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VIA ELECTRONIC FILING

Washington Utilities and Transportation Commission
1300 S. Evergreen Park Drive, S.W.
P.O. Box 47250
Olympia, Washington 98504-7250

Attention: David W. Danner
Executive Director and Secretary

RE: Docket No. UE-110667 – Comments
Study of the Potential for Distributed Energy in Washington State

PacifiCorp d.b.a. Pacific Power & Light Company (PacifiCorp or Company) submits the following comments in accordance with the Washington Utilities and Transportation Commission's (Commission) Notice of Opportunity to File Written Comments (Notice) issued in Docket UE-110667 on June 24, 2011.

A. GENERAL – CROSS-CUTTING ISSUES

1. What is the scope of current and anticipated distributed energy in the service territories of Washington's investor-owned utilities, including technology type, size and capacity; distribution across service territory; application of feed-in tariffs or net-metering; and any other relevant information? For each technology, what is its total technical resource potential (in contrast to the present, economically viable potential)? Is it concentrated within the state?

Response: For current distributed energy resources in PacifiCorp's six-state service territory, please refer to Attachments A and B; the information is provided by state and by technology type. Attachment A provides a list of net metering customers as of July 14, 2011. Attachment B provides a list of existing distributed energy resources, with a capacity of 20 megawatts (MW) or less connected to PacifiCorp's distribution or transmission system as of July 14, 2011[1].

The attachments show that PacifiCorp's Washington service territory includes 25.5 MW of net metering customers and distributed energy resources connected to either PacifiCorp's distribution or transmission system. On a total company basis, the current capacity associated with net metering customers and distributed energy resources connected to PacifiCorp's distribution or transmission system is 349.0 MW. Washington net metering customers are primarily solar projects totaling 0.26 MW. Washington distributed energy resources are primarily small hydro facilities totaling 24.0 MW, and one 1.2 MW biogas (methane) facility.

[1] Attachment B excludes net metering customers' projects provided in Attachment A.

From a future resource potential perspective, a study for PacifiCorp's 2011 integrated resource plan (IRP), estimated achievable additional installed capacity potential of distributed energy technologies for Washington at 48.8 MW by 2030. On a total company basis, the estimated potential is 426.3 MW by 2030. For this particular study, the analysis focused on customer-sited generation, primarily in residential and small commercial facilities of 5 MW or less. The following table shows the installed capacity potential by technology type for PacifiCorp's Washington service territory and on a total company basis.

Installed Capacity Potential by Technology Type
PacifiCorp's Washington Service Territory and on a Total Company Basis

Technology Type	**Potential Installed Capacity by 2030 (MW)**	
	Washington	**Total Company Basis**
Reciprocating Engine	2.2	33.2
Micro Turbine	0.3	4.5
Fuel Cell	0.02	2.5
Gas Turbine	0.02	2.9
Industrial Biomass	16.9	215.9
Anaerobic Digesters	0.3	2.9
Photovoltaic	2.4	55.9
Solar Water Heaters	25.8	98.2
Solar Attic Fans	0.5	10.3
Total	**48.8**	**426.3**

PacifiCorp's 2011 IRP preferred portfolio includes 52 MW of combined heat and power (CHP) resources assumed to be acquired predominately as Public Utilities Regulatory Policies Act (PURPA) qualifying facilities (QFs), as well as 30 MW of solar hot water heating resources and an additional 10 MW of Oregon rooftop solar resources acquired through a state-mandated solar incentive program. Expectations for future distributed energy systems in Washington and other states is highly unpredictable due to the dependency on factors outside of the utilities' control such as uncertain government financial incentives and environmental regulations, economic/market conditions, electricity prices, fuel prices, and location-specific project attributes.

2. **What is, or what is anticipated to be, the overall cost of integrating distributed energy resources to investor-owned utilities?**

   Response: PacifiCorp has not developed an estimate of the overall cost of integrating distributed energy resources.

3. **Describe the incentives paid by or through investor owned utilities. How much is paid annually for each technology?**

   Response: PacifiCorp currently offers incentive programs in four of the six states in which it operates.

   California Solar Incentive Program - The California Solar Incentive Program began accepting applications on July 1, 2011. The program is designed to provide an Expected Performance Based Incentive (EPBI). This means that the incentive will be paid after interconnection based on the expected performance of the system as it is installed. In order to compute the incentive a computer program analyzes the components installed, the solar factor at the installed location, and the tilt and azimuth of the installed system. After the system is successfully interconnected and field verified the incentive will be paid in one payment. In the first week of accepting applications, PacifiCorp received 15 non-residential applications with a nameplate capacity of 1,014 kilowatts (kW) and 31 residential applications with a nameplate capacity of 171 kW.

The program is designed to provide a higher incentive initially, decreasing over the life of the program. The incentive started at $2.00 per watt, with the incentive decreasing by 25 percent through each of the next six predetermined steps. Tax exempt entities will receive an additional $0.75 per watt, to help offset the inability to receive federal tax rebates on their solar installation.

Table 1: Budget, Adopted Incentive Structure (Dollars per watt) and Capacity Allocations per Step

Step	Total kW Installed per Step	Residential kW 33%	Commercial / Tax Exempt kW 67%	Residential / Commercial Incentives ($/watt)	Tax Exempt Incentive ($/watt)	Incentive Budget	Administrative Budget	Total Budget
1	448	148	300	$2.00	$2.75	$917,692	$201,900	$1,119,592
2	483	160	323	$1.50	$2.23	$749,701	$164,250	$913,951
3	520	172	348	$1.13	$1.88	$611,258	$164,250	$775,508
4	467	154	313	$0.84	$1.59	$417,498	$164,250	$581,748
5	501	165	336	$0.63	$1.38	$342,214	$0	$342,214
6	540	178	362	$0.47	$1.22	$283,424	$0	$283,424
7	583	192	391	$0.36	$1.11	$236,819	$0	$236,819
Total	**3542**	**1169**	**2373**			**$3,558,606**	**$646,950**	**$4,253,256**

Oregon Solar Incentive Program - The Oregon Solar Incentive Program is a pilot demonstration program approved by the Oregon Legislature which encourages the installation of 25 MW within the investor-owned utilities' service territories. PacifiCorp's Oregon service territory allocation from this program is 9.8 MW. The program began in July 2010 and is designed to operate as a performance based incentive where customer generators receive a fixed incentive for each kilowatt-hour (kWh) produced for 15 years after the installation of the system.

The program split the available capacity into three segments based on the size of the system. Small systems of 10 kW and below were allotted 48 percent of the capacity. Medium systems sized between 10 and 100 kW were allotted 32 percent of available capacity. Large systems sized between 100 and 500 kW were given 20 percent of the available capacity. These allotments were then spread over eight capacity reservation windows opened on July 1 and October 1 during the first year and April 1 and October 1 the following three years of the program.

In order to avoid conflict with the Federal Energy Regulatory Commission (FERC), the small and medium segments of the incentive were designed as a modified net metering program. The incentive payments are only paid for generation up to the total usage at the facility. The Public Utility Commission of Oregon (OPUC) believes that by capping the incentive payments at a level equivalent to the usage at the facility, the transaction of paying the incentive would not be construed as a sale of power at above avoided cost rates, and would thus not be in conflict with FERC authority[2].

The large system allocation was distributed through a different process. The available capacity is distributed through a competitive bidding process or request for proposals (RFP) with the allocation going to the lowest bidders. This is considered a market-based rate and avoids FERC conflicts. Customers selected to participate through the large RFP are required to certify that they have received market based rate authority from FERC in order to sell the production from their solar systems.

The rate paid for generation in the Oregon Solar Incentive program began at $0.65 per kWh, is varied based on geographic regions, and has been reduced during each subsequent allocation period. The incentive levels are more thoroughly addressed in Section B, Question 3 (*Distributed Solar*).

Since the Oregon Solar Incentive Program is an ongoing performance based incentive the total costs of the incentive can only be estimated. As shown below, as the program ramps up and more capacity is installed, the estimated costs for the program will rise dramatically. The table below shows the actual incentive paid for the first year of the program, an estimate of the yearly incentives in years 5 through 16 when the capacity is fully installed, and an estimate of total program incentive costs.

Oregon Solar Incentive Program
Actual and Estimated Program Incentive Costs

Time Frame	kWh Subsidized	Total Cost ($)
First year (actual) July 1 2010 through July 1 2011	295,612	$193,975.40 (actual)
Years 5-16 (estimate)	15,109,275	$5,769,729 per year
Program Total (estimate)	**226,640,436**	**$86,546,692**

Utah Solar Incentive Program - PacifiCorp is in the final stages of completing the Utah Solar Incentive Program. This four year program began in August 2007 and offered a buy down incentive paid on the direct current (DC) nameplate capacity of the installed photovoltaic system after completion of system interconnection. A residential incentive was limited to the first 3 kW of an installation. Non-residential customers could receive an incentive on the first 15 kW of an installed photovoltaic system. Incentive funds were based on the number of kW allotted for the year resulting in: approximately 72 kW residential and 58 kW of non-residential installations. The incentive was set at $2.00 per watt of installed capacity in the first three years of the program, and was decreased to $1.55 per watt during the final year of the program.

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[2] Public Utility Commission of Oregon, Order 10-198, pg 11

Utah Solar Incentive Program
Actual and Estimated Program Incentive Costs

Year	Incentive per watt ($)	Installed capacity (kW)	Cost ($)
2007	$2.00	57.36	$114,760
2008	$2.00	125.38	$250,767
2009	$2.00	111.017	$222,034
2010	$2.00	110.812	$221,590
2011	$1.55	125.60	$194,680 (Estimated*)
Total		**530.169**	**$1,003,831***

Washington Renewable Energy System Cost Recovery - PacifiCorp manages the Washington Renewable Energy System Cost Recovery program for the Washington Department of Revenue in the service territory. Customers who install solar, wind or anaerobic digestion facilities are eligible to receive this performance based incentive. The amount of the incentive is based on the amount of kWh generated and an incentive amount which fluctuates based on the origin of the equipment and the nature of the customer generator. The table below provides the number of participants and incentive amount for calendar years 2009 and 2010.

Washington Renewable Energy System Cost Recovery
Incentive Costs

Year	Number of Participants	Incentive Amount ($)
2009	3	$1,231.35
2010	12	$9,342.56

4. **Are there changes in state statutes or rules that would encourage technology-neutral development of distributed energy generally, such as changes to financial incentives? For example, would current interconnection standards need to be changed to accommodate more distributed energy or to accommodate different distributed energy technologies? Why?**

   Response: PacifiCorp believes that no changes are required to accommodate more distributed energy. PacifiCorp believes that the net metering and interconnection rules in Washington are flexible enough to allow the interconnection of distributed energy resources and properly allocate the expenses related to interconnection between the customer generator and the utility.

5. **What storage options exist that could be used to help integrate distributed energy into the electric grid?**

   Response: PacifiCorp has evaluated a number of energy storage options in the context of integrated resource planning. These options include advanced batteries, pumped hydro, compressed air energy storage, and solid oxide fuel cells. However, the Company has yet to evaluate the commercial and operating viability of such resource options for supporting specific applications, such as distributed energy integration. A detailed study to investigate storage technologies is planned for 2012.

6. **Do distributed energy technologies impact investor-owned utility rates currently? If so, please describe how and whether rate impacts affect certain customer classes more than others. How might future rates be impacted?**

Response: Yes. The most obvious example of distributed energy technologies impact on rates is in the recovery of costs related to incentive programs. PacifiCorp recovers the costs associated with each state's incentive programs from the customers in that state, i.e., the costs associated with the incentive programs in Oregon are recovered from customers in Oregon. The same applies to California and Utah. The only exception is in Washington where the Department of Revenue gives PacifiCorp a tax credit for the incentives paid out. The California Solar Incentive Program does exempt low-income customers who are enrolled in the California Alternate Rates for Energy (CARE) bill discount program from the cost of the solar program. However, in general these costs are recovered across all rate classes.

There is also the added impact on rates of higher administrative costs incurred in the management of the net metering and interconnection programs. For net metering alone headcount has been specifically added by the Company to manage the interconnection review, billing and regulatory requirements associated with net metering and the related incentive programs. This does not consider the impact on field personnel, metering staff, and field engineers who are brought in during the interconnection process.

An additional impact on rates is the potential need for significant distribution and/or transmission system upgrades to accommodate numerous interconnections as well as increased maintenance requirements. Each state apportions these costs differently with some costs falling on the customer generator while others are socialized and spread over the remaining customers. Washington interconnection rules require the interconnection customer to bear most of the costs associated with interconnection and system upgrade costs.

7. **Do distributed energy technologies meet winter peaking needs for investor-owned utilities? Can distributed energy technologies serve base load capacity? Which distributed energy technologies serve primarily as an hour-ahead or day-ahead energy supply? How can each of the distributed energy technologies and fuel sources contribute to meeting utility peak load needs?**

Response: PacifiCorp believes that distributed energy technologies can help meet winter peaking needs. However, for resource planning purposes, the focus has been on addressing summer peaking needs. Only industrial biomass/waste-fired boilers are comparable to base load utility capacity, with capacity factors in the 90 to 95 percent range. Characterization of distributed energy technologies as an hour-ahead or day-ahead supply is contingent on the supporting infrastructure (i.e., communications, control, and metering), as well as the dispatchability of the technologies. Only dispatchable distributed generation or hybrid distributed generation/storage systems are capable of providing significant and dependable peak load serving capabilities.

8. If rates or incentives are established at the state level, would it violate or conflict with the federal law provisions in PURPA and the Federal Power Act? For example, if the Commission interprets PURPA to establish a feed-in tariff at the state level, is the Commission obligated by federal law to establish a rate that does not exceed avoided cost?

Response: Whether or not rates or incentives established at the state level violate or conflict with federal law will hinge in large part on whether such rates or incentives exceed the utility's avoided cost, as that term is defined by PURPA. FERC has held that certain feed-in tariffs and incentive programs are not preempted by the Federal Power Act, PURPA or FERC regulations as long as: 1) the relevant generator is a QF pursuant to PURPA; and 2) the rate or incentive established does not exceed the avoided cost of the purchasing utility.[3] Therefore, under current federal law, the Commission may not establish a rate that exceeds avoided costs. A state program that results in the setting of non-QF wholesale rates or establishes purchase obligations for FERC-jurisdictional entities is likely to be preempted by federal law. FERC's authority under the Federal Power Act includes the exclusive jurisdiction to regulate the rates, terms and conditions of sales for resale of electric energy in interstate commerce by public utilities.[4]

9. Certain statutes and Commission rules require the UTC to review resource acquisition pursuant to least cost planning. Would pursuing distributed energy conflict with those rules due to the nascent state of technology development and current cost to implement? How far, if at all, should the state depart from least cost planning principles and rules?

Response: Pursuing distributed energy will not directly conflict with current resource acquisition review requirements. PacifiCorp currently includes distributed energy resources in its resource portfolio assessments conducted for integrated resource planning, and continues to address challenges in evaluating such resources in a consistent and comparable manner with respect to other resource types. If the Washington State Legislature and the Commission wish to encourage the development of distributed energy projects that far exceed least cost, it may need to modify its statutes and its resource acquisition review requirements to ensure the implementation of these projects.

10. If the Commission were to change the avoided cost methodology for certain types of renewable resources, what criteria should we take into account as we do this?

Response: The following criteria should be considered when modifying the avoided cost methodology:

- Impact of renewable portfolio standards (RPS), consistent with PURPA and FERC precedent. FERC clarified that the avoided cost rate may not include a "bonus" or "adder" above avoided cost to provide compensation for environmental externalities, although such costs can be included if they are real costs that would be incurred by the utility.

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[3] 134 FERC ¶ 61,040 at P 5 (2011)

[4] 132 FERC ¶ 61, 047 at P 64; *See also Midwest Power Systems*, 78 FERC ¶ 61,06 (1997).

- Renewable resource sufficiency/deficiency timing as identified in PacifiCorp's IRP.
- Avoided cost should be based on the estimated cost of the next avoidable renewable resource identified in PacifiCorp's IRP preferred portfolio, and these costs should be used at the conclusion of the resource sufficiency period.
- Ownership of the environmental attributes (i.e., renewable energy certificates (REC), etc).
- Integration cost of the resource.

Should there be a total cap on the amount of resources to be acquired in this manner, and, if so, state-wide or by utility?

Response: No. PacifiCorp has an obligation to purchase the net output from PURPA projects regardless of resource type. The acquisition of renewable resources under PURPA is based on IRP resource needs and timing, driven by cost-effectiveness and risk mitigation.

Should there be a carve-out for certain technologies that are in a more nascent stage of development now, or should commercially available and emerging technologies be treated equally?

Response: No. PacifiCorp does not support carve-outs for developing technology. PURPA does not allow the utility to discriminate among technology if the technology qualifies as a renewable resource under PURPA. Since QF resources are designated to serve network load, it is prudent for the utility to ensure that the project, regardless of technology, becomes operational to supply customer loads through an upfront review of the project and through contract terms that provide risk mitigation and credit support in the event of default.

11. Other policy incentives, both at the state and federal level, already exist for certain types of renewable resources, such as federal grants and state or federal tax benefits. How should these incentives be considered in to the calculation of avoided cost?

Response: Consistent with PacifiCorp's IRP, the Company applies known federal tax credits or grants to a qualified renewable resource that is used as the proxy, depending on the installation date.

12. For both capacity and energy, how does the current cost of building distributed energy technology compare with other available resources?

Response: Conventional thermal-based distributed generation, such as reciprocating engines and industrial biomass-fueled boilers are generally cost-effective with respect to other supply-side resources for both capacity and energy. Renewable-based distributed energy resources, such as rooftop photovoltaic installations, are not. This conclusion is drawn from the evaluation of generic resources that have been modeled on a system-wide basis, as well as the calculation of per MWh total resource costs using PacifiCorp's technology characterization information.

13. What marginal costs are associated with the interconnection requirements for the connection of distributed energy systems? Are those costs material, and how should the costs be recovered (socialized or born by customer-owners of distributed resources)?

Response: For PURPA QFs, all interconnection costs are paid for by the interconnection customer. Interconnection costs are all costs associated with interconnection and service of a customer's on-site generating facility (on the customer's premises) connected to PacifiCorp's distribution or transmission system. Interconnection costs include all reasonable costs, charges, and expenses (including all reasonable internal costs and overheads) incurred by PacifiCorp in the design, construction, installation, modification, testing, regulation, approval, inspection and commissioning of the desired interconnection. The total amount of the interconnection costs can vary significantly based on the specifics of the interconnection required for service.

14. Should the current statutory restrictions on the size of distributed energy resources be changed? If so, please explain the reasons for the suggested change.

Response: An argument could be made that the net metering cap could be raised to allow larger commercial facilities to participate more fully in net metering. The current cap of 100 kW is one of the lowest among PacifiCorp's six-state service territory. As renewable technologies have become more affordable, the Company has witnessed an increase of larger projects in other states, in many cases initiated by government entities. To date, the Company has not been faced with the need to refuse a project due the cap in the Washington service territory.

15. Can each distributed energy resource be used to support emergency management practices in addition to electricity generation?

Response: In order to respond to this question, PacifiCorp would need to better understand the Commission's definition of emergency management practices.

16. Are there other technologies we should consider in addition to wind, solar, hydrokinetic, biomass, and biogas? If so, please identify the technology, the state of development and likelihood of adoption.

Response: In each of the six states that PacifiCorp serves, there are slightly different technologies incorporated in the net metering and interconnection rules (see Attachments A and B).

Of the 2,846 net metering projects interconnected to PacifiCorp's system, the breakdown of existing technology types is provided in the table below. For the near future, it is likely that the primary technologies will continue to be solar and wind.

Existing Net Metering Projects
Percentage by Technology Type
(per Attachment A)

Technology Type	Percentage of Total Projects (%)
Solar	92.6%
Wind	6.2%
Solar/Wind	0.9%
Hydro	0.2%
plus 2 small projects from other technologies (biomass and fuel cell)	0.1%
Total	**100%**

Of the 90 projects connected to PacifiCorp's system at the distribution or transmission level, the breakdown of existing technology types is provided in the table below.

Existing Distribution and Transmission Level Projects
Percentage by Technology Type
(per Attachment B)

Technology Type	Percentage of Total Projects (%)
Hydro	54%
Wind	17%
Biogas	8%
Biomass	8%
Natural Gas	6%
Landfill Gas	3%
CHP	2%
Geothermal	1%
Solar	1%
Total	**100%**

B. TECHNOLOGY-SPECIFIC ISSUES

Distributed Solar

1. **Not including the photovoltaic solar panels themselves, what is the cost of installation on a unit basis of solar panels in distributed energy applications? How does this compare to the per-unit cost of installation for utility scale applications?**
2. **Is the integration of the variable output of photovoltaic power production made easier or less expensive if it is distributed versus central plant photovoltaic production?**
3. **Are there lessons learned from Oregon's tariff subsidies for solar installations? Is there a calculated subsidy per kWh for the Oregon program?**
4. **Given the variety of tax and other financial incentives for solar manufacturers and consumers, are additional incentives needed?**

Response:

Installed Costs - PacifiCorp collected cost data regarding the installation of solar systems in distributed energy applications during the development and implementation of the different PacifiCorp solar programs. The data is only of limited use as it has been drawn from different geographic locations, with limited sample sizes, during different time periods, but tends to show a steep decline in the cost of solar installations.

California Solar Incentive Program: As part of the development of the California Solar Incentive Program, PacifiCorp conducted research and found that the average cost of solar installation was $8.07 per watt at the time in Northern California. This installation cost was based on an analysis of 238 solar projects affiliated with the California Solar Initiative installed in 2010 in counties just south of PacifiCorp's Californian service territory. Actual results from projects directly affiliated with the California Solar Incentive Program are not available as the program began on July 1, 2011.

Oregon Solar Incentive Program: Having recently completed the first year of the Oregon Solar Incentive Program, the average installed cost is significantly lower than those found in the other programs. Currently the average installed cost for solar systems is $6.44 per watt. This steep decline in actual installed costs in the Oregon Solar Incentive Program is reinforced by testimony from solar installers in a recent Oregon Solar Workshop which anecdotally referenced prices for projects between $5.50 and $6.00 as the standard selling point for distributed installation.

Utah Solar Incentive Program: In Utah, PacifiCorp has been collecting data on the costs of installations since late 2007, the first year of the incentive program. In 2008 and 2009, the average cost of solar installations remained constant with an average installed cost of $9.73 and $9.69 per watt respectively. In 2010, the average cost of installation dropped to $8.64 per watt. Data is not yet available for the 2011 program year.

Integration Complexity - It is not possible to generalize about the difference in relative ease or costs of integration between distributed and central plant photovoltaics. Each project needs to be individually analyzed to determine the impacts on the surrounding grid. The complexity and costs of integration for a central plant project may be greater than those of an individual distributed project, but the sheer volume of distributed projects amplifies the impacts on the Company.

Oregon Solar Program - The Oregon Solar Incentive Program has provided numerous lessons. First and foremost is that incentive levels must be conservatively set. In the authorizing legislation, the program was designed to have a maximum rate impact of 0.25 percent. Current projections estimate that the program will raise rates for customers 0.44 percent for the next 15 years once the program is fully enrolled. This rate impact will be purchasing the power from 9.8 MW of solar installations. The cost has led to some challenges for both the OPUC, which developed the rules, and the solar industry in general.

The second lesson is that an incentive can create a boom and bust cycle for the utility and the solar industry. In order to properly administer the added volume from the incentive, the utility is forced to increase employees to meet deadlines for processing and reviewing incentive and interconnection applications. This can lead to high administrative costs for the programs in addition to the costs of the incentives themselves. The solar industry can also be negatively impacted if it develops a reliance on incentives to close sales. Limited incentive capacity prevents the solar industry from being able to guarantee an interested customer a spot in the incentive. Therefore, sales contracts become dependent on acceptance into the program, which has negative impacts on the solar vendor as it is unable to plan further out than the next enrollment window for the incentive.

Subsidy per kWh - The Oregon Solar Incentive Program is a performance based incentive where the customer is paid per kWh produced by the facility. In order to compensate for the widely divergent solar irradiance in the different bioregions in Oregon, the OPUC created a tiered structure for the incentive. The incentive level a participant receives is based on the county where the system is located. The table below shows the history of the incentive levels and the projected incentive for the next enrollment period.

History of Incentive Levels
Small Systems, 10 kW and under

Rate Zone	July 2010 actual (cents/kWh)	October 2010 actual (cents/kWh)	April 2011 actual (cents/kWh)	October 2011 proposed (cents/kWh)
1	65 cents	58.5 cents	46.8 cents	42.1 cents
2	60 cents	54 cents	43.2 cents	38.9 cents
3	60 cents	54 cents	43.2 cents	38.9 cents
4	55 cents	49.5 cents	39.6 cents	35.6 cents

History of Incentive Levels
Medium Systems, greater than 10 kW, less than 100 kW

Rate Zone	July 2010 actual (cents/kWh)	October 2010 actual (cents/kWh)	April 2011 actual (cents/kWh)	October 2011 proposed (cents/kWh)
1	55 cents	49.5 cents	39.6 cents	35.6 cents
2	55 cents	49.5 cents	39.6 cents	35.6 cents
3	55 cents	49.5 cents	39.6 cents	35.6 cents
4	55 cents	49.5 cents	39.6 cents	35.6 cents

Distributed Wind

5. **Is the integration of the variable output of wind power production made easier or less expensive if it is distributed throughout the service area rather than centralized from a utility-scale wind farm?**
6. **What is the estimated contribution of distributed wind generation to meeting a utility's peak demand?**
7. **Does current distribution capacity constrain development of distributed wind generation?**

Response: Integration of variable output from wind resources becomes less expensive when those resources are diversified such that sudden changes in production from one location can offset changes in production at another location. In this way, the overall variability can be dampened, which can lower the amount of operating reserves that are required to integrate wind resources on a portfolio basis. The benefits that might be achieved from diversification are highly dependent upon the differences in the wind regime among the resources being considered, and thus the more expansive the geographic scope, the higher the prospects of being able to take advantage of diversification. For instance, the Eastern Wind Integration and Transmission Study published by the National Renewable Energy Laboratory (NREL) found that spreading wind out across the Eastern Interconnect helped reduce system variability and uncertainty. The study can be found at the following link:

http://www.nrel.gov/wind/systemsintegration/ewits.html

PacifiCorp studied the peak load carrying capability of wind resources in its 2008 IRP. The study showed that the peak load carrying capability is dependent upon the wind regime in any given region. The peak load carrying capability for wind resources in Yakima Washington were calculated to be 4.7 MW per 100 MW of wind. For Wyoming resources, the peak load carrying capability was estimated to be 5.2 MW per 100 MW of wind. The study further shows that higher wind penetration levels in a given region tends to lower the peak load carrying capability due to high correlation among projects (lack of diversity).

PacifiCorp has not studied whether the current distribution capacity and facilities can accommodate distributed wind generation.

Distributed Hydroelectric

8. **What is the state of the technology for generating electricity from wave, tidal, and micro-hydro technologies (maturation, market penetration, retail price of installation)?**
9. **Do these technologies pose potential negative environmental impacts?**
10. **Are there potential impacts from current environmental regulations for hydroelectric generation that might adversely affect the development of future distributed hydroelectric generation (in other words, should micro-hydro be treated the same as utility-scale hydroelectric generation? Are there other impacts specific to micro-hydro that ought to be considered)?**

Response: In the latter part of 2010 through March 2011, the Oregon Wave Energy Trust (OWET) held a series of workshops with utility stakeholders in southern Oregon, the coast, and the Portland metro area. The workshops were developed by OWET to educate as many Oregon utility stakeholders as possible on the opportunities and challenges facing the wave energy industry. The materials from the workshops are available at the following website link:

http://www.oregonwave.org/our-work-overview/market-development/utility-market-initiative/

Biogas

11. **What is the generation capacity and energy production potential from biogas fuels located in Washington State?**
12. **How are fuel mixtures accounted for, and are there fuel mixes with fuel components that do not qualify under the state renewable portfolio standard (RCW 19.285)?**
13. **What is the range of project capacity sizes for biogas generation resources and how does that compare to the capacity sizes for projects that qualify for published PURPA rates?**
14. **What is the status of municipal green stream digester development, including the status of the eligibility of those projects or potential projects under RCW 19.285?**

Response: Biogas technology has grown to be adopted in processes that use anaerobic digestion to produce the fuel gas, such as dairy farms and wastewater treatment plants. A separate category is landfill gas where the gas is produced as part of the landfill decay and collected for use as a fuel. All of these biogas fuels qualify under the state's RPS requirements. The gas can be used on-site to heat water, cleaned and sold as pipeline quality gas, or burned to generate power. Drivers for market development are related to the size of the host farm or waste-water treatment plant to provide sufficient consistent fuel for generation. Typical biogas projects are comprised of multiple small generation units, usually reciprocating engines, each unit ranging from 250 kW to 1,500 kW, and a total project generally in the 2,000 kW range. These project sizes are all within the range covered by standard-offer PURPA rates across the six jurisdictions that PacifiCorp serves. On a system-wide basis, PacifiCorp has nine biogas projects under standard-offer PURPA contracts and a tenth in negotiations totaling 22.0 MW. In Washington, the Company has one 1.2 MW project under contract.

C. FINANCIAL INCENTIVES

1. **If the cost of building a distributed energy resource is not yet competitive, and a subsidy is recommended, what form of subsidy is best?**
2. **What effect would the subsidy have on encouraging the building of the resource versus research and development?**
3. **Should subsidies, incentives or renewable energy credits be paid or created for power generated through distributed resources while market prices are negative?**

Response: Washington policymakers are ultimately responsible for determining if and when subsidies for distributed energy resources are desirable. PacifiCorp has observed a variety of different state and federal incentive programs at work across its six-state service territory. The financial cost, design, duration, and applicability of each incentive is a product of many considerations that range from the perceived diversity of energy resources, current electricity costs, electricity market structure, economic development, and overall economic health of the state. PacifiCorp does not have specific recommendations as to the amount or structure of new subsidies for distributed energy resources. However, new subsidies/incentives are an explicit admission that these energy resources are not cost effective for customers. Therefore, if Washington policymakers determine that other social, economic, and environmental factors beyond the cost of these resources support subsidies, then the most effective and fair approach is a public subsidy approach (such as Washington's community solar tax credit or the federal renewable energy production tax credit) that advance public policy on a utility customer-neutral basis. Subsidies within and among utility customers are less defensible and fraught with unintended consequences, primarily because of the different ownership structures, rates, customer attributes, geography and business models of individual utilities.

PacifiCorp appreciates the opportunity to provide comments and looks forward to participating in the upcoming work session. If you have any questions regarding these comments, please contact me on (503) 813-6043.

Sincerely,

Andrea Kelly

Andrea L. Kelly
Vice President, Regulation

Enclosures

cc: Elizabeth Osborne, Washington Utilities and Transportation Commission

ATTACHMENT A

Attachment A
Existing Distributed Energy Systems
Net Metering
as of July 14, 2011

State (# of Customers in PacifiCorp's Service Territory)	Net metering technologies	Number of net metering systems	Size (kW)
WA (126,665)	**Total**	**32**	**279**
	Solar	30	256
	Wind	2	23
	Hydro	0	0
	Biogas	0	0
	Fuel Cell	0	0
	CHP	0	0
OR (555,070)	**Total**	**1,637**	**9,369**
	Solar	1,612	9,100
	Wind	18	75
	Hydro	4	172
	Fuel Cell	0	0
	Landfill Gas	0	0
	Digester Gas	0	0
	Waste	0	0
	Energy Crops	0	0
	Biomass	0	0
	Wind/Solar	3	22
CA (45,148)	**Total**	**37**	**200**
	Solar	32	183
	Wind	2	3
	Wind/Solar	3	14
UT (787,550)	**Total**	**924**	**3,241**
	Solar	874	2,933
	Wind	36	120
	Fuel Cell	1	15
	Organic Waste	0	0
	Hydro	1	2
	CHP	0	0
	Biomass	1	75
	Woody Debris	0	0
	Agricultural Residue	0	0
	Energy Crops	0	0
	Landfill Gas	0	0
	Biogas	0	0
	Geothermal	0	0
	Wind/Solar	11	96

Attachment A (continued)
Existing Distributed Energy Systems
Net Metering
as of July 14, 2011

State (# of Customers in PacifiCorp's Service Territory)	Net metering Technologies	Number of net metering systems	Size (kW)
ID (70,281)	**Total**	**83**	**381**
	Solar	19	145
	Wind	64	236
	Hydro	0	0
	Biomass	0	0
	Fuel Cell	0	0
WY (133,770)	**Total**	**133**	**567**
	Solar	70	310
	Wind	54	214
	Hydro	0	0
	Biomass	0	0
	Wind/Solar	9	43
Total		**2,846**	**14,037**

ATTACHMENT B

Attachment B
Existing Distributed Energy Resources with a capacity of 20 MW or less connected to PacifiCorp's distribution or transmission system (excludes net metering customers' projects provided in Attachment A) as of July 14, 2011

State	Interconnected Generation Type	Number of Generation Systems	Size (kW)
WA	**Total**	**6**	**25,270**
	Hydro	5	24,070
	Biogas	1	1,200
OR	**Total**	**40**	**179,510**
	Hydro	20	37,050
	Biomass	4	37,530
	Wind	10	74,550
	Biogas	1	1,600
	Geothermal	1	280
	Natural Gas	2	20,500
	Landfill Gas	2	8,000
CA	**Total**	**7**	**19,518**
	Hydro	5	9,510
	Biomass	2	10,008
UT	**Total**	**14**	**50,072**
	Hydro	3	1,940
	Biomass	1	1,600
	Wind	3	19,935
	Natural Gas	1	7,600
	Landfill Gas	1	4,800
	CHP	1	7,540
	Biogas	4	6,657
ID	**Total**	**14**	**22,666**
	Hydro	13	20,970
	Biogas	1	1,696
WY	**Total**	**9**	**37,927**
	Hydro	3	4,737
	Natural Gas	2	1,990
	Solar	1	50
	Wind	2	20,150
	CHP	1	11,000
Total		**90**	**334,963**