to determine whether to amend certain rules governing the interconnection of generation facilities with utility electric systems, including requirements for external disconnect switches and insurance, and whether to adopt unique interconnection rules for generators between 300 kW and 20 megawatts (MW).

- **Clarify ownership of RECs under PURPA contracts** between developers and utilities through petitions for declaratory ruling, policy statements or rulemaking.

- **Provide greater certainty for developers of distributed generation through longer duration standard offer PURPA contracts** established under utility tariffs, such as Puget Sound Energy's Schedule 91.

Given the current budget pressures in Washington, the UTC limits its recommendations to actions that will support distributed generation without unreasonably increasing costs or other burdens on ratepayers or taxpayers, or requiring additional state financial support. These recommendations offer opportunities to remove requirements that may be overly burdensome, or that may no longer be necessary. The recommendations also focus on improving the efficiency of utility services to distributed generation developers and efficiency and clarity in the laws and rules governing distributed generation. Further, the recommendations aim to gain a better understanding of the role of distributed generation in how utilities provide service to their customers, and the costs and benefits to the utilities of incorporating distributed generation in their electric system.