Comment Summary
From July 15, 2011
Docket UE-110667
Potential for Distributed Energy in Washington

A. General – Cross-Cutting Issues:

A1. 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?	
Avista	*Distributed Energy Installations in IOU Service Territories* Avista has the following distributed energy customer installations in the state of Washington: • 2 Hydro for 3 MW; • 76 Solar for total generation capacity of 333 kW; • 14 Wind for capacity of 98 kW; and • 6 Wind-Solar for capacity of 18 kW These installations total 3,449 kW of generation capacity. Avista has approximately 30 new installations annually; this number is expected to remain consistent absent new incentives. Solar generator installations are expected to be the majority of distributed energy installations in the future since wind and hydroelectric sites are limited in Eastern Washington.
Puget Sound Energy (PSE)	*Resource Potential* The technical and market potential of these technologies is best answered by private consultants with access to a myriad of data and market knowledge. PSE defines "distributed" by power generation capability as up to 5 MW, which can be interconnected to the distribution grid or substations at 35 kV or less. Important to consider: • interconnection standards and code compliance; • dispatch control; and, • peak demand value
Pacific Power (PacifiCorp)	*Distributed Energy Installations in IOU Service Territories* 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. • 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.

Resource Potential

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.

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)
- 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.

US DOE Northwest Clean Energy Application Center (NW CEAC)

Resource Potential

A wide range of distributed technologies are emerging in this state (steam and natural gas turbines, microturbines, stirling engines, stationary fuel cells, northern climate digesters with up to 9 revenue streams (dairies for example), high solids digesters (food processors and compost facilities), wood biomass CHP systems (forest products and pulp and paper mills), organic rankine cycle/waste heat to power systems (natural gas compressor stations, metal smelting and other industrial facilities with high thermal requirements)

	Combined Heat and Power • The total technical market potential for CHP including all technologies is over 3,000 MW (see attachment three) • Determining the economic potential based on the technical potential would require significant analysis, which has not been done. Industrial prices above 8 cents/kWh are of interest.
Northwest Energy Coalition and Renewable Northwest Project (NWEC)	*Resource Potential* According to the Renewable Energy Atlas of the West, the total technical potential for various renewable resources in Washington are as follows: a. The wind resource in Washington can produce an estimated 7,000+ aMW of energy, which is equivalent to approximately 22,000 MW of nameplate capacity. Currently there are around 3,000 MW of nameplate wind capacity installed or under construction in Washington. The best wind resources are concentrated in South-central, Southeastern, and the Western coastal region of Washington (see Appendix A) b. The potential for solar photovoltaic (PV) generation in Washington is estimated to be 4,700 aMW. Assuming a 15% capacity factor, this represents approximately 31,000 MW of nameplate PV capacity. Although solar PV can be a viable option anywhere in the state, the best solar resource is concentrated east of the Cascade Mountains (see Appendix B) c. The potential for electric generation from biomass is roughly 1,250 aMW. This includes agricultural and woody biomass sources. At a 50% capacity factor, this would represent 2,500 MW of nameplate capacity, while at an 80% capacity factor this would be roughly 1,560 MW of nameplate capacity. Biomass resources are distributed throughout the state, with a heavier concentration on the West side
Local Energy Alliance of Washington (WALEA)	*Resource Potential* WSU has documented the number and size of installations receiving the state's cost recovery program by utility, but we aren't aware of a comprehensive record of all projects meeting the state's current definition of distributed generation, up to 5 MW. • *Solar* – Distributed Solar Power has a virtually unlimited theoretical potential, but if it is reasonably limited to rooftops parking lots, and other land and surfaces which would not otherwise be productively using the sun (i.e. not over agricultural, forest, or wildlife lands) the potential is 100s of MW. • *Wind* – Distributed wind power has the technical potential for thousands of MW of installed capacity across the state in installations 5 MW and under. • *Hydrokinetic* – Distributed hydrokinetic energy from run of stream projects, irrigation channel, hydro, and dam improvement projects, has a potential of 100s of MW across the state. Ocean energy is still a developing field and the viability of projects under 5 MW is still a question mark; 100s of MW of distributed ocean energy may be reasonable. • *Biomass* – Distributed Biomass projects, especially district heat and

	industrial heat based co-generation facilities have the potential of 100s of MW across the state. • *Biogas* – Biogas, including dairy, and municipal solid waste have a potential of 100s of MW across the state. Wastewater treatment facility biogas has potential to generate over 4,000 MW of electric power within IOU service territory in Washington state • *CHP/District Energy* – a 2004 study funded by the U.S. Department of Energy showed a potential offset of 123 MW if a district energy system is built in the "Denny Triangle" area of downtown Seattle (not in an IOU but still a good benchmark). Similar studies funded by US DOE show more than 4,000 MW of technical potential across Washington State.
King County Department of Natural Resources and Parks (DNRP)	DRNP has the following facilities which might be impacted by this study: • Cedar Hills Solid Waste Landfill • South Treatment Plant in Renton • Sewage to Energy Demonstration Projects (multiple locations) *Landfill gas* Landfill gas is a significant distributed energy resource in Washington State, and King County operates a large landfill at its Cedar Hills site. At Cedar Hills, the King County SWD sells LFG, a qualified renewable energy supply, to BioEnergy Washington (BEW). BEW refines and compresses the gas to pipeline quality gas and sells it to PSE. Refining of LFG for sale as pipeline gas is not likely to be widely employed in the state due to limitations on access to large-volume gas transmission pipelines, where such injection may be allowed. Pricing of gas that is qualified as a renewable energy supply such as this, is currently on contract basis. *Biogas* South Treatment Plant in Renton currently scrubs and sells digester gas derived from the wastewater treatment process to PSE. King County's Wastewater Treatment Division (WTD) is currently studying the potential to increase digester gas production by locating a brown grease disposal facility at the treatment plant. This study is expected to be complete in 2011 and the increase in digester gas production will be estimated at that time. King County WTD is working with several local real estate developers on Sewage to Energy Demonstration Projects where heat energy transfer technology may be used at a neighborhood or building level. For each district energy project, a real estate developer or private company would develop the neighborhood utility and identify an operator to manage and operate the distributed energy facilities. King County WTD would provide a fuel source via sewage in urban conveyance lines and have no operations or maintenance liability.
Cascade Power Group	Rather than focusing on transitioning from one centralized fuel source to another, we believe Washington State should focus on conservation of existing energy through system improvements to the energy delivery system itself.

(CPG)	Conservation has been identified by federal authorities and industry stakeholders as a key resource in the coming decades. Combined Heat and Power (CHP), Waste Heat Recovery and District Energy Systems are proven technologies that capture the waste energy that we already pay to produce. *Resource Potential – Combined Heat and Power* The on-site technical potential of CHP in Washington State is calculated as being well over 4,000 MW by WSU Energy Program's "Northwest Clean Energy Application Center" in a 2010 study. Most of this potential is found in the petroleum refining, food processing, primary metals, wood products and paper products industries. This also includes 235 MW of waste heat potential. Another study funded by the U.S. Department of Energy in 2004 found a potential offset of 123 MW if a district energy system is built in the "Denny Triangle" area of downtown Seattle. That is a huge energy savings for such a small area. These examples are all MWs that exist now and with the correct application of policy incentives we can capture them.

A2. What is, or what is anticipated to be, the overall cost of integrating distributed energy resources to investor-owned utilities?	
Avista	Costs for larger projects, generally over 100 kW, vary greatly and are dependent on the specific circumstances. The generator is responsible for the interconnection costs. The costs of integrating small distributed energy resources through net metering are mainly associated with Company personnel time and travel resources. Avista inspects, verifies protection, and commissions each installation. The anticipated cost of integrating these small distributed energy projects is approximately $30,000 annually, based on 30 new installations a year. Where the number of installations increases, so will the annual cost. In terms of the hour-to-hour and minute-to-minute operation of Avista's electric system, the amount of distributed energy resources are small at this time and generally do not have an impact on load/resource operations.
PSE	Integration costs fall into two general categories: interconnection costs; and system integration costs. Interconnection costs are primarily a function of the size of the resource, the existing load on the line the distributed generation resource will feed into, and the safety equipment that is integrated into the resource. Integration of residential solar is not material since the equipment includes a UL 1741 listed inverter. UL 1741 standards are based on IEEE 1547 which was developed over many years to allow distributed solar systems to put electricity back on a circuit that was designed for power flow in only one direction. The key elements of a UL 1741 inverter are to ensure power quality and safety by preventing power flow when the circuit is not energized. If the distributed generation resource is not UL 1741 compliant, or if the resource is larger than 300 KW, then interconnection requires a series of studies to determine system impact, and to identify necessary measures (WAC 480-108). The studies and the additional equipment can be costly. For a project of 500 KW to 5 MW, PSE estimates that the studies will cost in the range of $25,000

	in 2011. Additional costs come from necessary equipment such as transformers, meters, larger conductors, etc. The cost and cost avoidance effects, if any, of DG, will be dependent upon the types of interconnected technology, their system locations, intermittency characteristics, and overall degree of penetration. PSE's experience with distributed generation interconnections has increased dramatically over the last two years with technologies that include small wind, micro-hydro, dairy digesters, waste-water methane collection and community solar. In addition to interconnection costs, there are system-integration costs associated with incorporating intermittent resources into the grid. Most of our analysis of these kinds of integration costs has focused on wind resources, but we would expect the magnitude to be similar.
PacifiCorp	PacifiCorp has not developed an estimate of the overall cost of integrating distributed energy resources.
NW CEAC	*Combined Heat and Power* CHP is baseload, not intermittent power. It is located next to end user loads and thermal needs. This takes pressure off the transmission and distribution lines (a societal benefit). This is especially true in Western WA. While the costs of interconnection need to be recognized, the broader societal benefits such as transmission and distribution improvements should also be recognized in a balanced way.
WALEA	Currently the owners of distributed energy facilities pay the integration costs so the cost to IOUs is zero. At higher penetration rates (say 10-30 % of a local grid's capacity) some system wide improvements, such as smart grid technologies, may become necessary and will need to be borne by the utility.
CPG	Under the existing interconnection rule, customers pay all costs for interconnecting distributed energy resources to a utility company's infrastructure. Because the cost data from individual customers is not widely captured or documented, the true costs borne by customers is uncertain. We know from recent experience that a 355kW solar array being interconnected to PSE's distribution system in Kirkland, WA will cost approximately $5,000 and is mostly due to overcurrent protection and relays required by the state interconnection rule.

A3. Describe the incentives paid by or through investor owned utilities. How much is paid annually for each technology?	
Avista	Avista provides state incentive payments under WAC 458-20-273 which authorizes a customer investment cost recovery incentive payment to help offset the costs associated with the purchase and use of renewable energy systems located in Washington State that produce electricity.
PSE	Currently, for distributed generation projects, PSE pays for the electricity produced and the Renewable Energy Credits when contracted for. PSE provides for net metering, when applicable, under state law. The costs of net

<table>
<tr><td></td><td>metering are paid for by all customers through their general rates. PSE makes the payment of the state incentive production under WAC 458-20-273. PSE makes these payments directly to qualifying net-metered customers and recoups the cost through state tax reductions.</td></tr>
<tr><td>PacifiCorp</td><td>PacifiCorp currently offers incentive programs in four of the six states in which it operates. [See Comments of Pacific Power at p. 3-5 for descriptions of incentive programs in other states]
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.
<table>
<tr><th colspan="3">Washington Renewable Energy System Cost Recovery Incentive Cost</th></tr>
<tr><th>Year</th><th>Number of Participants</th><th>Incentive Amount ($)</th></tr>
<tr><td>2009</td><td>3</td><td>$1231.35</td></tr>
<tr><td>2010</td><td>12</td><td>$9342.56</td></tr>
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<tr><td>NWEC</td><td>It should not be assumed outright that the costs associated with integrating DG would result in increased revenue requirements for utilities. For example, in New York State, it is estimated that the total value to ratepayers of integrating distributed solar PV generating capacity ranges from $0.09-$0.25/kWh, while the costs associated with integration range from $0.00- $0.05/kWh. When the economic, environmental, and social benefits of distributed PV are included, the combined value to ratepayers and taxpayers increases to between $0.15/kWh (assuming a $0.05/kWh penetration cost) and $0.41/kWh (assuming no penetration cost).
Any attempt to estimate the cost to IOUs of integrating DG would ideally be accomplished through a rigorous study that assesses the impact of DG in terms of not only its nameplate cost against the value of the electricity it is offsetting, but also in terms of the indirect benefits it brings to the grid such as capacity contributions, reduced electrical losses, fuel price mitigation, and grid security enhancement. [See Comments of NWEC and RNP, Table 1: Value Analysis of Distributed Solar PV Grid Integration, p. 2]</td></tr>
<tr><td>WALEA</td><td>WA Renewable Energy Production Incentives: $0.12-$1.08/kWh through 2020 depending on project type, technology type and where equipment was manufactured. Paid for by utility, but recouped in tax rebates. $5,000/year maximum incentive per recipient. The total of each utility's payments are capped at 0.5% of their previous year taxable revenue. For example, Puget Sound Energy, with revenue of $2.3 billion, can pay out approximately $11.5 million per year. They do not anticipate customer generators to tap all this incentive until at least 2015. The base rate of $0.15/kWh is multiplied by the</td></tr>
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	following factors [see RCW 82.16.120]. This and net metering are the most significant statewide incentives. Most other incentives offered mostly by PUDs and through BPA programs are low-interest loans (about 4.9-5.8%) to help finance the capital costs of RE investment.
DNRP	*Biogas* PSE currently pays King County WTD $0.56/therm (indexed to residential rate) for scrubbed digester gas.
CPG	• Current WA Renewable Energy Production Incentives: $0.12-$1.08 through 2020 depending on project type, technology type and where equipment was manufactured. Paid for by utility, but recouped in tax rebates. $5,000/year maximum incentive. [See RCW 82.16.120] The 'in-state manufacturing incentive' and Net Metering are the most significant statewide incentives. Most other incentives offered mostly by PUDs and through BPA programs are low-interest loans (about 4.9-5.8%) to help finance the capital costs of RE investment. • There is no public benefits fund, nor is there an equipment buy-down program for emerging technologies. • Clean Energy Standard Offer Program (CESOP) policy: Distribution utilities offer qualifying clean-energy plants long-term contracts for power at 85% of the delivered cost from the best electric-only power plant. Qualifying clean-energy plants must be at least 60-percent annual fossil efficient or be non-carbon-emitting power plants such as renewables or nuclear. Distribution utilities keep retail customers, fund interconnection facilities to qualified clean-energy plants, and earn returns on up-front investment. Qualified CESOP plants will not be considered a major modification to industrial processes under the Clean Air Act, thus removing threat of operating permit loss.

A4. 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, **o Would current interconnection standards need to be changed to accommodate more distributed energy or to accommodate different distributed energy technologies? Why?**	
Interstate Renewable Energy Council (IREC)	*Third-party ownership* Regulatory change to allow 3rd-party owners of DG to operate in WA: • The Commission can act on its own to clarify that a 3rd-party owner is not an electrical company subject to UTC oversight (through a declaratory order or a rulemaking); or, • Legislature could exempt 3rd-party owners from electrical company status and UTC oversight

	Benefits of allowing 3rd-party DG ownership:
	• 3rd-party owners can take advantage of 30% federal tax credit and accelerated depreciation
	• Non-profit facilities, schools, and government facilities do not pay federal taxes, but 3rd-party owners that can use these benefits may pass through lower costs to these customers
	Net-Metering
	• Increase the eligible system cap through legislation to at least 2 MW, or eliminate size restrictions for systems designed not to exceed on-site load
	• Increase program participation limits – WA's current net-metering cap of 0.25% of utility peak demand should be increased beyond the 0.5% cap scheduled to begin in 2014 to 5% of utility peak demand or greater of current levels (not 1996 levels)
	• Maintain Commission and local regulatory discretion to set the program cap higher – UTC should raise the cap for IOUs
	Changes to current interconnection standards
	• Legislature could provide statewide uniformity for the interconnection process for IOUs, COUs, co-ops, and municipalities.
	• UTC could lower costs of interconnection by:
	  o 1)prohibiting requirements for external disconnect switches for inverter-based systems, which IREC states are redundant, unnecessary, and add significantly to overall project costs;
	    ▪ UTC could issue a rulemaking to remove the external disconnect switch requirement
	    ▪ UTC could encourage legislation to remove the requirement, and
	  o 2) prohibiting requirements for additional insurance to cover liability
	  o 3) adopting FERC "Fast Track" technical screens for generators of 2 MW or less
	    ▪ Or, modify the screen that limits aggregated generation on a distribution circuit to 15% of the line section annual peak load; instead base screen on 50% of minimum load (during the hours of 10 am and 3 pm being explored by California utilities)
	    ▪ Require utilities to make the available capacity of distribution facilities at the circuit level publicly available to help generators identify suitable points of interconnection

Avista	[For examples of existing financial incentives for renewable DG, see Comments of Avista, p. 5] *Financial Incentives* • Financial incentives in the form of utility-based subsidies may be costly enough when they are designed to lower the cost of distributed generation to match a utility's avoided cost of acquiring a generation resource

	• Even more significant cost-shifts would occur from utility-based subsidies that are intended to reduce the cost of distributed generation to the level of a utility's cost of service. • 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/generator will not only recover all of its investment in a resource that may not otherwise be cost-effective, but also a profit. *Interconnection* • Changing current interconnection standards to accommodate (presumably) larger generation resources risks intruding on the jurisdiction of the Federal Energy Regulatory Commission (FERC), in the event those interconnection standards affect facilities involved the transmission of electricity in interstate commerce. They might also mean that greater costs could be borne by other utility customers. • As a general rule, use of interconnection standards as a method of subsidizing distributed generation should be avoided.
PSE	Financial incentives need to be targeted at specific technologies. In general, if they are technology neutral, the investment dollars tend to flow almost exclusively to where the returns are most lucrative. In general the interconnection standards were written for safety and reliability. One possible change is to investigate whether the WAC 296-45-335 requirement for a visible disconnect switch could be removed for systems that are UL 1741 protected.
PacifiCorp	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.
Cascade Community Wind Company (CCWC)	*5 MW Limit on Distributed Generation* The state's current definition limiting distributed generation to 5 MW is reasonable, though a higher limit could be used. It is essential, however, that non distributed projects are prevented from calling themselves distributed by stretching or bending a definition. Both Oregon and Idaho have recently been bitten by commercial wind farms splitting themselves up into multiple 10 MW pieces to qualify for distributed generation incentives. We have seen policy in other states which gives regulators discretion to disqualify projects that are obviously gaming the system. *Avoided Cost Rate for Distributed Renewables* Puget Sound Energy, through their Schedule 91 avoided cost rate, provided a market for our power at a fair price. Other utilities in Washington do not currently offer an avoided cost rate for distributed renewables. *Financial Incentives* Federal Incentives were changed with the Recovery Act to be a simple

	refundable Investment tax credit anyone could take, a change from the production tax credit which could only be taken against passive corporate income. Simply making incentives apply to regular people was critical for allowing regular people to develop renewable energy. The Washington Production incentive currently has little or no impact on community wind projects at this point. We look forward to the incentive being changed from a $5k cap per project to the same $5k cap per participant incentive that community solar projects enjoy. This is preferable to simply raising the cap. *Permitting* Kittitas County provided a process to install our two 100 kW wind turbines, yet they have no process for a farmer to install a turbine any larger. Other counties we work in have similar difficulty understanding and providing a permitting path for distributed wind. This issue is critical to the distributed wind energy industry.
NW CEAC	*Changes to RCW 19.285* • Definitions of "bioenergy" in RCW 19.285.030(18) exclude high solids digesters (food processors and compost facilities) block at least 20 MW to technical market potential. Food waste and green waste should be added to the list of renewable energy. • RCW 19.285.030(13) regarding "nonpower attributes" should be limited to electrical generation. The shutdown of dairy manure lagoons is a methane reduction pathway for sale of greenhouse gases. • Spent liquor should be added to the list of renewable energy. See RCW 19.285.030(18). *Net Metering* • Limit should be increased to 2 MW similar to Oregon OPUC action.
eFormative Options	*Wind Resources* • Washington has a lower incentive level than California, Oregon, and other states; WA is missing out on reaping substantial economic benefit • Upfront payments are important in aiding consumer financing. A supplement to the state's existing performance-based incentive (PBI) could create a hybrid approach to issue partial payments upon construction based on estimated production using certified power curves and wind map calculations. Such a program can be expensive to administer, which could reduce the amount of funds available for incentives. • Scaling incentives based on AWEA Rated Power, wind map ratings and tower height could be a simpler approach to encourage proper siting. Reducing incentives gradually over time can also aide the market in reducing costs for consumers. • Requiring that small wind turbines are certified by an independent certification organization such as the Small Wind Certification Council (SWCC) in order to qualify for incentives is extremely important for several reasons. o It maintains the integrity of the industry

	- Provides the state with some certainty of turbine performance, so rate refunding is used prudently. Prompt deadlines need to be set for requiring certification to ensure manufacturers prioritize and complete testing in a timely manner. - Through the end of 2011, incentives should be limited to turbine models with power performance tests conforming to AWEA 9.1 – 2009 that have been verified by the SWCC.
NWEC	- Varying costs and scale of the DG technologies in question must be considered. Also, the meaning of "neutral" policy must be specifically defined. If the attempt is to encourage the least-cost technologies, then a single incentive level is appropriate. On its face, this incentive would be "neutral" by not identifying a single technology that it encourages, but in reality this incentive would promote only the technology or technologies that are made economically viable by the given incentive level. If the attempt is to encourage similar amounts of development of multiple technologies, then the incentive program must be structured based on technology and size-specific costs. Due to the multiple benefits associated with energy resource diversity, including complimentary resource profiles and increased grid stability and security, a DG incentive that encourages the development of multiple renewable technologies is preferable to one that encourages a single technology. - The incentive level is more important in determining the extent of an incentive program's neutrality, while the mechanism by which the incentive is delivered is less deterministic (e.g. cost-based incentive or production-based incentive). For example, distributed wind, solar, and biomass can and do function in incentive programs based on production (e.g. Federal Production Tax Credit, Washington Renewable Energy System Cost Recovery Program, or Oregon Solar Feed-in Tariff), cost (e.g. Federal Investment Tax Credit (ITC), Federal ITC Grant, or Oregon Residential/Business Energy Tax Credit), or a combination of both. - Although both production and cost-based incentives have been effective in encouraging renewable energy development in the US, the feed-in tariff (FIT) mechanism (i.e. production based incentive) has proven to be highly effective in incenting distributed solar PV across the globe. However, a FIT program does not need to focus on solar PV alone. 3rd-party ownership of DG systems should be incorporated into any DG incentive program
WALEA	Yes, regulatory changes are needed to facilitate the deployment of distributed energy projects. Current *interconnection standards* should 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 the utility's system. All such systems would obviously have additional standardized protective relays and disconnect switches, but otherwise the

	process should be no more difficult. • *Avoided Cost Payments*: California, Oregon, and many other states have avoided cost rules that specify that distributed renewable energy projects need to be paid the cost of the most expensive source of energy being used by the utility at any time. Puget Sound Energy has voluntarily created such a rate for distributed projects, Schedule 91. These costs are estimated and projected out into time such that a standard set of prices can be set for a project at interconnection that ensures the project its pricing during the project's financing. These avoided cost payments are and should be structured to be cost neutral to the utilities. This sort of stable fair rate for power is the base that distributed energy projects of all technologies should be able to rely on. • *Community Net Metering*: allow neighbors to share in a single distributed renewable energy system. Similar to avoided cost pricing, Community Net Metering gives distributed generation projects access to the market at no cost to the utility or to the taxpayer. WALEA recommends a policy that follows the IREC guidelines quite closely. The 2011 bill HB 1049 in most respects does this. Policy built upon this bill would be a great boon to distributed generation in that it would allow customers to choose to participate in local renewable energy projects, avoiding many NIMBY issues as all the beneficiaries of a project would be local. • A *Feed in Tariff* (FIT) is the world's most effective mechanism for encouraging distributed generation. Fair market access combined with a well thought out cost recovery incentive could have the same effect of a feed in tariff. Non-Utility Policies: • *Permitting* – SHB 1081 which passed both the House and the Senate in 2011 but could not be reconciled between the two houses was an attempt to correct the woeful lack of siting rules in most counties and cities for distributed generation. Ensuring that appropriate distributed energy projects have a permitting path in all jurisdictions (where appropriate) is a key element to enabling growth of the sector. • *Air Quality* – Combustion based distributed generation such as anaerobic digestion, biomass cogeneration, and even natural gas based district heating deserve lighter regulation by air quality laws than they currently receive. These technologies often reduce emissions (digestion removes a methane and odor source) or replace multiple other sources (district heating replaces multiple unregulated heat sources). State of the art installations should not have a significant air quality compliance burden while there still should be protections against technologies of this scale that don't meet industry standards.
Snohomish Public Utility	*Financial Incentives* *Local Authority* Establishing financial subsidies at the state level for DG takes away from the

District No. 1 (SnoPUD)	local governance and decision-making authority that has been reserved by our ratepayers. Incentives could result in windfall profits to developers at the expense of ratepayers *Consideration for utility resource need* There is a surplus resource at this time; consideration must be given to utilities that have a large number of DG customers wanting to interconnect, but do not have a resource need. This may result in utilities purchasing energy only to resell it at a loss in the wholesale market, resulting in higher electric rates and risk to utility ratepayers. *Interconnection* • Several components of the interconnection process and the agreement between generators and the utility could be standardized, but the type of resource and its point of interconnection would determine whether interconnection would be standard or unique. For example, a 2 MW generator interconnecting at the end of a feeder in a remote area will likely require additional equipment and interconnection facilities, compared to a 200 kW generator located near a major substation. • It is important that utilities be allowed to maintain flexibility to develop their interconnection processes appropriate to each resource and system configuration *Permitting* Permitting and regulation are barriers for wave, tidal, and micro-hydro technologies. • Recommend that agencies and stakeholders first approach the deployment of single devices and small arrays so that until proven otherwise, would have small impact projects with minimal environmental effects • Support adaptive management as a solution to confirm initial assessments of low-impact, and monitoring for long-term impacts that are undiscovered
DNRP	*Changes to RCW 19.285* • King County's scrubbed gas system at South Treatment Plant was built in 1987 and does not qualify for Renewable Energy Credits (RECs). It is one of only a handful of wastewater gas scrubbing systems in the nation. Qualifying for RECs would improve the economic viability of current or expanded production levels. • Energy captured from sewage in conveyance lines, before it reaches a treatment plant, should also clearly be defined as "renewable" in State legislation. As noted below, 1-937 has left some question as to whether sewage-based energy (through heat recovery or other technologies) will qualify as "renewable" in Washington State.
Farm Power Northwest,	*Long-term fixed-price standard contracts* In order to encourage technology-neutral development of distributed energy, state statutes should require investor-owned utilities to offer long-term fixed-

LLC (FPNW)	price standard contracts at just below projected retail electricity rates to distributed generation projects. Long term means at least fifteen years, rather than the five years currently required. Fixed-price means a forward strip of at least fifteen years, and the price of just below retail is a reinterpretation of "avoided cost" that is far more meaningful than the cost of running a distant utility-scale power plant. A realistic calculation of the avoided cost of electricity delivered to a local feeder by a distributed generation project should be based on the value of that electricity delivered to the next customer on the feeder, minus nominal administrative and balancing costs.
CPG	*Clean Energy Standard Offer Programs and other Feed-in-tariffs* • Utility company rates should sufficiently bridge the gap between the cost of producing renewable energy and improving efficiency of existing system; and the current cost of producing fossil fuel based energy. The rates should be based on system operational improvements and environmental impact rather than defining a specific type of technology. This is the best way to incentivize innovation and improvements. Clean Energy Standard Offer Programs and other Feed-in-tariff incentive payments are based on such, and are an effective way to mitigate CO2 and gain energy improvements locally. *Interconnection Procedures Best Practices:* • Set fees that are proportional to a project's size. • Cover all generators in order to close any state or federal jurisdictional gaps in standards. • Screen applications by degree of complexity and adopt plug-and-play rules for residential-scale systems and expedited procedures for other systems. • Ensure that policies are transparent, uniform, detailed and public. • Prohibit requirements for extraneous devices, such as redundant disconnect switches and relays, and do not require additional insurance. • Apply existing relevant technical standards, such as IEEE 1547 and UL 1741. • Process applications quickly; a determination should occur within a few days. • Reduce costs of system impact study • Standardize and simplify forms. *Interconnection Recommendations for WA*: • Prohibit requirements for redundant external disconnect switch • Prohibit requirements for additional insurance

A5. What storage options exist that could be used to help integrate distributed energy into the electric grid?	
IREC	Energy storage may face some of the same regulatory problems as generation when storage devices export power under a sale contract; recommend that the Commission and Legislature remove regulatory barriers/uncertainty.

	Commission should direct utilities to credit production from generator prior to storage (IREC's understanding is that the state production tax credit is based on net production after losses in storage)
Avista	There are several existing technically available storage options to help integrate distributed energy in the electric grid: pumped hydro storage, various types of battery technologies, compressed air storage, flywheels, and customer based storage. With the exception of pumped storage, storage options have not developed to the scale where it can be constructed and operated in an economic manner. Pumped hydro is commercially available but may not be economically viable in the current market conditions.
PSE	On the residential scale, batteries could be used to help integrate variable distributed energy. On a larger scale, several companies are endeavoring to commercialize larger-scale energy storage options, with capacities ranging from 0.5 to 2.0 MW with 0.25 to 6 hours of discharge capability. Such units are as large as tractor-trailers and could conceivably be deployed at commercial and industrial facilities, at substations, or other strategic locations as space and interconnection feasibility allows. PSE investigated several technologies in detail, including sodium-sulfur (NaS), zinc-bromide (ZBr) flow batteries, advanced lead-acid, and flywheels in detail and concluded that even considering the multiple benefits of T&D upgrade deferral, renewables integration, system reliability, and energy arbitrage, the currently available technologies are not cost-effective at this time.
PacifiCorp	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.
WALEA	Storage only becomes necessary when generation levels exceed local minimum load and export capabilities which would come at very high penetration levels. Up to about 10% penetration levels of distributed energy can be seen as a 'negative load' and treated no differently than the normal variation in loads. Currently in almost all localities distributed energy is well under 1% penetration. Integrating capacity up to 100% of a local substation's minimum load is possible without storage. The spatial, technology, and scale diversity of distributed energy allows for greater aggregate capacity interconnected without storage or other system improvements than for a single resource at a single location. • A district energy system is capable of thermal energy storage and can help to manage peak electric-loads by shedding excess generation into the thermal energy loop, or by extracting excess thermal energy and converting to electricity. • Grid-aware battery banks are coming on to the market at scales from the

	individual home up through multi-megawatt installations to support firming of large wind generation plants. • Pumped hydro is likely the most accessible storage technology currently. This technology can be implemented regionally at existing dams especially projects like upper and lower Baker river projects where two reservoirs are involved. On a distributed scale many municipal water systems have significant drop across their system and either existing excess high elevation storage or the capability of adding this storage. This distributed pumped hydro storage if properly valued could give our municipal water utilities additional revenue from their existing infrastructure. • Smart grid technology using dispatchable loads, including plug in vehicles, is maturing to simulate a form of storage.
CPG	A district energy system is capable of thermal energy storage and can help to manage peak electric-loads by shedding excess generation into the thermal energy loop, or by extracting excess thermal energy and converting to electricity during peak hours (or hours of low supply). For electric-only storage, battery technology is improving rapidly and early results at pilot projects [for a list of example pilot battery technology projects, see Comments of Cascade Power Group, p. 5].

A6. 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?	
Avista	For Avista Utilities in the State of Washington, distributed energy technology deployment has been limited. The Company currently offers avoided costs rates under Schedule 62, "Small Power Production and Cogeneration" Schedule. The Company does not have any end-use customers selling energy to Avista under that Schedule. The Company also has Schedule 63, "Net Metering," which is applicable to customers with an electrical generating capacity of not more than 100 kilowatts. The Company currently has 96 customers on Schedule 63, providing 449 kW of generating capacity. The level of participation by Avista's customers in distributed energy technologies has not reached any sort of a critical mass, and therefore has not caused a noticeable impact on current rates. As to the future of distributed energy technologies impact on rates, please see the Company's response to question A4 above.
PSE	Customer-owned distributed generation creates loss of load and under recovery of fixed costs in much the same way as energy efficiency. At present, this effect is not material to PSE's financial results, but could become so as distributed generation penetration rates increase without compensatory regulation. A regulatory mechanism could be designed to mitigate the negative loss of load and revenue effects that distributed generation has on a utilities' ability to recover its fixed costs of rendering service. As distributed generation

	penetration rates increase, the issue of system cost shifting to the remaining customers may grow. However, the distribution system we enjoy today was constructed upon the rate model of socialized or rolled-in-rates. It is not clear that the evolution of distributed generation applications yet merits any deviation from such historic rate making practices at this time.
PacifiCorp	• 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 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.
WALEA	Currently ratepayers are not or are only very marginally impacted by distributed generation, additional ratepayer absorbed costs are fairly small and the scale of implementation of distributed generation is small enough that ratepayer benefits such as avoided transmission upgrades have not been substantially realized. In crafting a distributed generation future, both costs and benefits should be accounted for accurately, including costs currently externalized by industry such as the public health costs of respiratory illness and mercury pollution from fossil energy generation.
FPNW	No; most utilities offer well below retail rates for electricity from distributed generation projects, and the projects absorb their own interconnection costs. Future rates would not be impacted if utilities raised their payments to distributed generation much closer to—but not above--retail rates.

CPG	• Existing BPA 'slice' customers and large industrial end-users have lower rates than other customer classes and, therefore, will be impacted by higher rates more significantly than others. • Fossil fuel subsidies have clouded the cost models for renewable generation, not providing a true 'apples to apples' comparison for resources. As market prices for oil and natural gas continue to rise, electricity prices will follow - and as they do renewable energy technologies for distributed power production will become cost-competitive (i.e., grid-parity). Utility companies will "follow" low cost fuels in order to keep rates low, whereas they should follow efficient systems - that deliver any fuel efficiently (regardless of renewable or fossil-fuel). Vast transmission networks that bring wind power from rural areas to urban ones are using an inefficient energy delivery system. • Important to also note that through efficient systems, we are able to maximize our fuel usage. Using diesel-based delivery trucks to build a 50MW wind farm in rural Eastern Washington and then losing 15% of the production through line loss is a waste of natural resources. Efficient use of renewable natural resources will keep costs low for everyone.

A7. Do distributed energy technologies meet winter peaking needs for investor-owned utilities? Can distributed energy technologies serve baseload 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?	
Avista	Distributed energy technologies may be able to meet some winter peaking needs and provide base load capacity for investor-owned utilities. Resources such as digesters, landfill gas, and co-generation might meet peak load requirements. Other resources such as solar, wind, wave, and hydrokinetics may not be counted on to meet peak needs, although they may still help meet peak load when generation actually occurs. The amount of peaking, or base load contribution will be entirely based on the number, size, technology and actual operation of the resources that are developed.
PSE	Distributed resources that can be installed and dispatched to support the distribution system during peak times may offer greater value and operating flexibility than those that put power on the grid at will, even in times of energy surplus. Common renewable distributed generation resources such as wind, hydro and solar are all intermittent and hence provide minimal value for capacity or peak needs. Solid fuel resources such as biomass and biogas resources are typically operated as base-load, around the clock, and accordingly, have some known capacity and peak value. Non-renewable distributed generation, such as diesel generator sets, have the advantage of dispatch control, and can be made available when needed.
PacifiCorp	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.
CCWC	*Distributed Wind* Washington is blessed with a wind resource that basically follows our loads. On the east side of the Cascades, where summer water pumping is a major load, the wind resource correlates well with the irrigation season. On the west side, where winter heating loads are the major load, the wind also comes mainly in the winter months. Orcas Power and Light Cooperative conducted a study in 2003-2005 which showed that a hypothetical wind power facility would decrease their peak line loading. CCWC's own data from Skagit and Whatcom Counties shows a very high capacity factor (~50- 60%) during the months of Dec, Jan, Feb, for well sited wind plants.
NW CEAC	*Combined Heat and Power* The range of CHP technologies provide baseload power including capacity and, as such, support winter peaking needs. Capacity factors exceed 85 to 90 percent.
WALEA	Each technology and resource region has its own particular qualities in this regard: • Peaking: Though the northwest has a winter peak of local demand it has a summer peak of actual generation as NW utilities strive to sell as much power south as possible. It is reasonable to assume that it is of value to the utilities to offset either period where their most expensive generation technologies are being dispatched. While it is understood that the framework of the UTC is in meeting regional demand it falsely creates a single value point for capacity, midwinter evenings, when in truth the utilities highly value generation at other periods. That said the ideal of distributed generation is to meet local load making the question relevant. a. *Distributed Solar* has a diurnal cycle that closely matches the diurnal load cycle with higher loads during the day and lower loads at night. Solar electric peaks just after noon and loads tend to peak in the late afternoon early evening. Seasonally solar peaks in the summer which is counter to our regional peak winter load but it does match the summer water pumping peak load in agricultural areas in the eastern part of the state. b. *Distributed wind* in Washington does not have a strong diurnal cycle. Washington is fortunate to have its wind resources annual cycle match the area of the state where it is. On the west side of the mountains wind

	energy is more abundant in the winter when the major population centers are experiencing peak heating loads. On the east side of the mountains wind is abundant in the summer when water pumping loads are at a maximum. c. *Hydro* (run of stream, and irrigation) has a very flat diurnal cycle and its seasonal cycle is dependent on the source. Similar to wind irrigation canal hydro power matches irrigation pumping loads and on the west side of the mountains run of stream hydro peaks in winter with heating loads. Dam retrofit and improvement hydro projects may have a degree of dispatchability and storage. d. *Biogas and Biomass* cogeneration projects match NW heating loads quite well since they are dispatched in part due to thermal demand. They are also commonly considered a base-load resource, provided that the fuel supply is adequate to keep the plant operating. • Base-Load: The geographical and technological diversity of distributed generation over a service territory or the state make the aggregate output appear to have a significant base-load component. Hydro, biomass, and biogas each have base load meeting capability independently. Wind and solar have some natural load following tendency as described above.
FPNW	*Biogas* Biogas technologies provide baseload capacity, and they can also meet peaking needs if offered electricity prices designed to encourage such a production profile.
CPG	The seasonal variation in demand is partly due to low light levels, but a significant portion is due to heating demands. Historically low electricity costs in the region have also discouraged the construction of thermal efficiency in housing, resulting in high heat losses during winter. • *Combined Heat and Power and waste heat recovery* distributed by district energy systems could significantly reduce the severity of peaking in the winter months when solar resources are less prevalent. • During the summer, *solar* resources peak in their production in late afternoon, when daily peak demand is highest. • *District cooling systems* may be used in conjunction with district heating to reduce the costs of air conditioning during the summer months. • *Distributed solar thermal* systems have the ability to provide clean, low-cost cooling for data centers and buildings in the middle of summer.

A8. 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?	
IREC	In 2010 FERC clarified that earlier precedents denying states' requests to pay

	generators with specific characteristics a higher rate than a utility's avoided cost do not prevent states from setting separate avoided costs for generators that meet a specific state procurement requirement (e.g. RPS requirements); resources acquired to meet an RPS would justify calculation of avoided costs of other renewable resources rather than from all available resources. In the context of WA's RPS, which includes double credit for eligible DG up to 5 MW, avoided costs could be set at up to double the cost of the least-cost renewable alternative (i.e. utility-scale wind). Avoided costs derived from a market mechanism may more accurately represent the price necessary to support renewable DG development.
Avista	Yes. Under section 210 of PURPA, electric utilities are obligated to offer to purchase available electric energy from Qualifying Facilities ("QFs"). The rates for such purchases from QFs must be just and reasonable to the ratepayers of the utility, in the public interest, and must not discriminate against co-generators or small power producers. Rates also must not exceed the incremental cost to the electric utility of alternative electric energy (also known as the electric utility's "avoided costs"). New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities, 114 FERC ¶ 61,043, P 8 (2006); see also 18 C.F.R. § 292.304(a).
PSE	Issues regarding preemption and conflicts between federal and state laws are generally fact-specific, and thus, difficult to answer in the abstract. Certain state rates or incentives could be found to violate PURPA or Federal Power Act (FPA) provisions. These issues can be complex. Existing avoided-cost standards must be addressed in state programs in a manner consistent with the intent and requirements of PURPA and the FPA. As a case in point, California adopted a feed-in tariff for combined heat and power under Assembly Bill (AB) 1613 in 2007. California utilities challenged such legislation before the FERC. On October 21, 2010, the Federal Energy Regulatory Commission issued a declaratory order-responding to AB 1613 indicating that states do have the flexibility to implement feed-in-tariffs at the state level, but must do so in a manner consistent with the framework of PURPA's avoided-cost provisions. FERC denied rehearing on January 20, 2011. The California Public Utilities Commission is currently considering further utility petitions for modifications that assert that state policy violates PURPA's avoided costs standard. Bills have also been introduced in the U.S. Congress regarding these issues. Accordingly, specific state programs affecting rates must be reviewed for consistency with federal standards.
PacifiCorp	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.

	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.
NW CEAC	There are several ways to fix PURPA and Power Purchase Agreements in WA. PURPA-based PPAs should be for up to 20 years and up to 10 MW. A number of projects are inhibited by WA's approach to PURPA/PPA implementation (limits as low as 1 MW and for only 5 years). This limited approach kills good distributed energy projects in dairies, forest products and food processing facilities. These are projects in the 1 to 10 MW range. One cannot get long term financing on a 5 year PPA. Both the Oregon and Idaho utility commissions have superior approaches. In Oregon, Docket UM 1129 established long-term contracts (up to 20 years) for all Qualifying Facilities (QFs), standard contract forms for QFs up to 10 MW, and standard avoided cost rates for up to 15 years for QFs no larger than 10 MW (with the option of partially fixed rates in years 16-20), among other provisions. In Idaho, baseload CHP systems such as larger dairy digesters sized in the 1 to 4 MW range benefit from the up to 10 MW and up to 15 year PPA ground rules. This is a core problem for distributed generation in WA. It is within the purview of the WUTC to make major improvements.
NWEC	Taxpayer-funded incentives are not affected by the Federal Power Act or PURPA, whether the incentives are delivered up front, as tax credits, or as production-based incentives akin to a feed-in tariff. These federal laws restrict only incentives that are structured to set rates for sale of electricity to utilities, as classic ratepayer-funded feed-in tariffs do. Authority to set rates for sale of electricity to utilities—normally reserved exclusively to FERC by the Federal Power Act (FPA)—is granted to states pursuant to PURPA. PURPA requires utilities to acquire certain types of generation, including small renewable generation, and allows individual states to set the rate for that electricity at the utility's avoided cost. States cannot set rates for sale of electricity that exceed the utility's avoided cost. However, FERC recently clarified that, when a state legislature has required utilities to procure a specific type of generation, the state can set a special avoided cost unique to that type of generation. *See Cal. Pub. Util. Comm'n,* Order Denying Reh'g, 134 F.E.R.C. ¶ 61,044 (Jan. 20, 2011). For example, if a state law requires utilities to acquire a certain amount of generation from solar facilities, the state is authorized to set a separate avoided cost rate for solar resources. Net-metering is another way to establish a ratepayer-funded production-based incentive while avoiding FPA restrictions. Net-metered power offsets a customer's generation, so is not a sale of electricity to a utility. A bid system, which lets the parties establish the rate, is another way in which the state can avoid setting the rate for sale of electricity; however, sellers may be required to obtain FERC permission.

WALEA	Recent rulings in CA show that the UTC has a lot of leeway, especially if the state passes a distributed generation requirement. During rulemaking for Oregon's Solar Pilot Program at the PUC, it was discovered that Section 210 of PURPA prevents states from setting prices that utilities must pay for wholesale renewable energy at above avoided cost. Avoided cost is typically equated to the highly subsidized cost of energy from fossil fuels like natural gas and coal and is much lower than the cost of generating electricity from renewables. Only the Federal Energy Regulatory Commission can set wholesale prices for RE. This is known as the "FERC pre-emption". The program design chosen by the PUC for the Solar Pilot Program to avoid FERC pre-emption provides a disincentive to maximize solar production. It limits the maximum size of an installation at a given location to less than the customer's annual consumption and will not pay the fixed rate above avoided cost for production in excess of consumption in order to avoid the possibility of a wholesale sale by the customer to their utility at above avoided cost. This constraint creates a perverse incentive for the customer generator to over-consume energy in order to maximize their production payment, and creates a disincentive to adopt energy efficiency measures. Recommendations: • STATE: Amend statute to include a 100% purchase guarantee. • FEDERAL: In a case brought by California's PUC, FERC recently ruled that PURPA does allow states to set wholesale prices for RE at above avoided cost, but the case was appealed by CA's utilities. An amendment to PURPA would fix the problem. Both Senator Wyden and Senator Sanders will introduce amendments this session. Senator Wyden's PURPA PLUS Act sets a project size cap of 2MW, which is too low and if the FERC decision is not upheld, would prevent the application of FITs to large wind, solar and probably wave nationwide. Twenty other states have FIT bills somewhere in the legislative pipeline and will encounter the same problems Oregon has. We need a fix that works for everyone and frees states to decide what mix of RE technologies and project sizes best fits their needs.
CPG	If a state has a renewable requirement under PURPA authority ([CPG doesn't] believe any do right now), avoided costs are no longer solely based on the one and only least expensive generation unit. FERC stated that "[If] a state required a utility to purchase 10 percent of its energy needs from renewable resources, then a natural-gas fired unit...would not be relevant to determining avoided costs for that segment of the utility's energy needs." In other words, in states that decide to create a new renewables requirement under PURPA, renewable generation can have an avoided cost that is distinct from the general system mix. It is important to note that RPS policies are mandates under state law (not under PURPA), which means the FERC ruling would not apply directly.

A9. 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?	
Avista	The high costs and relatively limited nature of these resources would likely prevent distributed generation from being built under least-cost planning guidelines, although these resource types should be considered in an Integrated Resource Planning (IRP) process. Under the current state of the technology and costs of distributed resources, the only way distributed generation is likely to be constructed is as a pilot project, with the aid of significant grant money, or through government mandates. In many other areas of the country distributed resources are being tested. Further testing in Washington will be of little value until other states have completed their projects and potentially helped to drive costs down. The state should not depart from least-cost planning principles and rules as a matter of practice.
PSE	For customers adopting a distributed generation application, they are not making a least cost wholesale electric supply decision. They are making a consumption choice like a home improvement, or an economic choice compared to electric service at all-in grid rates, not wholesale power rates. The key point being, that customers want and are increasingly requesting power supply options that are both clean and economic to them. Policies that encourage distributed generation development and adoption should be considered generously until such time as penetration rates help clarify the operational and cost allocation issues proposed to the distribution system. Like energy efficiency, distributed generation is best addressed in the context of loss of load effects and the need to evolve the rate making framework to provide for timely recovery of, and on, distribution system investment and its operating costs.
PacifiCorp	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.
NW CEAC	Distributed Generation resource costs vary in a number of ways: 1. Some technologies are in early in their commercial life span, and others, such as CHP, more mature. The thermal benefit of CHP projects should be recognized (a cost allocation standard based on the ASHRAE energy allocation between power and heat, for example), and 2. Project location has least cost impacts. Projects located at the electrical and thermal load needs in Western WA should have a location benefit

NWEC	Pursuing distributed energy is supported by statute and Commission rules regarding resource acquisition. In 2006, the Legislature enacted RCW 19.280, requiring utilities to develop integrated resource plans (IRP) with a focus on a portfolio of resources available at the "lowest reasonable cost." The statute defines lowest reasonable cost as: "…the lowest cost mix of generating resources and conservation and efficiency resources determined through a detailed and consistent analysis of a wide range of commercially available resources. At a minimum, this analysis must consider resource cost, market-volatility risks, demand-side resource uncertainties, resource dispatchability, resource effect on system operation, the risks imposed on the utility and its ratepayers, public policies regarding resource preference adopted by Washington state or the federal government, and the cost of risks associated with environmental effects including emissions of carbon dioxide." (RCW 19.280.020(11)). Prior to the enactment of the IRP statute, the Commission had updated its rule requiring least-cost planning to accomplish much of what the legislation ultimately required for investor-owned utilities. Important to note is a shift from the traditional notion of a least-cost plan, i.e., "a plan describing the mix of generating resources and improvements in the efficient use of electricity that will meet current and future needs at the lowest cost to the utility and its ratepayers." While the current planning requirement still references a lowest cost mix of resources, it specifies that utilities must consider a variety of risks as well as public policy directives. In its final order adopting the rules, the Commission agreed with certain commenters that "a measure of risk should be weighed with the cost." Key components in the definition of lowest reasonable cost include analysis of *a wide range of commercially available resources*; *risks*; and *public policies regarding resource preference*. A host of distributed energy technologies, including solar PV, small wind turbines, and anaerobic digesters, are commercially available. Pursuit of these resources can reduce stress on the transmission and distribution system and enhance our energy security, both of which constitute risk reduction measures. In addition, distributed energy resources provide flexibility in response to changing market conditions, i.e., due to their small sizes and short construction lead times compared to most types of larger central power plants. Further, Washington State has adopted various public policies favoring distributed energy resources, some of which are referenced here. [For a list of example policies, see Comments of the Northwest Energy Coalition, p. 5-6] Finally, PacifiCorp's 2011 Integrated Resource Plan evaluates various forms of distributed generation using traditional utility planning principles. Several forms of distributed generation were found to be cost effective, including solar hot water and, with certain modeling assumptions, a Utah solar PV incentive program.
WALEA	Providing simple standard rates and interconnection procedures reduces costs

	by providing certainty (decreasing risk) for developers of distributed generation. If incentives are administered separately from rate making then this issue can be avoided. Least cost related to RE and energy efficiency measures could mean the least subsidy necessary to incentivize public investment in RE, like the price point that Oregon is trying to identify. It still represents the difference between widespread buy-in and not, i.e. necessary cost of RE.
FPNW	Distributed generation can be purchased without departing from least-cost planning principles if utilities honestly and objectively assess the value of electricity delivered on local feeders. Acquiring this electricity avoids the need to invest in additional power plants, transmission lines, substation upgrades, and other significant expenses.
CPG	Least-cost planning has been a useful tool in the regulated energy industry and has been successful at keeping rates low. It has helped us to build a competitive local economy and allows large generation resources to come to grid and provide a return on investment for independent power producers. It does appear, however, that least-cost planning may not be the best tool for the future - simply because it is too limited in focus and does not take into account important considerations such as climate benefits or grid-support. Least-cost planning should be renamed "most-benefit planning" (silly name but concept is valid) and should include a matrix of decisions that are classified as 'costs' or 'benefits'. Those resources with the highest "benefits" will begin contract negotiations, whereas ones that demonstrate 'costs' to the region will not be considered (i.e., significant emissions avoidance costs).

A10. 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? 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? 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?	
Avista	To the extent that the Commission changes the avoided cost methodology for certain types of renewable resources, the guiding principle should be to ensure that the avoided cost rate is just and reasonable and does not exceed actual avoided cost. Developers of QFs using certain technologies, most notably wind QFs, have taken advantage of published avoided cost rates by disaggregating large projects into smaller projects. Some states have attempted to adopt certain criteria, such as enhanced separation requirements and ownership restrictions, to prevent such disaggregation. Most recently, the Idaho Public Utilities Commission ("IPUC") considered adopting factors to prevent disaggregation. Ultimately, the IPUC found that attempting to prevent disaggregation without addressing the avoided cost rate was not practical. Order No. 32262 (issued in GNR-E-11-01 on June 8, 2011).

	It is the Company's understanding that there is some precedent for imposing a cap. With regard to a carve-out for certain technologies, it is permissible to treat different resources differently under PURPA. See 18 C.F.R. § 292.304(c)(3)(ii) (stating that the published avoided cost rate can differentiate between different technologies). For example, the IPUC recently imposed a different published avoided cost rate eligibility cap for solar and wind resources (100 kW) in order to prevent developers from disaggregating such resources to take advantage of published avoided cost rates. See Order No. 32262 (issued in GNR-E-11-01 on June 8, 2011). That said, any such carve out is subject to the requirement that the rate paid by the electric utility is just and reasonable to the ratepayers of the utility, in the public interest, does not discriminate against co-generators or small power producers, and does not exceed the electric utility's avoided costs.
PSE	• In general, ratemaking practices and policies that encourage alternative energy supply and their retail deployment should be generously considered. Policies which favor the reduction of reliance on large, environmentally intrusive technology such as conventional nuclear and coal plants and mega hydro projects merit consideration. Such projects have 'long-tail' liability attributes often unable to be measured and reflected in current rates, but will eventuate as the useful life of such technology comes to an end. Site remediation, decontamination and decommissioning and de-construction costs of such projects will be material. The intergenerational equity issues of such technologies are not insignificant. Emerging distributed generation technologies may harbor fewer such long term costs and risks and their development and application should not be unduly burdened by conventional least cost assessment standards. At present, there is no apparent need to fix caps or impose other arbitrary limits on distributed generation technology use. • If the commission were to change the avoided cost methodology for certain types of renewables, we would favor a cap by utility and a specific carve out by technology. Washington could learn much from the California experience where a variety of policies and financial incentives exist to foster the development of distributed renewable resources cheaper, better, and faster.
PacifiCorp	*[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?]* • 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. • 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?]* 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?]* 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 PURP A. 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.
NWEC	We are not presently in a position to comment on specific approaches to changing the avoided cost methodology for renewable resources. We note that various parties are analyzing the development of a generic renewable avoided cost in Oregon Public Utility Commission (OPUC) Docket No. 1396, and some principles discussed there may be helpful as the Washington Commission considers this issue. At this stage of developing FERC precedent, technology-specific avoided costs are likely permissible only if state laws require utilities to procure generation from those specific technologies. (See response to Question 8, above.) Under this logic, establishing a carve-out in the state's renewable portfolio standard (RPS) for specific technologies, such as solar PV, could provide the basis for a technology specific avoided cost rate. Absent such laws, all renewable technologies would have to be treated equally in setting an avoided cost rate. Finally, the Commission would need to consider what impact a change in the avoided cost methodology would have on the identification of cost-effective conservation.
WALEA	• The Commission's job is to ensure consumer protection, part but not all of that is avoided cost resource acquisition. Very real costs and benefits though are not currently included in our rate setting. Most notably is the cost/impact of global warming and the dire need to produce much more than 15% of our electricity from renewable resources. Another major figure

	not in the equation are the benefits of local economic development to be gained though distributed energy production. WALEA believes that certain benefits should be incorporated into avoided cost rates that are not currently (resource diversity/capacity, avoided transmission and distribution upgrades, avoided new fossil generation, decreased fuel price risk), these should be wrapped up in an avoided cost structure that gives distributed generators full and fair pricing for all benefits under the authority of the UTC and available to all distributed renewable technologies. • Other benefits should be paid for outside of the rate structure with a system benefit charge, our current cost recovery incentive, or another mechanism. These benefits include (greenhouse gas reduction, local economic benefit, job creation, energy security, technology development). These benefits could be compensated in a combination of incentives such as the cost recovery incentive that target desired technologies and modes of implementation but a more flexible method of targeting incentives and maximizing benefit per incentive dollar spent should also be created.
CPG	Avoided cost methodology seems relatively straightforward with the recent FERC rulings on using new natural gas generation as the 'baseline' to avoid. Renewable energy 'backs-out' fossil generation, which receives a 'climate credit' for doing so. Renewable energy avoids two things: fossil fuel generation costs, and environmental remediation costs from that fossil fuel generation. Energy efficiency and conservation should always be the 'priority' resources, as it avoids ALL generation whatsoever ("the cheapest MWh is the one we don't use"). • Yes, there should be carve-out for specific technologies - and it should be based on the "most-benefits" concept explained in the previous answer. Projects that show the highest number or quantity of benefits should be prioritized for project development. Also, technologies that produce thermal AND electric resources should have a higher priority than electric-only or thermal-only ones. • Suggested prioritization list: 1. Combined heat and power (energy efficiency) 2. Urban-area district energy systems 3. Urban-area solar thermal and solar electric 4. Urban-area waste to energy (costs are still high) 5. Rural renewable energy production 6. Rural fossil-fuel energy production

A11. 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?	
Avista	The avoided cost rate is the incremental cost to the utility of alternative electric energy. Therefore, if the alternative to purchasing the output of a QF is for the

	utility to develop and own a similar facility, all incentives available to the QF should be considered in setting the avoided cost rate. For example, if a QF produces RECs, the value of those RECs should be considered when establishing the avoided cost rate for such facility because, if the utility were to develop and own a similar facility it would own the RECs associated with that facility.
PSE	Customers adopting distributed generation technology are not evaluating the cost of alternate utility-scale supply options, only the alternative cost of grid power purchases to them. However, were a utility to consider distributed generation as an alternative to energy efficiency or a utility-scale supply option, it would be appropriate that state or federal incentives be included in the calculation of avoided cost, but only if, such distributed generation investments were intended for the utilities general supply portfolio and not limited to a subset of customers who might elect a special tariff providing for a specialized solar service.
PacifiCorp	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.
NW CEAC	They should be included in the analysis. They should not be treated as though they don't exist.
NWEC	The avoided cost must reflect the amount the utility would spend to obtain the output and capacity from a market purchase or from developing its own generation facility. *See* 18 C.F.R. § 292.304. Therefore, there is an argument for offsetting the avoided cost rate for renewables with policy incentives. However, policy incentives are so volatile that an avoided cost rate that relied upon them would have to include an adjustment mechanism that automatically eliminated policy incentives from the rate upon their expiration.
WALEA	Avoided cost should not have to do with other incentives at all if we are talking about avoided cost to the utility for the services provided by the distributed generation. From the perspective of effectively incentivizing distributed generation these incentives should be most certainly factored in, the state should leverage federal and other dollars as much as possible to reach its goals. To that end policies should be designed to allow participants to easily access all incentives. For instance the current community solar rules make structuring community solar projects quite complicated for non-utility developers adding significantly to the cost of these projects. Often a change in the structure of a program can multiply the effectiveness of the dollars in that program.
CPG	The FERC is currently reviewing avoided cost methodologies and incentive structures and should be consulted if any plans are developed in Washington State. Tax benefits and grants should NOT be counted in avoided cost of energy production. Grants and tax benefits act as a 'financial bonus' to the project developer and are a functional part of the marketplace.

<table>
<tr><th colspan="2">A12. For both capacity and energy, how does the current cost of building distributed energy technology compare with other available resources?</th></tr>
<tr><td>Avista</td><td>Avista's 2009 electric IRP reviewed the cost of distributed generation for wind, solar, wave, and hydrokinetics. Each of these resources was found to be more costly than traditional resources and was not selected in Avista's Preferred Resource Strategy. The only distributed generation resources likely to be cost competitive are landfill gas, manure/solid waste digesters and co-generation. The limited numbers of these projects are indicative of the market not being able to support them. No distributed generation resources were successful in any Avista renewable requests for proposals. If the cost of distributed generation becomes cost effective as technology improves and costs decrease as manufacturing scale increases, the market will start to support increased construction of these types of resources by utilities or by third-parties.</td></tr>
<tr><td>PSE</td><td>Levelized energy cost ($/MWh) estimates for various generating technologies. Estimates include applicable Federal and State subsidies.
<table>
<tr><th>Technology</th><th>Distributed Generation ($/MWH)</th><th>Utility-scale ($/MWH)</th></tr>
<tr><td>Wind</td><td>$150 - $250</td><td>$75 - $125</td></tr>
<tr><td>Solar</td><td>$400 - $600</td><td>$175 - $225</td></tr>
<tr><td>Combined Heat and Power</td><td>Unknown; often a "one-off" consideration; complex business models</td><td>$100 - $200</td></tr>
</table>
In summary, distributed generation technologies in several and ever more numerous jurisdictions, are becoming less costly than grid power purchases by the customer. Distributed generation is becoming an important customer choice. However, at present, most distributed generation applications in the Pacific Northwest are more costly than utility-scale plants in terms of levelized cost. In addition, it is important to note that wind provides very little firm capacity value and solar provides no firm capacity value. Just as the wireless telephone device eroded the use of wire-based land-based telephone systems, so too might distributed generation reduce dependence on large central generating stations delivered over the ever more costly distribution system.</td></tr>
<tr><td>PacifiCorp</td><td>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.</td></tr>
<tr><td>NW CEAC</td><td>Costs and capacity vary widely by type of technology. An analysis should distinguish between baseload resources and intermittent.</td></tr>
</table>

WALEA	It depends on which incentives and subsidies for conventional resources are counted and which incentives and subsidies for distributed renewable resources are counted. Not counting the cost recovery program and assuming non cost related barriers to development of distributed energy resources are removed most technologies are in the same ballpark as simple cycle natural gas (with the exception of solar PV). This emphasizes the need for fair market access and barrier removal legislation. It also emphasizes that incentive dollars can go quite a long way bridging the small remaining gap rather than trying to compensate for all barriers by just throwing dollars at the issue.
FPNW	The cost of producing electricity from many distributed energy technologies is already below the retail price of electricity. Unfortunately, these technologies lack the market stability provided to incumbent resources such as natural gas-fired power plants owned by utilities; thus, for lack of stable contracts and the stable financing these contracts can bring, distributed generation is rarely built even in cases where it compares favorably with other resources.
CPG	There is an important distinction between rural area renewable energy plants and urban area distributed energy - rural area renewable energy plants generally produce energy; whereas urban area distributed energy produces capacity. IREC correctly characterizes Washington state as not having taken advantage of 'low hanging fruit' for distributed energy - evidenced by the surplus energy (and negative pricing) yet lack of capacity to move the power from point A to point B (except when exporting to California due to higher transmission investments and newer equipment) throughout the BPA system. *Combined Heat and Power and Waste Heat Recovery* Cost of CHP: • *Total Costs to Generate Power ($/kWh) = $0.0618 / kWh* - EPA CHP example: http://www.epa.gov/chp/basic/economics.html • Of the various energy streams produced by a CHP plant, the highest value output is electric power, next in value is heating and cooling is lowest value output based on typical utility costs and generator, boiler and chiller efficiencies [see table, p 9] Cost of Waste Heat Recovery: • Implementation cost: $30,000 to $75,000 per MMBtu recovered heat (includes normal installation). Site specific. Typical payback periods –one year to three years

A13. 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)?	
Avista	The costs associated with interconnecting distributed generation vary with each system. At a minimum the cost is a production meter; at maximum the cost is a dedicated feeder and ancillary equipment to integrate the generation resource.

	These costs presently are and should continue to be paid for by the customer-owners of distributed resources.
PSE	For customer-owned distributed generation, the interconnection costs of UL 1741-protected systems is not material to the customer, typically a few hours of time for a qualified electrician. Under state and federal law, the developer/owner of the system who will benefit from the system pays for the costs of interconnection. Related utility administration costs (such as the five employees helping coordinate net metering programs) are currently paid for by all customers per UTC Order in Docket No. UE-990016. Distributed generation may not save money on the distribution system if the distributed generation has intermittent characteristics and, consequently the distribution system has to be designed to reliably operate when the distributed generation is not generating.
PacifiCorp	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.
NWEC	There are material costs associated with the interconnection of DG that can vary based on a project's size or specific needs. Typically, the interconnection costs are minimal and the socialization of those costs can be justified by the added benefit brought to the grid by the DG system. If the cost is borne by the customer, an assumed integration cost should be included in the calculation of an appropriate incentive level. IREC has provided multiple solutions in its comments for decreasing the costs of DG interconnection and streamlining the process.
WALEA	Direct interconnection costs (line extensions, switch gear, meters, etc.) should be borne by the distributed resource owners, this puts the proper incentive on the developer to plan projects where they most cost effectively integrate with the grid. Costs of making the distribution system ready for distributed generation (direct transfer trip relays, substation metering improvements, billing software upgrades, system switching, etc.) should be socialized as part of a plan to make local generation commonplace, rather than be borne by the first generator to interconnect to a distribution system.
DNRP	The marginal costs of an interconnection requirement require labor hours and certain pieces of equipment. This will be a multiplicative cost base on the number of distributed energy facilities that are connected. As this cost is based on the necessity to connect a system for localized use, we believe that it should be borne by customer-owners of the distributed resource.
CPG	Protection costs should be borne by the utility company and not the customer or

	project developer. Interconnection requirements should be relevant to today's energy industry standards and best practices, and should NOT have significant shortcomings that impede the facilitation and deployment of distributed energy resources onto the grid. Many substations and utility feeders do not have the same protection required by customer generators (i.e., dual protection and relays).

A14. Should the current statutory restrictions on the size of distributed energy resources be changed? If so, please explain the reasons for the suggested change.	
Avista	In 2011 an Avista internal distribution system study confirmed the broad conclusions of an earlier 2001 EPRI study. Based on this information, Avista believes that interconnected resources exceeding 5% of light load-hour demand on any distribution feeder should be evaluated on a case-by-case basis, with the resource owner being responsible for any facility upgrades necessary to maintain system reliability.
PSE	The definition of what constitutes distributed energy resources merits careful consideration before making changes. If net metering were increased to 300 KW from 100 KW, it would still allow the low-cost interconnection projects. However, this 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. For example, a new school with 350 KW solar is interconnected and utilizing PSE's fixed-offer contract under Schedule 91. A proposed net metering limit greater than 300 KW will encounter more complex and costly issues of safety and power-quality.
PacifiCorp	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.
NW CEAC	The net metering law should be raised to 2 MW to benefit commercial and small industrial customers.
NWEC	Distributed generation can be defined in terms of connection and location (e.g., generation units installed close to the load or at the customer side of the meter) or in terms of generation capacity (e.g., 1 kW to 20 MW or more). Washington statute does both: ▪ The Energy Independence Act (I-937) 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." ▪ The Net Metering statute includes certain facilities with "an electrical generating capacity of not more than one hundred kilowatts." ▪ The Cost Recovery Incentive Mechanism does not cap the amount of production from a renewable energy system contributing to customer-generated electricity (instead placing a cap on the maximum amount of incentive paid annually to each customer-generator), but does cap a community solar project at 75 kW. ▪ The sales and use tax exemptions for machinery and equipment used in generating electricity from renewable energy sets a threshold of at least 1 kW, and a maximum for solar of 10 kW. ▪ The Emissions Performance Standard defines distributed generation 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." No specific size limit is provided. ▪ RCW 35.92.360 and RCW 54.16.280 expand the definition of conservation for municipalities and public utility district financing purposes to include "the on-site installation of a distributed electricity generation system that uses as its fuel solar, wind, geothermal, or hydropower, or other renewable resource that is available on-site and not from a commercial source." Again, no specific size limit is provided. For simplicity and clarity, we believe the size threshold associated with distributed generation in I-937 is appropriate, and for consistency, we recommend raising the size of eligible net metering systems to 5 MW. In conjunction with that change, we recommend increasing the cumulative cap for all net-metered systems from the current level of 0.5% of the utility's 1996 peak demand to at least 5%. That modification is critical to ensure the potential for broad participation, and to ensure that larger commercial and industrial systems don't occupy all of the allotted capacity leaving residential systems stranded. We note that several states have placed no limits on the aggregate amount of net-metered systems (e.g., AZ, AK, CO, CT, FL, Iowa, LA, ME, MN, MT, NM, NC, ND, OH, OK, OR for IOUs, PA, WI, WY), an approach we prefer. We also recommend increasing the minimum allocation reserved for net-metered systems powered by renewables from one half of the total allotment to at least three-fourths of the total allotment with an increase in the size of net-metered systems.
WALEA	• Distributed generation is of a size that connects to a utilities distribution system, not the transmission system. The current definition of renewable resources 5 MW and under is sufficient and suitable but that number could go slightly higher, perhaps up to 10 MW, and still meet the common sense definition of distributed. For example, Coastal Community Action's 6 MW wind project in Grayland, WA should be considered distributed. • The use of 'average MW' or other ways of shoe horning distinctly non

	distributed projects into this category should be avoided, and those stewarding the policy should be on guard for them. • As far as technology all renewable resources under 5 MW (or whatever the limit is) the current definition is good but eliminates certain types of hydro power (which can actually have the lowest impact per MWh of any technology ironically, but are caught up in water politics) • This is a central theme for WALEA; all renewable resources should be included in distributed generation policy. We recognize that different technologies have different impacts but their impacts should be addressed in legislation addressing the impact rather than excluding that technology from being renewable.
CPG	• Yes the cap should be raised to 2MW. The 100kW limit placed on net metering systems is insufficient to incentivize industrial and commercial investment into efficiency technologies such as Combined Heat and Power. Furthermore, it is insufficient to allow institutions such as schools and public agencies to offset their own energy consumption. The purpose of the existing cap on capacity is to prevent excess export of electricity from customer generators onto the grid, but it is also preventing larger load consumers from offsetting their use. A cap of 2MW would be more appropriate, with the recommendation of limiting the customer's energy production to the annual use of the customer (i.e., no export). We also support the recommendation to raise the utility company cap from 0.5% to 5%. • We do not believe the definition of the term "distributed generation" should include projects that directly tie to the transmission grid, and are over 2MW in size.

A15. Can each distributed energy resource be used to support emergency management practices in addition to electricity generation?	
Avista	No. Distributed energy resources do not provide viable support for emergency management practices because the Company does not have control over the distributed energy resource and is therefore unable to operate the facilities in a manner supporting emergency management practices.
PSE	If PSE has distributed generation facility dispatch capability, then the resource can help with circuit load management practices, and possibly support in an emergency. Solar and wind cannot help because they cannot be "turned on" while biogas and biomass cannot help in an emergency because they are already on.
PacifiCorp	In order to respond to this question, PacifiCorp would need to better understand the Commission's definition of emergency management practices.
NW CEAC	*Combined Heat and Power* A hard lesson learned can be taken from Hurricane Katrina. Those hospitals with CHP systems that could be islanded continued to function. Those that

	lacked these systems failed and required major rebuilding due to mold. It is essential that utility interconnection agreements enable islanding for emergency facilities.
NWEC	The ability of DG to support emergency management practices is another complex issue that should be informed through a comprehensive and robust analysis. It is quite possible that by contributing capacity at times of peak demand, DG systems could help to avoid grid blackouts. For example, because of the strong correlation between temperature, air conditioning load, and solar PV output, solar PV is well matched to help prevent blackouts during heat waves. It has been demonstrated that a sizeable amount of distributed PV could prevent the types of cascading power outages seen in both the Western System Coordinating Council (WSCC) blackouts in the summer of 1996 (which originated on BPA lines in Oregon) and the summer of 2003 blackout in the Northeast. The cascading failures that caused the Northeast blackout, which lasted multiple days and is estimated to have generated costs of nearly $8 billion, could have been avoided with 500MW of distributed PV in the region. Due to its ability to alleviate market stresses and thereby prevent grid failures, the contribution made by DG to enhanced grid security should be appropriately valued as part of a comprehensive integration cost analysis.
CPG	Yes, as demonstrated by various end-users (telecom, federal government, financial industry and many other case studies that are widely available on the internet) - onsite distributed generation is critical to the emergency management functions required by various groups. Existing standby diesel generators are an excellent example of distributed emergency generation. If we could utilize these existing generators with a "clean" fuel then perhaps we could run them 24/7 and use the grid itself as a backup system in case the "clean"-fueled generator goes offline. Even better - the "generator" can be a hydrogen fuel cell, or an electric battery, or a combined heat and power setup.

A16. 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.	
Avista	We are not aware of other viable technologies to consider at this time
PSE	The Company believes that the aforementioned list of resources is fairly comprehensive. We also recommend that consideration be given to emerging combined heat and power applications. For example, Honda has developed a natural gas-fired combined internal combustion generator-home furnace combination that can deliver extremely high efficiency heat and power delivery on a distributed scale. Bloom Energy is commercializing a natural gas fuel cell that would deliver both heat and power to businesses and residences, if successful. These types of combined heat and power technologies are in various states of development and commercialization.
PacifiCorp	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 [see 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 [see 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%**

NW CEAC

1. Fuel cells – Commercial stage, price is declining but still expensive
2. High solids digesters – Commercial Pilot Stage, European technology is expensive; WSU technology is much cheaper and ready for the first commercial pilot scale digester to be built;
3. Northern climate dairy digesters – Mature technology, the WSU low cost nutrient recovery system is now commercial.
4. Biogas stirling engines – Early commercial stage
5. Microturbines – Mature commercial, however, there is only one project under development in WA – Juanita High School in cooperation with PSE;
6. Combustion and steam turbines – mature technologies;

	7. Wood waste CHP systems are part of the Washington Department of Natural Resources pilot/demonstration system. 8. Organic Rankine Cycle/waste heat recovery – Mature technology, however, none have been built in WA
WALEA	High efficiency combined heat and power (CHP) applications for renewable and non-renewable fuels should be considered for qualification. It is apparent that natural gas and other gaseous fuels will continue to be a big part of our energy supply and so an efficient use of these fuels would be prudent for the environment and the economy. Including applications that make dramatically better use of the energy available in gaseous fuels should be encouraged along with the rest of distributed energy policy through a discounted incentive, or a separate policy should be thought through.
CPG	CHP and district energy systems are essentially "fuel-agnostic" and are simply efficient delivery systems of thermal and electric energy. Which "fuel" is put into the CHP or district energy system is secondary and is usually a consideration of available local resources. So, for Seattle we would use a district energy system fueled by the sun, biomass, natural gas, and lake-cooling. The district energy system would provide the "efficiency" tag, and the fuels would provide the "clean" moniker. This is an important concept that is largely overlooked in the development of our urban infrastructure.

B. Technology-Specific Issues:

Distributed Solar

B1. 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?	
Avista	Our Company's most recent experience with solar proposals have not included itemizations of the photovoltaic module and other balance of plant costs. Traditionally, an uninstalled module would account for roughly half of the total installed cost. A typical distributed solar system ranges from \$4,000 to \$6,000 per installed kW. Energy production over 25 years with a capacity factor of 12 to 15% would equate to a \$300 to \$550/MWh levelized energy cost. Larger multi-MW systems may be in the \$2,000 to \$3,000 range with levelized costs in the sub \$200/MWh range. It is safe to say that larger photovoltaic systems can generally utilize economies of scale to reduce module, inversion, installation and other ancillary costs. Other factors may have a more pronounced effect on the overall economics of solar installations. Ownership, financing and associated accounting and procedures have a significant effect on project economics. To the extent that a non-utility developer may be able to finance the project through a highly-leveraged debt deal, for example, the total cost of the non-utility project may be less than a utility sponsored project.

	There are many other variables that would affect the total cost, such as cost and availability of land, cost of the interconnection, etc.
PSE	PSE has received several proposals for utility-scale (> 5 MW) solar projects, but these proposals did not specifically identify the various components of installation cost. PSE does not have reliable, up-to-date, cost-to-construct data for distributed solar or new central applications. PSE's limited data agrees with the data in Table 1 [see question A1, above] which show that about one-half of the total cost is for modules, and half for installation and other equipment.
PacifiCorp [answering all solar questions 1 – 4]	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. • 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. o 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. o 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. o 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. [See tables: History of Incentive Levels; Small Systems, 10 kW and under, and History of Incentive Levels; Medium Systems, greater than 10 kW, less than 100 kW, p. 12] • 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.
NWEC	The cost of installation for both DG and utility-scale solar PV systems has fallen significantly in the past several years. In the second quarter of 2011, the average cost of an installed residential system in Oregon was $6.30/Watt, while the average commercial (not utility-scale) system cost was $6.10/Watt. However, due to continuously falling costs, many residential and commercial systems are now being priced at closer to $5/Watt. Utility-scale PV systems (1 MW or larger) are reportedly being installed at an average cost of $4.50/Watt in the US, although a third of those systems are being installed for less than $4/Watt. Due to larger installation companies being able to take advantage of high-volume purchasing, it can be assumed that the cost of solar PV modules

	for DG applications is similar to that of utility-scale applications. Therefore, the difference between all non-module costs between DG and utility-scale PV projects appears to be on the order of $1-2/Watt.
WALEA	• Most installed DG systems in the U.S. are in the range of 2 to 5 kW. The per unit cost of the installation ranges from $8-$9/watt, with $4-$5 of that being the solar panel itself. This does not include any federal or state incentives. • "With the current rate of progress, the cost of a utility-sized photovoltaic (PV) system is likely to reach $2.20/watt by 2016, and $2.50/watt and $3.50/watt, for commercial scale and residential scale systems respectively. Reductions significantly beyond that in the next four to eight years are unlikely absent dramatically new ideas and significant investment." (USDOE) • Although the per-unit cost of installed solar may be less for utility scale solar facilities, the distributed nature of the renewable solar energy is negated. The electricity surplus in Washington makes utility scale installations unwise, as well as line-losses associated with centralized electricity generation. As future electricity demand in WA rises, taking customers off the grid through utilization of distributed energy systems will be a more efficient way to meet that demand.

B2. 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?	
Avista	In general, a distributed generation system has the advantage of reducing potential line losses. The natural diversity of distributed systems tends to reduce the effects of localized sky cover and other climatic variations. Smaller net metered systems installed at the customer level require little utility integration other than a production meter and an appropriate interconnect inverter. Typical photovoltaic production profiles tend to coincide with system loads and tend to reinforce local distribution circuits. Larger distributed systems could cause operational issues in cases where feeder loading is light or they are installed at more remote locations. Each distributed system would require separate building approvals, permits, inspections, net metering calculations and utility administration.
PSE	From a system integration perspective, PSE does not anticipate that integration of distributed generation projects will be significantly different than PSE's experience associated with a utility-scale facility. With respect to interconnection, ease of integration will depend on site location and loading of the local distribution system. PSE will experience challenges associated with areas where local substations are close to full capacity. The primary issue is the relative size of the project in comparison to the circuit's ability to absorb the energy through the existing load. For example, if the generator nameplate capability is larger than one-half the minimum load, then a transfer trip would

	have to be installed, increasing total costs
NWEC	A growing body of research exists that demonstrates the considerable reductions in variability that arise from the aggregation of geographically diverse solar PV systems. Reductions in variability can occur through the aggregation of both small and utility-scale projects; the determining factor in both cases is the correlation of variability at the sites being aggregated. For example, the variability in solar radiation received by 100 solar PV systems distributed throughout 10 city blocks would likely have a higher correlation than the variability seen in 100 solar PV systems distributed throughout the state. Aggregating the systems with a higher correlation of variability would do less for reducing overall system variability because the power output of those systems would be fluctuating in unison. When sites with lower correlations of variability are aggregated, the variability of an individual site is offset by the variability of other sites, leading to less overall system variability. Therefore, the overall system variability resulting from the aggregation of the PV systems distributed throughout 10 city blocks would be greater than the overall system variability of the 100 systems distributed throughout the state. Likewise, the aggregate variability of utility-scale PV systems is reduced through the presence of systems with lower correlations in variability of solar radiation. Another question that must be considered when analyzing the integration of solar PV is the net effect of the interaction between solar PV variability with other sources of variability already on the grid, including load and wind. This issue is typically addressed through a reserve requirement analysis, which identifies that amount of generating reserves that are necessary to accommodate the integration of a given amount of variable resources. RNP prepared a report that addresses issues associated with solar PV variability and integration and provides a review of current PV integration literature.
WALEA	Yes, in distributed production of PV the variability disappears within the variability of loads and existing infrastructure can handle significant levels of penetration. Sharp changes in output due to clouds passing over are entirely smoothed out on a regional basis due to geographic distribution. Even the daily distribution is flattened somewhat due to variable installation angles to the sun across multiple installations. No transmission capacity is required for distributed PV production, and costly storage expenses are avoided to remedy the fluctuations in power output.

B3. Are there lessons learned from Oregon's tariff subsidies for solar installations? Is there a calculated subsidy per kWh for the Oregon program?	
Avista	The Company is aware of legislation (House Bill 3039) that was enacted to establish a pilot program, beginning in January 1, 2010, for solar photovoltaic

	generation of up to 500 kilowatts by retail electric customers and a utility-scale solar mandate requiring electric utilities in Oregon to generate a statewide total of 20 megawatts from solar systems ranging in size from 500 kilowatts to 5 megawatts by January 1, 2020. Furthermore, the Company is cognizant of Oregon's renewable energy tax incentives, offered under its Residential Energy Tax Credit and Business Energy Tax Credit programs, and the fact that these incentives have been revised recently. Nevertheless, as a natural gas supplier only in Oregon, we are not involved enough in all of these programs to offer any insightful comments on them at this time.
PSE	In the era of fiscal stress, the Oregon Legislature has determined to reduce solar subsidies by 99 percent, to $3 million from $290 million. Second, one might conclude that initial incentive rates were "too high" based on the high volume of customer interest. The initial offering, when the incentive was about 60 cents per kWh, was promptly subscribed. When the incentive was dropped to about 40 cents, the customer response rate was similar. Oregon has not yet found the rates that will promote steady development of distributed solar.
NWEC	The main lesson learned from the Oregon solar FIT program is that the initial incentive rate was set too high. The unnecessarily high rate created an intense demand for the program that created hectic application processes during which available capacity for a six-month period was allocated in sometimes less than five minutes. This hectic process led some to the belief that the application system was being gamed by or used to the advantage of companies with access to sophisticated computer software capable of auto-filling the online application. Complaints over this issue led the OPUC to change the FIT program from a first-come first-served application process to a lottery-based application process. This change will likely have negative ramifications for the program and could lead to lower quality projects being awarded capacity allocations, resulting in a higher program attrition rate. As was recommended by a large group of solar industry representatives and advocates prior to the implementation of the program, the best methods for creating a stable and successful program include: setting an appropriate initial FIT rate that is not so high as to create overwhelming demand, establishing pre-determined FIT rates that decrease based on program subscription (not time), and the use of a first-come first-served application process rather than a lottery.
WALEA	Oregon's feed in tariff is a pilot project, part of an inquiry into solar development, intended to allow utilities and solar providers to find the sweet spot between up-front costs and long-term payoffs to entice solar consumers. Rates were set between 55 and 65 cents per kWh. So far, the program has proven so popular that its capacity was subscribed in just 15 minutes in the first enrollment period July 1, 2010. And efforts to revise the rates downward have yet to slow traffic. Rates were reduced by 10 percent in October 2010, again filling up in under an hour. In March, rates were revised downward by another 20 percent, landing between 39.6 and 46.8 cents per kWh for the enrollment period that opened in April, with similar results.

	With similar electricity prices in WA ($0.08-0.085/kWh) and OR ($0.085-0.09/kWh), we may extrapolate that a feed-in-tariff rate of $0.40/kWh is unnecessary. It is worth noting here that the Net Metering structure in WA only allows customers to recoup the value of the offset energy and are not paid if they produce more than they consume. California's SGIP also proves as a good example of state sanctioned equipment 'buy-down' programs.

B4. Given the variety of tax and other financial incentives for solar manufacturers and consumers, are additional incentives needed?	
Avista	While the cost of photovoltaic installation continue to trend down, lower energy costs in the Pacific Northwest make economic justification for solar energy difficult. Washington incentives and Federal tax incentives bring the gap closer, however many end use customers are reluctant to make the initial capital investment for distributed systems. Utility scale solar systems are generally not competitive with wind projects in the Pacific Northwest and therefore are not included in resource planning.
PSE	The answer to these questions depends on what the policy or implementation goals are. It is important to clarify the intent of the incentives. If the intent is to encourage local manufacturing, it probably would be more effective if structured as a direct incentive to the in-state manufacturer. The current arrangement of paying a higher incentive to the end user in the case where locally manufactured products are used has the tendency of raising the price the consumer, such that most of the incentive value is lost. Since many of the net jobs occur in the installation side, it may be more effective to target incentives at appropriate technologies, regardless of manufacturing location. Generally speaking, if the policy goals are to increase local investment into distributed generation, it would be beneficial to extend and increase state incentives for investment. Uncertainty surrounding renewal of short-term incentives typically creates market and investment inefficiencies. Long-term stability and knowledge of incentives provides investors with confidence that they will be able to meet the incentive requirements within the parameters of the timeline.
Washington State Housing Finance Commission (WA HFC)	Based on the financial analysis of DRA [WA HFC's financial advisor], solar projects, with the exception of single-family home installations using solar panels manufactured in Washington State, are not financially feasible using the currently available incentives. The State's solar energy incentives for solar PV is inadequate to support timely payback of installations for multifamily housing, commercial, industrial, and municipal (i.e. publicly owned) buildings. Moreover, the provisions governing the installation of "community solar" projects on public buildings remain difficult to use on a broad scale. The currently existing solar incentives will support payment of solar PV systems up to about 30 kW in size if the PV panels are manufactured in Washington State, qualifying for the higher incentive rate.

NWEC	Although the costs of solar PV have declined consistently and substantially over time, and especially in the past two years, state incentives additional to the Federal Investment Tax Credit (ITC) are still necessary to drive widespread adoption, especially in Washington. Besides Alaska, Washington has the poorest solar resource in the United States coupled with some of the nation's lowest electricity prices. This combination makes it difficult for solar PV to compete with conventional energy sources. However, with an appropriate incentive level, PV could flourish; Germany has a poorer solar resource than Washington and has by far the greatest amount of solar PV installed than anywhere else in the world (Appendix E). As PV costs continue to fall and electricity costs rise, incentive levels can decrease over time. For example, in California, decreasing costs of PV and high costs of electricity have allowed the state incentive to diminish over time to the point where solar PV currently requires little or no additional state incentives to be viable.
WALEA	Current incentive levels are sufficient or even generous. Restructuring of the current state incentive programs could make conditions more favorable for solar with the same or a lower incentive level. Particularly making the structuring of community solar projects easier (such as through community net metering) would decrease costs and barriers to implementation of PV technology.

Distributed Wind

B5. 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?	
Avista	It totally depends on location and size. Both types are possible but can be very detrimental to the utility. For example if there is a large quantity of distributed generation placed on one utility feeder, voltage control on the feeder may be impossible to meet ANSI 84.1 voltage standards and clearances for utility personnel to safely work on the utility system.
PSE	The national RTO and ISO experience with wind integration is clear: the larger the area of the balancing authority and the greater its reliance on and use of market mechanisms, the easier and less costly it is to integrate intermittent wind resources. Both the German and the California experience with solar integration suggest distributed technology can be integrated without significant issue.
PacifiCorp [addressing all wind questions 5 – 7]	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. 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.
WA HFC	Wind energy development in Washington State has largely been in the utility sector and has taken place on a utility scale. As such, it is sensitive to assumptions regarding operations and maintenance (O&M) costs, and the rate at which, if at all, developer equity investment is repaid prior to repayment of senior debt used to finance such utility-scale projects. Moreover, the State's renewable energy incentive, capped at $5,000 per year, is immaterial to the development feasibility of these utility-scale wind farms, with their large capital costs and repayment requirements. Most of the operating wind farms in Washington are owned by utilities which are required to comply with the State's renewable energy standard, and are able to sell the power generated at retail rates. We have not discovered a widespread appetite (thus far) for distributed wind-energy electric generation on the smaller scale, though we assume that the issues relating to lack of realistic and usable financing incentives affecting distributed solar installations would similarly affect distributed wind generation installations.
WALEA	Yes, until distributed wind capacity equals or exceeds local minimum demand, distributed wind variability can be handled by the same infrastructure that compensates for change in demand. Within any one corner of the state, the instantaneous variability in the wind is smoothed out by the geographic diversity of distributed wind installations. Valleys, shores, passes, ridges, deserts, plains all have differing seasonal and diurnal wind characteristics. Distributed generation policy encourages development in all of them rather than just the one that happens to yield the absolute greatest bulk energy per MW installed capacity.

B6. What is the estimated contribution of distributed wind generation to meeting a utility's peak demand?	
Avista	Previous Avista Integrated Resource Plans have documented that wind generation provides little if any contribution to system peak needs. Avista therefore assumes wind resources provide no contribution to meeting peak

	demands. Distributed wind generation should be treated similarly.
PSE	PSE does not expect distributed wind deployment to be of significance, and accordingly, would not expect it to provide system peak capacity. In general, we currently give wind capacity (peak demand) credit at an amount equal to 5% of its nameplate rating for planning purposes at the utility-scale level.
WALEA	OPALCO commissioned a study in 2004 studying the wind energy as a potential way to avoid a line upgrade to Orcas Island. Though the methods used in that study are not up to the standards of the modern wind industry, the results showed a significant reduction in peak demand on their highest use days. This study is included as an appendix. WALEA members have further shown with their own data that west side resources peak in the winter months. Heating is the main driver of peak load and heating need is driven by both low temperatures and high winds. Though the topic deserves further study, WALEA estimates a capacity contribution of west side wind of 20% to 60% of a distributed wind facilities rated capacity. East side winds have a low contribution to winter heating loads but a high contribution to summer irrigation loads since it is both wind and heat that generate irrigation demand.

B7. Does current distribution capacity constrain development of distributed wind generation?	
Avista	No, not at this time. The Company is still able to accommodate wind generators depending on size and location.
PSE	It depends on the characteristics of the distributed wind generation (size, etc.), where it will be located on the distribution system, and other characteristics of the system (e.g., load, other DG's on the same circuit, etc.). Modeling the system helps to review the impacts of distributed wind generation, and will identify the constraints, if any. System protection, as well as capacity, is also an important design element to ensure a safe and operable generation interconnection.
WALEA	In certain high wind agricultural areas yes distribution capacity does constrain distributed wind development.

Distributed Hydroelectric

B8. What is the state of the technology for generating electricity from wave, tidal, and micro-hydro technologies (maturation, market penetration, retail price of installation)?	
Avista	Avista has done some preliminary studies concerning the state of technology for generating electricity from wave, tidal, and micro-hydro technologies as part of the research for the IRP. These technologies have not reached the point of being commercially available for utility use because of their high cost. The prices estimated for tidal and wave generation in our 2009 IRP was $785.63/MWh for 20-year levelized nominal cost ($665.12/MWh in 2009 real

	dollars). The costs for micro-hydro (hydrokinetics) were estimated to be $147.87/MWh in levelized nominal dollars and $125.35/MWh in real 2009 dollars
PSE	Wave and tidal power are still in the experimental or R&D phase. Micro-hydro has been on the increase in 2011; however it has been limited to redevelopment of old facilities. Building a new dam or water-diversion project would be difficult now due to limited sites and environmental review.
PacifiCorp [addressing all hydro questions 8 – 10]	In the latter part of2010 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.
WALEA	WALEA considers, run of stream, dam improvement, and irrigation hydro technologies very mature and deserving of broader implementation. One of the world's premier providers of this scale of hydroelectric technology (50 kW to 5 MW) Canyon industries is in Demming, Washington and promotion of this technology will increase in state manufacturing. Ocean energy technologies are still in the development and demonstration phases and it remains to be seen which modes will prove economical.
Hydropower Reform Coalition (HRC)	Discussions about "micro-hydro" or "small hydropower" suffer greatly from the lack of consistent defining terms. There exists no clear state, regional, or national description that would distinguish micro from other forms of hydropower, other than a vague sense that it is smaller. Descriptors like "micro" or "small" are often used by hydropower developers to imply that a given facility or technology has fewer environmental impacts. However, most definitions of these terms are based on a single qualifier: a facility's nameplate generating capacity. Because there is no meaningful correlation between a hydropower facility's size and its environmental impact, these two terms are often at odds. Worse, they lead to bad policy, providing subsidies and incentives that encourage the development of facilities with significant environmental impacts, especially relative to their meager energy contribution. Rather than classifying hydropower by its size or capacity, policymakers should instead focus on methods of classification based on individual technologies (e.g. facilities that use specific types of new turbine technology), types of installations (e.g. additional hydropower capacity added to existing dams, canals, pipes, or other water infrastructure), or the environmental performance of individual facilities (e.g. those that have been certified by an independent third party such as the Low Impact Hydropower Institute). Providing a clear definition is critical if the Commission wishes to avoid policies that will encourage the worst and most damaging types of new hydropower development. There are currently nine pending or issued permits and licenses for small conventional dams in Washington State, each of which has an expected average annual generation of between 2.5 and 10 average

	MW. Each of these would be located near wilderness, roadless or high value recreational areas. Some would be located in old growth forests and/or Late-Successional Reserves, and one project is proposed to dam a stretch of river that has been deemed eligible for Federal Wild and Scenic designation, and is classified as a "protected area" by the Northwest Power and Conservation Council. Washington's energy policies should not provide incentives for these types of ill-conceived hydropower projects. Rather, they should actively discourage them, focusing instead on proposals that utilize existing infrastructure in an environmentally responsible manner. While we strongly advise against the use of generating capacity as a means of differentiating between different types of hydropower projects, since the term "micro" implies capacity, we can discuss maturation and market penetration in those terms. The Federal Energy Regulatory Commission has issued licenses or exemptions to licensing for 71 hydropower projects in Washington state that make up more than 7455 MW of total installed capacity. As the table below demonstrates, low capacity projects make up a significant portion of the total number of hydropower facilities in the state, suggesting that claims of market barriers are overstated. However, those projects make up an insignificant portion of total hydropower generation: doubling or even tripling the number of hydropower facilities with a capacity of 1 MW or less would not have an appreciable impact on the state's mix of energy. We note that these figures significantly inflate the total contribution of these low-capacity projects to the state's hydropower portfolio since the figures here do not include contributions from the Federal hydropower system.

Capacity (MW)	Number of Projects	Share of Total Projects	Capacity (MW)	Share of Total FERC Capacity
(all projects)	71	100%	7455.626	100%
<1	22	31%	8.139	0.11%
<5	34	48%	39.181	0.53%
<10 MW	40	56%	78.338	1.05%

B9.	Do these technologies pose potential negative environmental impacts?
Avista	Any negative environmental impacts for these technologies would be highly dependent on the location and the specific technology being used. For example, a micro-hydro project on an irrigation canal with no fish issues should have little if any environmental issues, but a project placed off a bridge or in a stream may have some issues depending on the specific location. Some technologies may also create negative impacts on recreation, aesthetics, fisheries, and habitat depending on the project design and location.
PSE	The environmental attributes of all technologies require careful assessment and a balancing of interests. All technologies have environmental impacts. Generally speaking, the environmental impacts need to be assessed in a project-

	by-project basis, rather than broadly across the technology class.
WALEA	The impacts of ocean energy technologies are not well known and currently under diligent study. Small hydro impacts are among the lowest of all technologies in terms of land use per MWh. the main concern, fish impacts, are now heavily regulated. Any small hydro system that can be permitted under the current scrutiny given these projects is likely to have minimal negative impact while generating substantial positive impact in MWh generated, often in the peak winter months.
HRC	While all energy production involves some adverse environmental impacts, hydropower is unique among non-fossil-fuel energy in the scope of its proven and significant negative impacts on river systems. Large and small hydropower dams alike disrupt flows, degrade water quality and aesthetics, block the movement of a river's vital nutrients and sediment, destroy fish and wildlife habitat, impede migration of fish and other aquatic species, and eliminate recreational opportunities. In addition, the construction of new hydropower projects requires a significant support structure and often involves building new roads in remote areas for construction and maintenance, new transmission lines, and timber cutting. The cumulative impacts of multiple low-capacity conventional hydropower projects scattered on multiple streams can be far greater than that of a single large project, while providing significantly less energy. The high financial and environmental costs of building low-capacity projects far outweigh the minimal benefits. Again, refer to our chart above: hydropower projects less than 5 MW account for nearly 40% of FERC jurisdictional dams in Washington, but provide only one half of one percent of their total capacity.

B10. 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)?	
Avista	Some level of permitting or licensing is likely required for any hydro development depending on generation capacity, technology and location. FERC already has modified rules for small hydro, so there may be some level of exemptions for small hydro already in place. There would also be requirements for state water rights and many other permits that may or may not be environmental in nature.
PSE	Micro-hydro potential is limited as a meaningful source of grid supply. However, for unique or one-off applications of a particular customer, micro-hydro might hold some potential value.
WALEA	Micro-hydro deserves a streamlined permitting path similar to what we have suggested for air quality and small biogas and biomass facilities. There are certain simplified rules that can be applied to this scale of hydro development

	that can speed the process for the vast majority of projects that have a very small impact while still giving due scrutiny to those that may have a larger impact. For run of stream projects some of those filters may be: • No impoundments of water greater than 1000 square feet • A specified percentage of flow diverted from collection structure • Intake screening • Intake above highest reach of anadromous fish • Outlet above, at, or just below highest reach of anadromous fish • Creation of artificial habitat on tailraces of projects terminating in streams containing fish species that could benefit from such habitat.
HRC	While small hydropower projects rely on the same general regulatory framework and process as utility scale projects, they are in no way treated the same as utility-scale projects. FERC provides significant flexibility in its regulatory framework, and in practice true "low impact" hydropower projects involve significantly less review. Unlike utility scale projects, if a small project (e.g. most conduit hydro projects) is genuinely unlikely to have any environmental impacts, then it can get through FERC very quickly, with minimal environmental studies or requirements. Conversely, if a low-capacity "micro" hydropower project threatens to cause real harm to other valuable public resources (e.g. the construction of a new dam on a pristine protected stream), it should be subject to strict, careful review and environmental analysis. Again, the scope of regulation for an individual project should not be based on a proposed project's potential to generate power ("utility" vs. "micro" scale) that should be considered, but rather on the scale of a project's potential environmental impacts. Existing regulatory processes have the flexibility to consider both factors. Relying solely on generating capacity to determine an appropriate level of regulation would only encourage the development of high-impact projects that are unable to contribute a meaningful amount of energy. While micro-hydro would be useful in helping meet a small part of the Northwest regional need for power, it would provide a relatively minimal amount of power at a high cost to the outstanding environmental, recreational, cultural and aesthetic values of Washington's rivers and streams. Low capacity hydropower projects also differ in that they are generally constrained by seasonal water availability, limited storage and only intermittent power generation. Often located in remote areas, and far from utility-scale transmission lines, these small projects provide no benefits to help firm other renewable energy generation, or to help integrate distributed energy into the electric grid. Due to seasonal water availability (Washington's high flows are generally late spring/early summer) and lack of storage, small and micro-hydro projects seldom provide winter peaking needs for investor-owned utilities. Equally important, this power could be easily offset by other renewable generation or by energy efficiency and conservation efforts.

Biogas

B11. What is the generation capacity and energy production potential from biogas fuels located in Washington State?	
Avista	Avista has not done any research into the amount of generation potential from biogas fuels located in Washington State. Avista's requests for proposals for renewable power in 2006, 2009 and 2011 received few bids from biogas type resources (landfill gas and wood gasification). Avista occasionally receives requests for potential PURPA type resources projects, but we have not recently signed any PURPA contracts for these types of resources.
PSE	PSE has five dairy digesters under contract with a total of2.85 MW capacity. Most of the remaining available dairy cow population in the territory resides in Whatcom County with a potential for projects of 1MW each. PSE has been working with a developer involved in converting municipal green waste to methane-gas energy via anaerobic digestion, but the project is not yet operable. Given the need for a certain level of population within a close proximity to limit transportation costs, we can envision nine such projects at 3 MW each. Problems to address include finding sites and securing green bin contracts. PSE has two wastewater treatment plants in its service territory which collect methane and produce electricity. The quantities are quite small and the cost of retrofitting a plant can be very expensive, so we do not envision growth in this area. Landfill gas is another well-known source for biogas; statewide sources would be best suited for information. Biogas from biomass, such as wood waste, has much potential on a state-wide level. The best technology would be gasification rather than anaerobic digestion.
PacifiCorp [addressing all biogas questions 11 – 14]	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 PURP A 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.
WALEA	Since almost any wet organic material can be converted in biogas, the technical potential for biogas in Washington State is enormous—in the hundreds of megawatts. However, there are and will be competing uses for wet organic material that limit the economic potential of biogas, as purchasing this fuel for

	biogas production is only feasible with high energy prices.
DNRP	In 2010, at Cedar Hills, approximately 1.4 trillion BTU of landfill gas was produced. In 2010 at South Treatment Plant, 288,440 MMBtu of digester gas was produced.
CPG	Wastewater treatment facility biogas has potential to generate over 4,000 MW of electric power within IOU service territory in Washington State.

B12. 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)?	
Avista	Avista does not have any experience with this issue. All of the biogas resources that we have studied through the IRP or RFPs for renewable resources would have received fuel from a single source, such as animal waste or landfill gas.
PSE	Fuel mixtures would be accounted for proportionately. Biogases, produced from biomass either through anaerobic digestion or gasification, are not deemed resources under the RPS; however they should be accorded the same value as landfill gas under RCW 19.285.030.
NW CEAC	Food processing waste, yard waste and spent liquors from pulp and paper mills are excluded. See cross-cutting question 4 above.
NWEC	The definition of renewable resources in I-937 includes landfill gas and gas from sewage treatment facilities; those resources are eligible to meet the renewable portfolio standard if they commenced operations after March 31, 1999, and are located in the Pacific Northwest. Biomass energy is also considered an eligible renewable resource, but municipal solid waste (and a few other sources, such as chemically treated wood) is excluded.
WALEA	The main issue with the state's renewable portfolio standard is that it defines "Nonpower attributes" to include all "avoided emissions of pollutants to the air, soil, or water, and avoided emissions of carbon dioxide and other greenhouse gases." Production of biogas often produces environmental benefits unrelated to the production of electricity; the benefits include avoided methane emissions from manure storage or landfill disposal of organic waste, improved water quality, and reduction of nutrient discharges. Most biogas projects are unable to claim credit for these benefits while also selling renewable energy that qualifies under RCW 19.285.
FPNW	The state's renewable portfolio standard has flawed definitions that make it pointless for most biogas projects to track fuel mixes with the goal of receiving credit for producing renewable electricity that qualifies under RCW 19.285. The most important flawed definition is that of "Nonpower attributes", which includes all "avoided emissions of pollutants to the air, soil, or water, and avoided emissions of carbon dioxide and other greenhouse gases." Production of biogas often also yields environmental benefits unrelated to the production

	of electricity; these benefits include avoided methane emissions from manure storage or landfill disposal of organic waste, improved water quality, and reduction of nutrient discharges. Most biogas projects are unable to claim credit for these benefits while also selling renewable energy that qualifies under RCW 19.285.

B13. 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?	
Avista	The range of project capacity sizes for biogas generation resources is directly related to the size of the gas resource being used for fuel. Most of the capacity sizes are relatively small compared to normal utility scale resources, generally in the 1 to 5 MW range.
PSE	PSE has been approached with potential projects as large as 5 MW. The constraints that limit size are the cost of transporting fuel to the site and the cost of interconnection (e.g., the need for a dedicated feeder to the substation).
WA HFC	Biodigesters are one of the few types of non-utility-scale renewable energy generation projects concentrated outside of the state's urban areas. The financial feasibility of anaerobic Biodigesters in Washington State is dependent upon the ability of digester owners/operators to obtain long-term (10 years or more) Power Purchase Agreements (PPAs) with local public utility districts (PUDs) to purchase electricity generated by the burning of biogas. However, as reported by potential Biodigester develops interviewed by the [WA HFC] and its consultants, several barriers exist. • Because these biodigester projects are typically ancillary to dairy and other farming operations, net-metering agreements (which give the power generator essentially retail value for any power being produced) are not a viable mechanism • As reported by interviewees, certain investor-owned utilities are resistant to entering into long-term PPAs, hindering developers' ability to finance digester projects • Lack of certainty surrounding (or willingness by the investor-owned utilities to negotiate regarding) the separation of the Renewable Energy Credits (RECs) from the purchase of the electricity removes another potential source of revenue that could support these projects • Biodigester developers are subject to varying policies by the IOUs and the Public Utility Districts affecting the cost of interconnection Technological advances and the development of new markets for biodigester bi-products, such as fiber and fertilizer, are bringing biodigesters closer to financial feasibility without financing subsidy. But until those benefits materialize to offset the detriment created by the low cost of power in Washington State, the continuation of tax credits, grants, and subsidized financing are important to maintaining a pipeline of biodigester projects.

	In examining financing feasibility and designing incentives related to biodigesters, it will be important to take into account the likely larger size of such projects, which will generally be larger than, e.g., solar panels on a single family home, but smaller than a utility-scale wind project. Additionally, [WA HFC] encourages continued exploration and policy support for digesters using pre- and post-consumer food waste and other fuel sources, beyond animal waste, to maximize benefits from waste to energy technologies in Washington.
NW CEAC	1. Dairy digesters generally range from 450 kW capacity to 5 MW capacity. Larger systems are possible with multi-dairies in cooperation up to 30 MW. An improved WUTC framework would enable larger systems to move forward; 2. Food processor high solids digesters can range in size from 1 to 5 MW; 3. Forest product wood waste CHP systems can range from 1 to 20 MW; 4. Pulp and paper mill wood waste CHP systems can range from 20 to 60 MW; 5. Wastewater treatment plant biogas/natural gas CHP systems can range from 1 to 10 MW; 6. Organic rankine cycle/waste heat to power generally range from 1 to 10 MW or larger depending on heat source. Nucor Steel has a proposed project of 2.5 MW but has difficulty obtaining pre-construction approval from the State Auditor due to risk for Seattle City Light's grant support; and, 7. Natural gas based CHP runs a wide range of sizes for 60 kW at Juanita High School to 738 MW at the BP Oil Refinery at Cherry Point
WALEA	Most of the technical potential is in biogas projects under one megawatt in size. Projects with the best economic potential may be larger than one megawatt, but few will exceed five megawatts in size.
FPNW	Projects with the best economic potential may be larger than one megawatt, but very few will exceed five megawatts in size. Published PURPA rates should be offered to distributed generation resources with nameplate capacities of at least two megawatts and possibly up to five megawatts.
CPG	Landfill gas plants are typically 2-20MW, depending on the age and location of the landfill. Landfill gas projects are problematic due to the life-cycle of landfills. Wastewater treatment facility (WWTF) energy projects in Washington state would fall in the 100kW - 350kW range. WWTF CHP projects are considered a 'low-hanging fruit' for DG yet there are only a handful of projects in Washington. Farm power plants would be developed in the 200kW - 1MW range and are going through pilot process (DeRueter farm, Farm Power LLC, others).

B14. 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?
Avista	Avista has not done any research into this topic.
PSE	PSE currently has no municipal green stream digester projects operating, nor under construction in its service territory. Current impediments are site control and contracting for long term fuel supply.
WALEA	These projects use a model based on European markets where energy and disposal prices are much higher than Washington State.

C. Financial Incentives:

C1. If the cost of building a distributed energy resource is not yet competitive, and a subsidy is recommended, what form of subsidy is best?	
Avista	A subsidy for distributed generation can be provided through two systemic mechanisms. One requires an interconnecting electric utility to assume costs on behalf of the generator and to recover those costs from its customers; the subsidy entails a cost-shift. A second conduit for a subsidy involves the dedication of public resources to the generator. Policies promoting distributed generation have been justified on the basis of their environmental attributes, particularly their role in reducing greenhouse gas emissions. This rationale overlooks the greater efficacy of environmental regulations which have and will continually require electric utilities that generate electricity with fossil-fuels to reduce emissions from their facilities and to acquire more efficient generation technologies over time. 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. Encouragement of distributed generation through a subsidy may not directly achieve significant environmental objectives, especially when compared to the amount of emission reductions achieved through environmental regulations. In other words, policies to advance distributed generation deployment based on environmental reasons have a societal, or "social", underpinning. Subsidies for distributed generation are, in addition, often pursued on the grounds that they will spur the creation of new jobs in the installation and manufacturing of distributed generation technologies; this objective is clearly a societal one, the costs of which should be socialized accordingly Social policy objectives should be supported with public resources. Utilities should not be used as instrumentalities for conveying a subsidy for distributed generators, especially when those subsidies necessitate that associated costs or risks must be borne by utility customers. Utility customers, as a general proposition, should not subsidize distributed generation unless the value of the subsidy is offset with a commensurate economic benefit, which is a proposition that assumes ratepayers would experience no quantifiable economic impact by

	the "subsidy". Ensuring that ratepayers would be kept financially indifferent to the existence of a subsidy may be difficult to achieve. A preferable subsidy is one that assumes the form of a government administered one that respects the prohibition in Washington State's Constitution on the lending public credit. Such a subsidy could replicate the existing investment cost recovery program; perhaps the amount of the incentive could be increased and/or the scope of the program expanded to apply to larger generators. Another subsidy could be predicated on the current sales and use tax exemptions for machinery and equipment used to generate solar energy; this exemption could be altered to encompass more distributed generation technologies. One financial incentive that would not cause a cost-shift to occur among utility customers or necessitate the deployment of public resources is one that encourages utility investment in distributed generation. One such incentive is already embodied in Initiative 937 (Chapter 19.285 RCW). As mentioned earlier, the acquisition of distributed generation or its associated renewable energy credits may be counted by a "qualifying utility" against the Initiative 937's renewable energy standards at double the value of the resource's output. This "multiplier" does not seem to encourage much, if any, acquisition of distributed generation; this would indicate that doubling the value of distributed generation for the purposes of complying with the renewable energy standards may be inadequate to compensate for the higher cost of distributed generation compared to other compliance options. We encourage the Commission to investigate this issue and identify a multiplier that would level the compliance value of distributed generation technologies with that of commercial wind resources.
PSE	The best subsidies are ones that are provided directly by the state or federal government and do not burden the shareholders nor the ratepayers of utility companies. The policies should not result in one site or one type of utility having a competitive advantage over other utilities.
PacifiCorp [addressing all financial incentives questions 1 – 3]	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.
CCWC	*Community Net-Metering* CCWC provides a mechanism for community members to subscribe to the output of a community wind turbine. Subscriptions provide us with needed upfront capital and them with green power and power bill savings for the life of the turbine. We believe incentives and policies that empower individuals to pool their resources to construct larger more efficient, well sited, and professionally managed systems are the best way to build a local energy economy. By relying on community support, distributed generation projects have natural limitations to local resource, local desire for said generation, and eliminate many forms of corporate gaming. This also ensures that the economic benefits of these systems stay local and are enjoyed broadly across our communities. Providing for Community Net Metering (also called virtual, neighborhood, or remote net metering) by our utilities would provide a market for distributed generation that was self-limiting to local demand.
WA HFC	The [WA HFC] believes that the policies and enforcement the UTC establishes for interconnection cost containment, net metering and feed-in tariffs associated with distributed energy systems materially affect their financial feasibility and thus their rate of adoption or development. Encourage the UTC's efforts to respond to the Legislature's request and call for a comprehensive review and development of State energy incentive and finance programs, taking maximum advantage of existing federal tax, loan guaranty and spending programs for distributed energy and EERE retrofits of buildings. Federal programs include: • Renewable Energy Business Investment Tax Credit • Modified Accelerated Cost Recovery System (MACRS) • Rehabilitation Tax Credits • Tax-Exempt and Tax-Advantaged Bonds (including traditional governmental and private activity bonds, as well as Qualified Energy Conservation Bonds (QECBs), and Clean Renewable Energy Bonds (CREBs) • Better Buildings Initiative • Ramp Up to Retrofit awardees (including Seattle) • Weatherization, and • FHA, DOE, USDA Rural Development and SBA loan guaranty authorities UTC and State-level financial incentives, policies, and programs which should be included in a comprehensive review and development of renewable energy

	and EERE projects include: • Cost containment of interconnection policy, practice, and costs • Feed-in tariffs • Net metering • Viable practices for development of an efficient market for RECs in WA benefiting WA RE and EERE projects • Incentives (utility, ratepayer, State) for RE and EERE projects • Review of State tax policy to remove impediments to RE and EERE projects, and to explore new tax-based incentives for such projects • Review of utility and 3rd-party PPA practices, and exploration of UTC and legislative policies to support cost efficient and feasible use of PPA contracts to support RE and EERE projects • Development and exploration of loan guaranty, utility investment, finance and support for RE and EERE projects UTC should be mindful of the potential for other developing technologies, such as waste heat recovery, that in effect are a hybrid of EE and RE projects. Many of the issues described above also affect projects such as district or neighborhood level heating or CHP strategies, which have the potential to further reduce pressure on utility-scale electricity generation by capturing and using waste heat or by feeding excess electricity generated by waste heat projects into the grid. Any incentive system must be mindful of other innovative technologies that may be currently in development or may become available in the future.
NWEC	The most efficient forms of financial incentives are either an upfront cash incentive or a performance based cash incentive paid out over time. Tax credit incentives are less efficient than cash incentives because of the costs associated with monetizing a tax credit for individuals or organizations without sufficient tax liability to fully utilize the credit (e.g., non-taxpaying entities). Furthermore, participants in either an upfront incentive (UFI) or performance-based incentive (PBI) should be explicitly allowed to assign the incentive to a third-party. The third-party installation and financing model has proven to be a highly popular and effective method for driving the development of DG due to its ability to overcome the upfront capital cost barrier, which is the main hurdle for most potential DG customer-owners. In the case of either a UFI or a PBI, such as a feed-in tariff, the incentive can be funded by ratepayers or by taxpayers.
WALEA	For standard subsidies a production-based incentive is best, it puts the obligation on the project owner to maximize output(s) of the generator. For innovation subsidies directed by a mission-oriented nonprofit can be most effective in making sure subsidies are used as wisely as possible in meeting goals not well met by set program rules. The Energy Trust of Oregon is a good example. The State Energy Program ARRA grants are another example of directed financing for innovation.
FPNW	The best subsidy for a still-uncompetitive distributed energy resource is a

	capped cash grant worth no more than 10% of the installation cost of the project. This will mimic the success of the federal "Treasury grant" in stimulating construction without as large of a cost to taxpayers and without the complication of monitoring production in future years
CPG	Equipment buy-down programs ($/kW) or production payments (based on environmental benefits) are generally best. For CHP and district energy systems, a CESOP policy or subsidization of capital project costs would help to offset the high initial costs and make projects viable. Federal grants and utility rebates can help to make up the difference in cost. If, between grants and a capital cost buy-down, there is still not an economically viable project - then the project should continue to seek the financial support it needs to become mature. We should not 'throw money' at new technologies based on our own 'opinion' of their merits.

C2. What effect would the subsidy have on encouraging the building of the resource versus research and development?	
Avista	The goal of encouraging deployment of a resource is different than an objective of promoting investment in research and development. The latter proposition seems likely to involve the offering of an incentive that would encourage the deployment of commercially unproven technologies – and, more likely than not, it would involve an assumption of costs associated with any risks that may be attendant with them. In other words, the subsidy (of whatever form) may need to be more generous than one designed to stimulate investment in commercially proven technologies, which may only require a subsidy that is adequate to buy-down the above market cost of the resource. The cost of a subsidy to promote technology research and development on utility customers and/or taxpayers may be greater than one designed to promote the use of commercialized technologies.
PSE	If the intent of the subsidy is to encourage build out, it must be first targeted at technologies that are in the pre-commercial state of development; i.e., the technology risk has been managed or minimized, but mass-market economics have not yet been realized. On this basis, the subsidy must then either enhance shareholder returns in the case of independent developer-owned projects where the competitive price of electricity would otherwise squeeze returns or must lower the cost of electricity to competitive levels in the case of utility-owned projects.
NWEC	A DG incentive program that provides either a UFI or a PBI for the installation of a DG system will be effective in promoting the installation of DG resources, but will not directly subsidize research and development. It is possible that an indirect relationship could exist between an incentive program that promotes DG installation and the encouragement of further research and development in that DG technology, although the focus of a DG incentive program should be the successful deployment of DG resources – not research and development.

WALEA	Production based incentives encourage building of the resource, directed grants are better at encouraging R&D
FPNW	At this point, Washington State needs operating projects to continue research and development—the technology must get out of the laboratory and into production.
CPG	An operation incentive such as a CESOP policy encourages the use of existing technologies in the most effective way they may be used. R&D is best encouraged by direct funding and market mechanism policies that encourage efficiency improvements for increased profits from the program. The state should not be funding R&D to any large degree.

C3. Should subsidies, incentives or renewable energy credits be paid or created for power generated through distributed resources while market prices are negative?	
Avista	No, there should not be any subsidies, incentives or renewable energy credits paid or created for power generated through distributed resources while market prices are negative.
PSE	In order for incentives to be effective they must be as certain as possible. Given that, to the extent such incentives are paid based on production, they should be paid based on actual production and regardless of market electricity prices. The disposition of subsidies and incentives depends on what the contracts have provided for. The renewable energy credits ("REC" or "RECs") as defined in RCW 19.285.030(17) are created whenever renewable power is generated. The market prices at the time a REC is generated and created is irrelevant. RECs exist independent of the market prices at the time.
NWEC	Prices on the energy spot market should not be considered as part of any DG incentive program. In order to encourage investment in DG, certainty surrounding future payments for energy produced is crucial. Furthermore, renewable energy credits (RECs) are automatically created through the tracking of power generation; disallowing REC creation would require curtailing DG systems. A DG incentive program with uncertainty surrounding future payments or possible curtailment would be highly unattractive for potential participants and businesses.
WALEA	A stable market and incentive structure is essential for growth of the industry. While distributed generation is still a small percentage of the market it should be protected from fluctuations such as negative market prices. As DG becomes established rules may need to change, but for the near future the impact of providing incentives during brief negative market periods will be negligible compared to the benefit of developing this industry. Feed in tariffs, avoided cost rates, and incentives can be structured to provide low incentive for production during periods likely to have low or negative market prices but the numbers should be preset and predictable. Oregon's avoided cost rate has an off and on peak rate, putting some of this desirability of power during certain times into the structure of their rate.

CPG	Yes. A mistruth is that distributed generation of electricity through renewable resources is contributing to negative wholesale electricity prices. We believe that utility-scale (i.e., non-distributed generation) renewable energy projects such as wind power development in rural areas are not distributed generation because they do not offset local demand. Instead they simply feed directly onto the grid in large and intermittent quantities, which directly contributes to negative electricity pricing. The distributed renewable sources designed to offset on-site use should be protected from this market phenomenon while the industry is small and investment still low. Uncertainty in return on investment would be exacerbated by the uncertainty about market prices. Financial incentives for time-of-day or peak period production are less risky.

D. Other

WA HFC	*Energy Efficiency Portfolio Standard (EEPS)* • Encourages the UTC and the Legislature to explore creating an EEPS, in which energy reductions from energy efficiency improvements would be required by a certain date, and would possibly be assisted by provisions of incentives from utilities and others to encourage building retrofits • Encourage UTC and the Legislature to explore energy efficiency standards and incentives for industrial and agricultural processes as well
PSE	*How should the impact of codes be factored in?* Disparity in the application of building codes is emerging as one of the top issues for solar installers. Each municipality can require its own set of building and electrical codes, and these disparities between requirements are emerging as a large administrative burden to the solar installer. It is also proving costly to the home owner. These fees can add upwards of $2,500 to a solar install. There is a growing call to streamline the solar permitting process to cut down on the amount of time and administration that goes into an installation.
HRC	With more than 66 percent of our energy coming from hydropower, Washington's energy system is unlike any other state in the country. Initiative 937 (I-937) was carefully crafted to provide the right incentives to promote development in new 21st century energy technologies. Increasing micro-hydro generation will do little to diversify our energy mix, and will divert valuable public resources away from the development of innovative new renewable technologies. Under I-937, hydropower is considered a renewable resource, and the initiative provides incentives for efficiency upgrades to enhance hydropower generation at existing dams, for adding generation at nonpower dams (e.g. storage and flood control) and for new hydrokinetic projects. The Washington Department of Ecology's 2010 Inventory of Dams lists regulation of more than 1100 dams already in existence, and the 2007 Washington State Resource Assessment Report lists more than 250 existing dams in Washington that either do not have hydropower or are not operating at peak efficiency. The report shows that more than 2,500 MW could be added simply by improving

	efficiencies or adding hydro to non-power dams. The report also demonstrates that developing all the state's potential hydro sites would only add 762 MW, a figure that greatly overstates the amount of potential capacity by failing to consider feasibility. Doubling the number of hydropower projects in the state with 10 MW or less of capacity would add only 150 MW of new capacity. Given the number of existing dams in Washington State, policies encouraging new dam construction ("micro" or not) should not be contemplated until the entire potential of the State's existing hydropower infrastructure has been exhausted.
DNRP	*Are additional incentives needed?* *Sewage-based energy* I-937 has left some question whether sewage-based energy will qualify as "renewable" in Washington State. Energy captured from sewage in conveyance lines, before it reaches a treatment plant, should clearly be defined as "renewable" in state legislation. *District Energy* While neighborhood-scale energy generators may be interested in developing district energy systems, they will also need to incentivize end users (real estate developers) to convert to the system. Many district energy technologies rely on hydronic building heating and air conditioning systems - radiators, in-floor radiant heat, or forced air with a backup boiler system for peak use. Incentives for capital-intensive hydronic systems (rather than electric baseboard systems) would not only buy down the cost of connecting to a district energy system but also preserve future distributed energy potential. Interestingly, older or historic buildings with existing boilers and water radiators become good candidates for district energy retrofitting. *Sewage Energy Demonstration Projects* 1. Maintaining sewage heat/organic material content as a WTD asset: With a demonstration period that allows developers access to sewage for district energy projects, WTD can incentivize District Energy innovations while gathering information on the value of heat energy as a product. This window also allows the project piloting the technology a "start-up" period for testing the technology before establishing the value of the heat energy. 2. Supporting WTD's Primary Mission and Asset Integrity: Any connection to the County's sewer main that allows the drawing of fuel (heat, organic material, flow) from the wastewater conveyance must not impact WTD flow or reliability. The County's operation of its wastewater system shall have priority, and the County may require the temporary suspension of the heat energy recovery operation as necessary to ensure reliable performance of the wastewater system. 3. Determining the Level of Certainty Required to Incentivize Capital Investments: Developers will need a reasonable length of agreement and some sense of a future rate model to assess their capital risk. Based on the information gained during the demonstration period, the County will

	develop a rate model for heat energy. 4. How It Gets Built - Developer Builds, Permits, Operates and Maintains: The developer will construct the connection to WTD's conveyance system in conformance with the County design standards at its sole expense and be responsible for obtaining all permits and regulatory approvals for the design, installation and operation of the District Energy Project. 5. Required Data Gathering for Demonstration Period: The developer will keep records of various ongoing data points for the project and will make those records available to County for the life of the connection to WTD's system. Such data points include, but are not limited to, the amount of sewage diverted, amount of heat extracted from sewage, and detailed operating costs of heat exchanger system. 6. Ownership of Potential Renewable Energy Credits (RECs): A portion of any REC proceeds received by the developer for the project should be shared with the County.
Seattle Steam Company (Seattle Steam)	*Combined Heat and Power and Waste Energy Recycling (CHP and WER)* [See Comments of Seattle Steam at 1-2 for a list of benefits from CHP and WER systems] Actions/policies to enable optimal deployment of CHP/WER and other local generation: 1. Change decision process on all capacity to compare the delivered cost of power from each source. Local generation has strong economic advantages over remote generation due to line loss and T&D capital avoidance, but is then compared as though all delivery costs were equal 2. Include WER as fully eligible for clean energy portfolio standards, equal to wind or solar 3. Give fueled CHP a credit for RPS equal to 60% of the MWh of useful thermal energy recycled, which is equivalent to the fuel savings of a MWh of fuel free power 4. Require purchasing utilities to calculate the line loss savings and to offer at least 85% of the value of those line loss savings to distributed generation 5. Require utilities to offer 85% of the value for power factor support (PFS) and voltage support (VS) from distributed generation, in return for the generation owner giving the grid manager control over power factor and voltage from the local generation 6. Recognize the value of local generation with PFS and VS in freeing transmission lines to carry remote wind power 7. Seek to price transmission at a more granular level, as opposed to the BPA practice of assuming a 2% line loss, regardless of source or use point. This will sharpen the economic signal for where distributed resources have maximum value 8. Set a goal of making CHP/WER profitable for the utility, the host, the developer, and the public. This probably involves having the utility purchase the power and keeping the retail customer. It may involve

	allowing the utility to earn a bonus for improving generation and distribution efficiency or reducing the need for capital in new transmission and distribution lines. It requires standardized and transaction light processes for long term contracts for WER/CHP power. Conventional RFP procurement done at the utility timetable do not facilitate WER/CHP development. 9. In the absence of items 1 – 8, likely because of the inability of utilities and regulators to easily unbundle the value of these sophisticated components of power generation and transmission, for projects that provide the features discussed herein, power factor support, voltage support, high efficiency load center energy generation and the virtual ability to store energy as discussed above, create a special power purchase agreement at a set cost per kWh generated that will ensure such projects are financially sound. This special power purchase may form part of the regional supply of electricity rather than one specific utility in whose region this capability geographically exists