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Executive Director and Secretary
Washington Utilities and Transportation Commission
1300 South Evergreen Park Drive SW
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Cascade Power Group applauds the Washington State Legislature and the Washington State Utilities and Transportation Commission for embarking on this journey to determine the merits of distributed energy and applicability for Washington State. From a philosophical perspective, we believe that “energy delivery systems” should be separated out from “energy fuels” and that any policies or incentives should be reflective of such. It makes no sense to send clean, renewable electricity through a system that loses up to 20% of that resource by the time it gets to final destination. Similarly, it makes no sense for a biomass plant to be built in a rural area and to not utilize the waste heat from the plant.

Combined heat and power and district energy systems are an efficient energy delivery system. Whichever fuel is fed into the system will be used efficiently. This represents a sound approach to energy resource planning, and counters the imperialistic notion of ‘harnessing resources’ and sending them to where people need them.

Other groups are presenting the options for distributed wind, solar, and biogas - and so our comments will largely focus on combined heat and power, district energy, and waste heat recovery projects for the state. We look forward to assisting the State with this endeavor, and are available at any time for comments or clarification to our position and opinions.

Sincerely,

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A. General – Cross-Cutting Issues:

1. What is the scope of current and anticipated distributed energy in the service territories of Washington's investor-owned utilities, including technology type, size and capacity; distribution across service territory; application of feed-in tariffs or netmetering; 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?

CHP/District Energy resource assessment for the PNW

a. 2004 U.S. Dept of Energy CHP technical potential study for Pacific Northwest http://www.chpcenternw.org/NwChpDocs/Chp_Market-Assessment_In_PNW_EEA_07_2004.pdf
b. 2010 WSU Energy Program CHP technical potential study http://www.chpcenternw.org/NwChpDocs/WA%20CHP%20Technical%20Potential%2008%202010.pdf
c. 2004 U.S. Dept of Energy "Denny Triangle" district energy study http://www.chpcenternw.org/NwChpDocs/EnergyDistrictForSouthLakeUnionAndDennyTriangle.Phase1FeasibilityStudyFinal.pdf

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. 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. While distributed generation resources should be streamlined for public investment, energy-efficiency technologies are also crucial elements of an updated energy supply strategy for Washington.

The on-site technical potential of CHP in Washington State is calculated as being well over 4,000MW by WSU Energy Program's "Northwest Clean Energy Application Center" in a 2010 study[1]. Most of this potential is found in the petroleum refining, food processing, primary metals, wood products and paper products industries. This also includes 235MW of waste heat potential.

Another study funded by the U.S. Department of Energy in 2004 found a potential offset of 123MW if a district energy system is built in the "Denny Triangle" area of downtown Seattle.[2]

[1]Northwest Clean Energy Application Center. (Aug, 2010). State of Washington Clean Energy Opportunity: Technical Market Potential for CHP. *U.S. Department of Energy.*

[2]FVB Energy Inc. (Feb, 2004). Energy District for South Lake Union/Denny Triangle: Phase 1 Feasibility Study Final Report. *Washington State University Energy Program.*

That is a huge energy savings for such a small area. These examples are all MW's that exist now and with the correct application of policy incentives we can capture them.

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

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.

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

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.

- For electricity produced using solar modules manufactured in Washington state: 2.4
- For electricity produced using a solar or wind generator equipped with an inverter manufactured in Washington state: 1.2
- For electricity produced using an anaerobic digester, by other solar equipment, or using a wind generator equipped with blades manufactured in Washington state: 1.0
- For all other electricity produced by wind: 0.8

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 there is an equipment buy-down program for emerging technologies.

We have recently suggested to the Legislature that a new type of community-investment tool could help to combine the avoided cost benefits of distributed generation with the climate benefits of clean-tech. Under a 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.

Important Benefits of CESOP:

1. Induces profitable greenhouse-gas emission reductions.
2. Stimulates private-sector investments in cleaner, cheaper thermal and electric energy.
3. Provides cost-reduction benefits to all stakeholders, including the distribution utilities, manufacturers, and all retail customers.
4. Improves U.S. manufacturing competitiveness and preserves and adds industrial jobs.

4. Are there changes in state statutes or rules that would encourage technology-neutral development of distributed energy generally, such as changes to financial incentives? For example,

- **Would current interconnection standards need to be changed to accommodate more distributed energy or to accommodate different distributed energy technologies? Why?**

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. Investors need to know that they will at least break even and that the policies supporting these technologies are consistent. 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 CO_2 and gain energy improvements locally.

Best Practices in Interconnection Procedures:

- 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, particularly where
- Standardize and simplify forms.

Recommendations for WA:

- Prohibit requirements for redundant external disconnect switch
- Prohibit requirements for additional insurance

http://www.newenergychoices.org/uploads/FreeingTheGrid2010.pdf

Organizational/social: government and regulating authority(s)

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

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 such as

- American Electric Power Co, Inc and other utility companies in the PJM Interconnect are moving forward with energy storage projects between 2MW and 20MW
- Hawaii (island of Oahu) is also doing battery storage projects as a way of mitigating voltage drop while solar irradiance conditions are intermittent
- California is working on large battery projects in Los Angeles and other So. California locations, and have made energy storage a functional part of their RPS standards
- Minnesota is integrating battery storage with wind power production

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

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 (ie, grid-pairty). 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.

The US Department of Energy produced an excellent paper for FERC in 2007, regarding the impacts of distributed generation on rates and ratepayers: http://www.ferc.gov/legal/fed-sta/exp-study.pdf

Main findings of this paper were:

- Few utility companies are currently using distributed energy resources for the purpose of providing benefits to electric system planning and operations.
- Economics of and knowledge of distributed energy projects are case-by-case and very site-specific. Project economics for utility-owned distributed energy is difficult and is reflected by a lack of existing utility-owned DE projects.
- Distributed energy systems offer benefits to planning and operations of utility companies (peak load reduction, power quality, etc)
- Distributed energy systems reduce vulnerability from terrorist attack or grid-failure
- Distributed energy systems have beneficial effects on land use and needs for rights-of-way for electric transmission and distribution
- Regulation for distributed energy deployment widely varies by state and utility service territory, making generic deployment more difficult across a multi-state or regional jurisdiction

7. 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?

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.

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

If a state has a renewable requirement under PURPA authority (I don'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" [2]. 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.
More here: http://financere.nrel.gov/finance/content/ferc-ruling-changes-course-and-assists-renewables

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

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 (ie, significant emissions avoidance costs). Joseph Iannucci provided an excellent white paper on behalf of NREL in 2003 that defines the various "benefits" of distributed energy systems, and should be used as a framework for defining these benefits. Here is a link to the paper, it is a MUST read for anyone studying distributed generation integration: http://www.nrel.gov/docs/fy03osti/34636.pdf

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

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.

Here is a 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

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

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.

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

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.

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:

Input Values	Offset Values
Biomass $4.00 /MMBH	Electricity $21.97 /MMBH
Natural Gas $0.70 /Therm	Heating $8.75 /MMBH
Grid Electricity $0.075 /kWh	Cooling $3.75 /MMBH
NG Boiler Efficiency 80 %	NG CHP Costs
Elec Chiller Efficiency 0.60 kW/Ton	Fuel $0.069 /kWh
NG Generator Efficiency 34.5 % HHV	Maintenance $0.020 /kWh

http://www.maceac.psu.edu/workshops/042811Presentations/Foley-Module%205%20-%20CHP%20Economics%20-%20PA.pdf
Simply get the point across that in most cases CHP produces energy and economic savings.

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

http://www.chpcenternw.org/NwChpDocs/Thekdi%20presentation.pdf (from 2007)
Technology is improving and payback is generally said to be about 2-3 years.

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

Protection costs should be born 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 (ie, dual protection and relays).

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

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 (ie, 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.

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

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.

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

The US Department of Energy has identified up to 240GW of combined heat and power projects throughout the nation that can be achieved by the year 2020 under existing market conditions, and would bring the total generation mix from CHP sources from 8% (2008) up to 20%.

The 2009 McKinsey report "Unlocking Energy Efficiency in the US Economy" has identified CHP as a way to save the nation $7.9B each year in energy costs and offset 1.4 quadrillion BTUs of energy consumption. It is represented as a "negative-cost" energy efficiency measure (meaning the climate and efficiency benefits outweigh the upfront capital cost of implementation). CHP is declared a "proven" and "low-cost" energy efficiency measure in the report, and considered "commercially viable" by the US Department of Energy.

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:

Biogas

11. What is the generation capacity and energy production potential from biogas fuels located in Washington State?

Wastewater treatment facility biogas has potential to generate over 4,000 MW of electric power within IOU service territory in Washington State.
http://www.cascadepowergroup.com/upload/BW%20Feasibility%20Final%20Draft.pdf

13. What is the range of project capacity sizes for biogas generation resources and how does that compare to the capacity sizes for projects that qualify for published PURPA rates?

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)

C. Financial Incentives:

1. If the cost of building a distributed energy resource is not yet competitive, and a subsidy is recommended, what form of subsidy is best?

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.

2. What effect would the subsidy have on encouraging the building of the resource versus research and development?

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.

3. Should subsidies, incentives or renewable energy credits be paid or created for power generated through distributed resources while market prices are negative?

Yes. A mistruth is that distributed generation of electricity through renewable resources is contributing to negative wholesale electricity prices. We believe that utility-scale (ie, 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.