Distributed Generation in Oregon: Overview, Regulatory Barriers and Recommendations

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February 2005

Public Utility Commission
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INTRODUCTION AND EXECUTIVE SUMMARY

The Oregon Public Utility Commission established in 2002 an objective to identify and remove regulatory barriers to the development of distributed generation. Staff began at that time a comprehensive review of uses and benefits, status and potential in Oregon, regulatory barriers to further development, and recommendations for removing barriers. This report presents staff's findings and recommendations.

Among the three Commission objectives for 2005-06 is to adopt regulatory policies that encourage utilities and customers to meet energy needs at the lowest possible cost and risk. Removing regulatory barriers to the use of distributed generation is one way the Commission plans to meet this objective.

Distributed generation produces electricity at or near the place where it's used. Technologies include:

- *Combined heat and power (CHP, or cogeneration) systems* that produce both electrical and thermal energy and use the heat or steam for industrial processes, heating or cooling. Systems can run on fossil fuel, biomass or waste heat and can be designed to use more than one fuel. Among the technologies are internal combustion engines, combustion and steam-cycle turbines, microturbines, fuel cells, Stirling engines and gasification digesters.
- *Systems that use renewable energy resources* to generate electricity without making use of any waste heat, such as solar electric systems, wind turbines, small hydroelectric generators, and turbines or internal combustion engines using landfill gas
- *Reciprocating engine generators and small combustion turbines that run on diesel or natural gas*, typically used for backup power or for power in remote locations

Many of these technologies can be more energy-efficient and cleaner than central-station power plants. Their smaller size can better match gradual increases in utility loads. Distributed generation also can reduce demand during peak hours, when power costs are highest and the grid is most congested. If located in constrained areas, distributed generation can reduce the need for distribution and transmission system upgrades. Adding small generators to the grid also can increase reliability. Customers can install generation to cap their electricity costs, sell power, participate in demand response programs, provide backup power for critical loads and supply premium power to sensitive loads.

Some 500 MW of distributed generation systems operate in Oregon today. The additional economic potential for the state is estimated at 384 MW by 2025, without taking into account incentives or reduction in technology costs. In a scenario with incentives, reduced costs and other favorable conditions, an estimated 1,831 MW in additional systems could be installed in the next 20 years.

Among the regulatory barriers to development of distributed generation:

- The state does not have uniform technical standards, procedures or agreements that allow for quick, inexpensive and simple interconnection of small generators with utility systems, where appropriate.
- Rates for backup power may not properly reflect actual costs.[1]
- Some PURPA policies in Oregon may be outdated and need refinement.

[1] In Order No. 04-400, the Commission adopted the parties' Stipulation and approved new PGE tariffs for backup power. Unless otherwise noted, staff's comments about backup power in this report do not apply to PGE's tariffs, which staff continues to support.

- Customers can’t easily sell power from on-site generation to the utility through a competitive bidding process, to a marketer or to other customers directly.
- Utility planning for energy and capacity needs is done in isolation from distribution and transmission system planning, and neither generally considers distributed generation.
- The utilities' revenues are based on how much power they sell and move over their wires, and they lose sales when customers develop generation on site. Utilities also do not earn a return on non-utility resources or make profits on them through operational efficiencies.

Staff recommends the following actions to remove these barriers:

1. The Commission should implement uniform technical standards, procedures and agreements for interconnecting generators.

2. The Commission should adopt in PacifiCorp’s rate case (UE 170) standby tariffs that properly reflect the costs and benefits of serving customers with distributed generation.

3. Through UM 1129, the Commission should extend the contract length for Qualifying Facilities, increase the size eligible for standard purchase rates, establish Commission-approved standard purchase agreements for facilities eligible for standard rates, and review methods for valuing avoided costs when a utility is resource-sufficient. To mitigate risk to ratepayers of long-term, must-take contracts, the Commission should allow fixed pricing under standard PURPA rates and contracts only for small Qualifying Facilities.[2]

4. The Legislature should add biomass as a qualifying resource for net metering and allow the Commission to increase the eligible project size for Portland General Electric (PGE) and PacifiCorp.

5. The Commission should explore issues related to customer-generators selling power to other retail customers over the distribution system.

6. The Commission should investigate how to include distributed generation in utility planning and acquisition processes to meet energy, capacity, distribution and transmission system needs at the lowest cost.

7. The Commission should explore mechanisms for removing disincentives for utilities to facilitate cost-effective distributed generation at customer sites.

8. The Commission should consider approval of a utility's request for accounting treatment that would allow a return on its capital investments in customer-owned distributed generation, similar to that previously approved for investments in conservation.

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[2]Fixed pricing is the approved cost of the avoided resource, set throughout the term of the contract and based on a single set of forecasted prices. Parties disagree on what size Qualifying Facility should be eligible for fixed pricing.

USES, BENEFITS, STATUS AND POTENTIAL

Unlike central station power plants, which typically are located far from load centers, distributed generation produces electricity at or near the place where it's used. Distributed generation technologies can run on fossil fuels, renewable energy resources or waste heat. Equipment ranges in size from less than a kilowatt (kW) to tens or, in some cases, hundreds of megawatts (MW).

Distributed generation can meet all or part of a customer's power needs. If connected to the distribution or transmission system, power can be sold to the utility or a third party. Some technologies also provide heat or steam for use at or near the site. Customers, utilities and independent power producers can develop and operate distributed generation systems. They can be located at a customer's site or otherwise near customer loads.

Technologies[3] include:

- *Combined heat and power (CHP, or cogeneration) systems* that produce both electrical and thermal energy and use the heat or steam for industrial processes, heating or cooling. Systems can run on fossil fuel, biomass or waste heat and can be designed to use more than one fuel. Among the technologies are internal combustion engines, combustion and steam-cycle turbines, microturbines, fuel cells, Stirling engines and gasification digesters.
- *Systems that use renewable energy resources* to generate electricity without making use of any waste heat, such as solar electric systems, wind turbines, small hydroelectric generators, and turbines or internal combustion engines using landfill gas
- *Reciprocating engine generators and small combustion turbines that run on diesel or natural gas*, typically used for backup power or for power in remote locations

New and improved technologies and higher power prices are putting these systems within the reach of more consumers. The U.S. Energy Information Administration estimates that 19.1 gigawatts of new distributed generation capacity will be added by 2020, accounting for some 5 percent of capacity additions.[4]

Uses

Distributed generation can be used in a variety of ways:

- *In remote locations* where it may be more economic than running a power line to the site. Distributed generation may be cost-effective for serving small loads in lieu of even short line extensions.
- *To provide primary power*, with the utility providing backup and supplemental power. Systems may be sized to sell power in excess of site needs.
- *For backup power* during utility system outages, for facilities requiring uninterrupted service — hospitals, military facilities and prisons, for example — as well as businesses with high costs for forced outages, such as data centers, banks, and the telecommunications and process industries.
- *For cogeneration*, where waste heat can be used for heating, cooling, dehumidifying, or steam. Traditional uses include large industrial facilities with high steam and power demands, including paper and chemicals industries, as well as universities and hospitals.

[3]Appendix A explains how these systems work.
[4]Robert T. Eynon, U.S. Department of Energy, "The Role of Distributed Generation in U.S. Energy Markets," http://www.eia.doe.gov/oiaf/speeches/dist_generation.html.

- *To provide higher power quality* for electronic and other sensitive equipment.
- *During times of high electricity prices or high on-site demand*. Customers that pay time-varying prices or participate in other peak-shaving programs can use distributed generation during high-cost periods and reduce their overall cost of power. The electricity supplier in turn may be able to reduce the amount of high cost power it purchases during system peaks.
- *To reduce air emissions* at a site, by using a renewable energy source or cleaner energy system.
- *To defer or avoid transmission and distribution system investments*.
- *To provide energy or capacity to the utility*.
- *To provide ancillary services* — reliability services that allow the system to produce and deliver energy in a usable form, for example, at the proper voltage and frequency:[5]
  - Reactive supply and voltage control from generation - Injecting and absorbing reactive power to control grid voltage
  - Network stability - Using fast-response equipment to maintain a secure transmission system
  - System blackstart – Capability to start generation and restore a portion of the utility system to service without outside support after a system collapse
  - Regulation - Maintaining generation/load balance minute-to-minute
  - Load following - Maintaining generation/load balance hour-to-hour
  - Spinning reserves - Immediate (10-second) response to contingencies and frequency deviations
  - Supplemental reserves - Restoring generation/load balance within 10 minutes of a generation or transmission contingency
  - Backup supply - Restoring system contingency services within 30 minutes if the customer's primary supply is disabled

Benefits

Following are benefits, or potential benefits, of distributed generation for customers and utilities. Some of the benefits depend on project-specific characteristics, including technology, fuel source, emission controls, operating patterns, customer load shape and load-shedding capability, and characteristics of the network where the generation is connected. Policies to advance distributed generation should take into account how to achieve desired benefits.

Efficient use of resources - The average efficiency of the existing fleet of fossil-fuel power plants in the U.S. is 33 percent. That means they waste two-thirds of the fuel's energy value before it reaches customers, mostly as heat. CHP systems capture the waste heat produced during generation for use in industrial processes, heating or cooling (using absorption chilling technology).

U.S. EPA states that CHP systems are over 50 percent more efficient than the separate production of electricity and thermal energy such systems displace, assuming utility plant efficiency of 31 percent (similar to the national average) and industrial plant boiler efficiency of 80 percent.[6]

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[5]Rick Weston, *Accommodating Distributed Resources in Wholesale Markets*, Regulatory Assistance Project, September 2001.
[6]Luis Troche, EPA CHP Partnership, *Combined Heat and Power: An Energy-Efficient Choice for the Ethanol Industry*, Final Draft, January 2005.

The newest natural gas-fired, combined-cycle combustion turbines (CCCTs) have an efficiency of about 50 percent. [7] Still, CHP systems have an efficiency of at least 60 percent, and the most efficient CHP systems are 80 percent efficient or better. [8] Further, economics drive customer and third-party investors in CHP to maximize efficiency and minimize cost by sizing the project to match thermal load, often recovering 100 percent of available waste heat.

Because CHP systems usually are much more energy-efficient than producing heat and power separately, they optimize use of natural gas and other fuels.[9] Reducing natural gas usage helps keep down natural gas prices, which are highly correlated with power market prices.

Reduced environmental impact – Some types of distributed generation, including those that run on renewable resources or waste heat as well as CHP systems using state-of-the-art emission controls, produce power with less environmental impact than conventional generation. The environmental benefits of such CHP systems are especially attractive if they replace old boilers with dated air emission controls. An additional environmental benefit of these systems is reduced carbon dioxide emissions compared to separate production of electricity and useful thermal energy. Distributed generation also can provide an economic incentive for mitigating environmental problems — for example, processing manure in digesters to capture waste methane for electricity production.

Reduced grid costs - Distributed generation can cut utility costs by delaying, reducing or eliminating the need for investments in distribution and transmission facilities, if generators are located where the grid is constrained. (In some locations, distributed generation could increase network costs.) The Northwest Power and Conservation Council's Regional Technical Forum uses a default value of $20/kW-yr for the avoided costs of deferring or reducing these investments. PacifiCorp's filings in Oregon show avoided costs of $57.59/kW-yr for its distribution system and $21.40/kW-yr for its transmission system. PGE estimated avoided costs at $15.40/kW-yr for its distribution system and $7.18/kW-yr for its transmission system.[10] The actual benefit of distributed resources in deferring grid investments is site-specific and depends on their ability to reliably serve peak loads on congested transformers, feeders and lines.

Reduced investment risk - Smaller, more modular units require less project capital and less lead-time than large power plants. That reduces a variety of risks to utilities, including forecasting of load/resource balance and fuel prices, technological obsolescence and regulatory risk. Power plant additions typically overshoot demand, leaving substantial amounts of capacity idle until demand catches up. Smaller units can better match gradual increases in demand.

Peak shaving – To the extent that distributed generation operates reliably during standard peak periods, severe weather events and high market prices, it reduces demand on the utility system when power costs are highest and the grid is most congested. Customers can use their

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[7]Based on a heat rate of 6,863 Btu/hr for "G" class CCCT technology. (Heat rate from PGE's Final Action Plan/2002 Integrated Resource Plan, March 2004.)
[8]U.S. Department of Energy Distributed Energy Program Web site: http://www.eere.energy.gov/de/technologies/euii_chp_tech_basics.shtml.org.
[9]One study found that increasing CHP capacity by 50 percent in the regions studied (California, Texas and the Northeast) could reduce natural gas consumption by an average of 6.4 percent. (Energy and Environmental Analysis, Inc., "Natural Gas Impacts of Increased CHP," prepared for the U.S. Combined Heat and Power Association, October 2003.)
[10]Regional Technical Forum, ***Recommendations to the Bonneville Power Administration Regarding Conservation and Renewable Resources Eligible for the Conservation and Renewable Resources Rate Discount and Related Matters***, Sept. 1, 2000. Values represent the "probability weighted avoided cost" of distribution or transmission system upgrades, reflecting that not all savings occur in a part of the system that is nearing its capacity limit.

generators to participate in demand response programs. And utilities can make use of distributed generation to keep their costs down during the highest load hours of the year.

Improved reliability and power quality – Reliability is the measure of whether electricity is available to users. It includes two elements: 1) adequacy — sufficient power supply to satisfy demand at all times and 2) security — the ability to withstand unplanned outages of the electric grid caused by events such as tree contact or failure of grid elements due to equipment malfunction or human error. Power quality — the shape of power waveforms — is the suitability of electricity for servicing loads.

Power outages and power quality problems can cause severe financial losses for businesses through process disruptions, losses in finished products, equipment damage, lost productivity and failure to meet customer needs. Distributed generation can provide the very high reliability and power quality that some businesses need, particularly when combined with energy storage and power quality technologies.

Distributed generation provides reliability benefits for the utility system by adding generating capacity; freeing up the utility's own generating resources or contracted supplies; freeing up distribution system capacity; reducing congestion on the transmission system, improving the reliability of supply into the service area; and providing backup power to support utility maintenance and restoration operations.[11]

Further, a large number of *small* units is more reliable than a small number of *large* units. That's because a failure of any one unit has far less impact. Small units do not require a large block of potentially costly replacement power, and they tend to be faster to fix. Distributed resources further increase reliability by reducing the distance the power must travel and the number of grid components that could fail along the way.

Other benefits:[12]

- Distributed energy resources, in tandem with smart grid technology, make energy systems more secure from attack.[13]
- Generating power where it's needed reduces losses over distribution and transmission lines.
- Small generators, especially at existing business facilities, are easier to site than large power plants. Generating power close to the point of consumption also reduces the need to site new transmission and distribution lines.
- Generators at or near customer loads may be located at the least-used parts of the utility's electric grid — and those with the highest losses and costliest requirements for reactive power.
- Small generating equipment can more readily be resold or moved to a better location.
- On-site generation can cap a customer's power costs, providing the certainty businesses need.
- Sale of power is a potential profit center for businesses.
- Increasing the number of suppliers selling energy and capacity increases competition and stems market power. Further, distributed generation in transmission-constrained areas may

[11]Arthur D. Little, Inc., *Reliability and Distributed Generation*, 2000.
[12]For an exhaustive catalog of benefits, see Amory B. Lovins, E. Kyle Datta, Thomas Feiler, Karl R. Rabago, Joel N. Swisher, André Lehmann and Ken Wicker, *Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size*, Rocky Mountain Institute, 2002.
[13]Wade Malcolm, vice president of Power Delivery and Markets, Electric Power Research Institute, presentation to National Association of Regulatory Utility Commissioners, Feb. 14, 2005.

mitigate the exercise of market power and increase the efficiency of wholesale power markets.
- Customer or third-party investments in distributed generation reduce required utility investments in energy and capacity resources.
- In summer peaking areas, solar electric systems provide the most energy during the highest cost (peak load) hours.
- Distributed generation can reduce reactive power consumption and improve voltage stability of the distribution system at lower cost than voltage-regulating equipment.

Status and Potential

Distributed generation projects in Oregon range from long-standing cogeneration plants at paper and wood products mills as well as recent installations of microturbines and fuel cells at commercial and institutional facilities. (See Table 1, attachment to this report.) Several hundred small renewable energy systems serve Oregon homes and businesses. Altogether, about 500 MW of distributed generation systems operate here today.

In addition, Oregon utilities contract with a number of small hydroelectric (and other) facilities in accordance with federal PURPA law. See Appendix B for PURPA projects selling to investor-owned utilities in the state.

Following are status and potential by type of distributed generation:

Combined Heat and Power Systems

Boiler-steam turbine cogeneration systems have been used for many years by Oregon industry to provide both power and steam for industrial processes. They can run on waste heat, natural gas, hogged fuel, sawdust, spent pulping liquor, waste methane gas or oil.

More recently, gas turbine generators with exhaust heat recovery have been installed at several sites to provide power and steam for industrial processes. Reciprocating engine-generator sets with waste heat recovery are used at energy facilities using waste biogas and at industrial cogeneration projects that use natural gas.

There are about 30 CHP systems in use in Oregon, totaling more than 400 MW of electric generation capacity.[14] Natural gas turbines comprise most of these projects. The others use fuels from renewable sources including wood residue, dairy waste and spent pulping liquor. Wastewater gas fuels nine systems.

A few of the largest facilities sell electricity to utilities or the wholesale market. Some facilities operate only seasonally or are idle due to high fuel prices or plant closures.

Two high-efficiency cogeneration facilities have received an exemption from state siting requirements, but have not yet been built: at the Pope and Talbot Paper Mill in Halsey (proposed project is 93 MW) and West Linn Paper Company (proposed project is 41.7 MW).[15]

[14] Not including central-station power plants, such as the Coyote Springs, Klamath and Hermiston projects, which provide steam to nearby industries. *See* Energy and Environmental Analysis, Inc., "Combined Heat and Power in the Pacific Northwest: Market Assessment – Final Report," Report No. B-REP-04-5427-004r, prepared for Oak Ridge National Laboratory, August 2004, Table A-4.

[15] Oregon law requires a site certificate from the state Energy Facility Siting Council before non-renewable energy facilities 25 MW or larger can be built. The threshold for renewable energy projects is higher. Cogeneration facilities that meet efficiency standards, standby generation and certain expansions may apply for an exemption from this requirement.

Small CHP systems such as microturbines, fuel cells, small conventional gas turbines and new-generation reciprocating engines are best suited for customers with substantial thermal needs, such as process industries, hospitals, prisons, health clubs and laundries. Other markets are data centers that need high power reliability, computer chip manufacturers that need high-quality electricity, resource recovery (waste gas at landfills and wastewater treatment plants), and applications where energy is needed far from powerlines. Fuel cell markets include homes and commercial and institutional buildings.

Cost. Some CHP technologies are cost-effective today, depending on size, fuel and thermal host. Others still are far too costly compared with alternative power and heat sources. Table 2 shows estimates in 2003 by the National Renewable Energy Laboratory of energy costs for a variety of natural gas-fired CHP technologies, using U.S. Energy Information Administration projections of natural gas prices. Table 3 shows the Laboratory's estimated capital and non-fuel operation and maintenance costs. More recently, the Northwest Power and Conservation Council estimated the costs of cogeneration installed in 2010, using the Council's medium-case natural gas price forecasts. (Table 4)

Table 2. Levelized Energy Costs for Natural Gas-Fired CHP Technologies[16]
(¢/kWh – 2003$)

Technology	Capacity	2005	2010	2020
Reciprocating engines	100 kW	6.3	5.8	5.6
	300 kW	5.7	5.7	5.4
	1 MW	5.1	5.0	5.1
	3 MW	5.1	5.0	5.1
	5 MW	4.8	4.8	4.8
Gas turbines	5 MW	5.3	5.1	5.1
	10 MW	4.9	5.0	5.0
	25 MW	4.4	4.5	4.4
	40 MW	4.1	4.2	4.3
Microturbines	30 kW	9.4	8.6	7.5
	70 kW	8.3	7.6	6.7
	100 kW	7.9	6.9	6.1
	200 kW	8.0	7.4	5.6
	500 kW	nc	6.7	5.7
Fuel cells - Proton exchange membrane	10 kW	18.6	13.8	9.6
	200 kW	13.3	10.1	7.6
Fuel cells – Molten carbonate	250 kW	17.3	11.5	9.3
	2 MW	13.0	9.7	7.5
Fuel cells – Solid oxide	100 kW	13.0	9.6	8.1
Small steam turbines (back-pressure)	500 kW	nc	4.4	4.6
	3 MW	nc	3.2	3.5
	15 MW	nc	3.1	3.3

*nc – Not characterized

[16]Larry Goldstein, Bruce Hedman, Dave Knowles, Steven I. Freedman, Richard Woods and Tom Schweizer, *Gas-Fired Distributed Energy Resource Technology Characterization*, National Renewable Energy Laboratory, NREL/TP-620-34783, November 2003. The analysis uses U.S. Energy Information Administration projections for natural gas prices delivered to industrial users, as described in the *Annual Energy Outlook 2003*. Availability of technologies and prices in 2005 not validated.

Table 3. Capital and Non-Fuel O&M Costs for Natural Gas-Fired CHP Systems[17]

Technology	Capacity	Installed Cost (2003$/kW)	O&M Costs (2003$/kWh)
Reciprocating engines	1 MW	$940	$0.009
Gas turbines	5 MW	$1,024	$0.006
	10 MW	$928	$0.006
	25 MW	$800	$0.005
	40 MW	$702	$0.004
Microturbines	30 kW	$2,262	$0.02
	100 kW	$1,769	$0.015
Fuel Cells - Proton exchange	200-250 kW	$3,800*	$0.023*
Molten carbonate	250 kW	$5,000*	$0.032*
Solid oxide	100-250 kW	$3,620*	$0.024*
Small steam turbine (back-pressure)	3 MW	$385	NA

*In 2005.

Table 4. Estimated Cost of Cogeneration in the Northwest – 2010 In-Service Date (2000$)[18]

Technology/ application	**Unit size** (MW)	**Capital** ($/kW)	**Fixed O&M** ($/kW/yr)	**Variable O&M** ($/MWh)	**Fuel**	**Fuel price/ escalation**[19] ($/MMBtu)/ (%/yr)	**Heat rate** (Btu/kWh) (base/CHP)	**Benchmark power cost** ($/MWh)[20]
Gas turbine generator for pulp and paper mill process steam	48	$860	$65	$5.00	Natural gas (Council's industrial forecast)	$4.70/0%	9,550/5,280	$47
Forest residue steam-electric plant	25	$2,000	$80	$9.00	Forest thinning residue	$1.00/0%	14,500/4,500	$52[21]
Reciprocating engine for hospital water heating	0.5	$2,220	$9	$12.50	Natural gas (Council's commercial forecast)	$7.25/0%	9,350/4,920	$73
Gas turbine generator for institutional space conditioning	8.5	$2,420	$150	$7.15	Natural gas (Council's commercial forecast)	$7.25/0%	13,300/6,000	$94
Microturbine for office building hot water and space conditioning	0.1	$1,490	Included in variable O&M cost	$15.00	Natural gas (Council's commercial forecast)	$7.25/0%	13,130/7,300	$127

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17 *Ibid*.
18 Jeff King, Northwest Power and Conservation Council, January 2005.
19 Forecast 2010 price in year 2000 dollars; average annual escalation from 2010 to 2025. To convert from 2000 prices to 2005 prices, multiply by 1.11, an estimate of inflation between 2000 and 2005.
20 Benchmark cost assumptions: Levelized lifecycle cost, 2010 in-service date, no incentives to offset project costs, uniform financing (20 percent consumer-owned utility, 40 percent investor-owned utility, and 40 percent independent financing), a 90 percent capacity factor, the Council's medium-case natural gas price forecast (where applicable), and the Council's forecast of future technology costs. Except for microturbine, cost is delivered to the local grid, including a $2/MWh ancillary service charge. Microturbine assumes load displacement; no ancillary service charge. CO_2 penalty, as applicable, set at the mean of the portfolio analysis for the Council's Fifth Power Plan. Cogeneration costs are based on fuel-charged-to-power heat rate. Power costs do *not* include a 6% transmission loss credit for generation located at load.
21 Power costs are higher than for a natural gas-fired CHP facility due largely to higher capital costs.

NW Natural[22] estimates the installed cost today of a 30 kW microturbine at $3,000 per kW, with operation and maintenance costs (including fuel) at $1,800 per year. For projects meeting efficiency standards, the payback is about 8-1/2 years after a state tax credit.[23] Larger projects, with their improved economies of scale, have quicker paybacks. For example, a 1 MW reciprocating engine has a 5-1/2 year payback after tax credits. To maximize return on the customer's investment, NW Natural recommends sizing small CHP systems to the customer's thermal and electrical requirements. In other words, the customer should use on-site all the electricity and heat that the system produces all the time.

Table 5 summarizes cost and performance characteristics for small cogeneration systems that run on waste steam, rather than fossil or biomass fuels. The costs shown are the incremental costs for the power generating equipment; the boiler and steam system are assumed to be necessary for process steam whether or not a generating system is installed.

Cost-effectiveness of these distributed generation systems can be assessed by comparing cost estimates in Tables 4 and 5 to the Council's price forecast for the Mid-C trading hub — $34.40 per megawatt-hour (2000$), levelized over 20 years beginning 2010.[24] Based on this analysis, back-pressure steam turbines, steam turbines using waste process steam and, likely, large cogeneration plants[25] are cost-effective for industrial facilities compared to buying power from the utility.[26] Depending on actual fuel and power prices and reductions in technology costs, other types of distributed generation may become cost-effective during the plan's timeframe (through 2024).

Table 5. Representative Small Steam-Electric Cogeneration Plants (2000$)[27]

Type of facility	0.5 MW chemical plant back-pressure cogeneration[28]	3 MW pulp and paper back-pressure cogeneration	15 MW pulp and paper back-pressure cogeneration	6.8 MW industrial waste heat recovery cogeneration[29]
Electrical efficiency (Btu/kWh)	4,520	4,570	4,390	N/A[30]
Capital cost ($/kW)	$870	$360	$330	$1,440
O&M ($/MWh)	$3.80	$3.80	$3.80	$5.30
Benchmark power cost ($/MWh)[31]	$33.20	$27.40	$26.30	$22.40

[22] Chris Gelati, NW Natural, February 2005.
[23] See Appendix C for information on Oregon incentives for distributed generation. Past funding from the Energy Trust of Oregon for a microturbine project reduced the payback to about six years.
[24] Jeff King, February 2005.
[25] After adding retail delivery and other utility charges; not including incentives.
[26] Under federal PURPA law, utilities must purchase at their avoided costs the electricity offered from cogeneration facilities that meet efficiency standards (as well as certain renewable resources 80 MW or smaller). Utilities also can negotiate economic purchases from cogeneration facilities outside of PURPA based on the actual costs of the utility's other resource alternatives.
[27] Except for benchmark power cost, data for back-pressure projects are from Energy and Environmental Analysis, Inc., *Technology Characterization: Steam Turbines*, prepared for U.S. EPA, March 2002. For comparison to Table 4, costs were converted to 2000$ by Jeff King, Northwest Power and Conservation Council.
[28] Figures for back-pressure systems assume that steam pressure will be raised to accommodate the back-pressure turbine, requiring additional fuel. In some cases, however, a back-pressure turbine can substitute for an existing throttle and eliminate the requirement for additional fuel.
[29] Capital and O&M costs from John Martin, Pacific Energy Systems, Inc.
[30] No fuel costs; system uses only waste heat.

Potential. A recent report prepared for Oak Ridge National Laboratory estimates CHP technical and economic potential for the Pacific Northwest.[32] Tables 6 and 7 show findings for Oregon. To determine estimates of *technical* potential, researchers: 1) identified applications where CHP systems fit reasonably with the electric and thermal needs of the user, based on energy consumption data by type of facility; 2) quantified the number and size distribution of applications that meet the thermal and electric load requirements for CHP systems; 3) estimated the potential CHP capacity for these applications; and 4) subtracted existing CHP systems from the identified sites to determine the remaining technical potential. Researchers also estimated future regional growth to determine the potential for CHP at new industrial and commercial sites.

Researchers defined *economic* potential as the estimated market acceptance level for the share of the market with an economic payback of less than 10 years, based on the weighted average technology mix. They considered two cases:

- The "Business as Usual" case assumes no near-term improvement in technology, no incentives for CHP (for Oregon, they assumed discontinuation of current incentives), and standby charges of $4/kW/month for systems up to 20 MW and $3/kW/month for systems 20 MW or larger. This case also assumes that lack of awareness of CHP and the poor economic climate for developers limit market penetration, especially for smaller systems. Under these conditions, the additional economic potential for Oregon is estimated at 384 MW by 2025.
- The "Accelerated" case assumes CHP technology improves considerably, incentives are available to offset 15 percent of initial capital cost, and standby charges are eliminated. This case further assumes greater developer activity, in part because education programs increase awareness about CHP. In this scenario, an estimated 1,831 MW in additional systems could be installed in the next 20 years.

For another perspective on economic potential, NW Natural estimates some 1,300 CHP projects totaling about 800 MW are economic today in its Oregon service territory at current state incentive levels.[33]

So who are the likely customers for CHP (and other distributed generation) systems? The Oak Ridge study found that the greatest *technical* potential in Oregon for applications at existing large industrial facilities is in the paper and food industries, followed by the wood products and chemical industries. The wood products industry accounts for most of the potential at large industrial facilities for exporting electricity beyond site needs. For small industrial applications, defined as 5 MW and less, researchers found the greatest potential is with the food industry (those with year-round production). Among commercial and institutional applications of all sizes, the researchers found that office buildings hold the greatest promise, followed by colleges and universities, hotels and motels, K-12 schools, apartment buildings, restaurants, and hospitals and health care centers.[34]

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[31]Calculated by Jeff King, Northwest Power and Conservation Council, February 2005, using the same assumptions as in Table 4, except for the 6.8 MW industrial heat recovery project which has no fuel costs.
[32]Energy and Environmental Analysis, Inc., August 2004. Technical potential does not account for economic factors such as rate of return, ability to retrofit, capital availability, natural gas availability, and avoided electricity and fuel costs.
[33]Analysis by Chris Gelati, NW Natural, April 2004.
[34]*Ibid*, Tables 4-1, 4-9 and 4-11.

Table 6. Technical Potential of Combined Heat and Power Systems in Oregon for Existing and New Facilities[35]

Type of application	Capacity (MW)
Existing Facilities	
Large Industrial* – On Site	356
Large Industrial – Export**	753
Resource Recovery***	11
Small Industrial	547
Commercial	1,796
New Facilities (2002-2022)	
Large Industrial – On Site	66
Small Industrial	246
Commercial	1,288
Total Technical Potential	**5,063**

*Systems larger than 5 MW.
**Excess capacity above the site electrical demand.
***Biomass fuels, such as wood and paper waste, and methane gas from sewage treatment plants and animal feedlots.

Table 7. Economic Potential of Combined Heat and Power Systems in Oregon by 2025[36]

	Economic Potential - Business as Usual	Economic Potential - Accelerated Case
System Size	*Total Additional Capacity*	
50-500 kW	6 MW	212 MW
500-1,000 kW	36 MW	417 MW
1-5 MW	23 MW	320 MW
5-20 MW	120 MW	524 MW
20-50 MW	147 MW	233 MW
>50 MW	53 MW	124 MW
Total	**384 MW**	**1,831 MW**

Another study, conducted by Primen in 2003, found that 13 percent of U.S. and Canadian customers in the 100 kW to 10 MW size range are prospects for distributed generation.[37] The top three drivers are energy cost savings, improved power reliability and predictable energy prices. Concerns about distributed generation among this customer group include service

[35]Energy and Environmental Analysis, Inc., August 2004, Table 4-17.
[36]*Ibid,* Table 5-13. The analysis uses the Northwest Power and Conservation Council's medium-case natural gas price forecast (delivered prices) and Wholesale Electricity Price Forecast for the Draft Fifth Power Plan (April 21, 2004, draft).
[37]Primen, *Distributed Energy Market Study 2003*, summarized in PacifiCorp's presentation at the Jan. 29, 2004, Integrated Resource Plan public input meeting. Primen conducted the study prior to the August 2003 blackout. The study found that 11 percent of energy users in this size range are "soft" prospects — they say the likelihood of acquiring baseload distributed generation in the next two years exceeds 50 percent, but they have not begun to actively evaluate their options. Another 2 percent are "strong" prospects — they state the same likelihood of acquiring distributed generation *and* they are actively evaluating their options.

warranties and service agreements, environmental permitting, and rising and volatile natural gas prices.

According to this study, the best candidates for distributed generation are companies that are expanding or relocating facilities and companies that are replacing aging boilers, chillers, heating systems or generators. Market conditions, blackouts and other electric service failures also create short-lived moments of opportunity for closing deals.

An earlier study by Primen found that the strongest prospects for distributed generation are customers 700 kW or larger. Prospects who were actively evaluating distributed generation options cited gas engines (29 percent), gas turbines (29 percent) and microturbines (21 percent) as the technologies they are most likely to acquire. Most of those likely to acquire these technologies already have standby generators and would be willing to dispatch them during peak demand if given the right incentives.[38]

According to Primen, the most promising market applications in the near term are waste gas markets, including oil and gas operations, wastewater treatment plants and landfills; cogeneration systems, particularly those with built-in heating and cooling equipment so custom engineering isn't required; and pre-engineered packages of generation and storage systems that provide highly reliable power.[39]

Demonstration Projects. The Northwest CHP Consortium is helping fund CHP systems in Oregon to demonstrate the reliability of technology designed for smaller applications and to get enough projects built so customers can more readily see and replicate them. The group includes representatives of NW Natural, PGE, PacifiCorp, Bonneville Power Administration, the Oregon Department of Energy, U.S. Department of Energy, the city of Portland, American Gas Association, Gas Technology Institute, Energy Solutions Center, and the distributed generation industry.

The consortium's first project was at the 200 Market Street building in downtown Portland. The high-efficiency 30 kW natural gas microturbine provides emergency and night lighting in a 300,000 square foot office complex. The waste heat is used to preheat return water for the primary boiler and seasonally to generate chilled water with a heat-activated absorption chiller. The chiller supplements cooling needs for equipment during summer months when simple economizer cooling won't suffice. PGE, PacifiCorp and BPA tested the system to ensure it met their interconnection specifications and IEEE standards, so they don't have to perform these tests each time a customer installs this system.

Two additional projects have been installed: A 30 kW microturbine at the Lewis and Clark campus generates electricity, heats a swimming pool and, in the summer, provides domestic hot water to keep a large boiler off-line. A 5 kW fuel cell provides electricity and hot water at Harkins House in Hillsboro, a juvenile detention facility. For each project, costs, performance and other statistics are posted on Bonneville's Web site, along with Autocad drawings and virtual tours of the generating facility. The consortium hopes to install another 10 MW to 15 MW of systems ranging in size from 5 kW to 500 kW.

[38]Primen, *Research Highlights: Releasing the Potential of Distributed Energy*, 2002. Based on 600 interviews in June-July 2002 with North American businesses ranging in size from 300 kW to 10 MW.
[39]"Microturbine Markets Revisited," *Primen Perspective*, Issue 9, December 2001.

Bonneville Power Administration has worked with Northwest utilities and Bend, Ore., manufacturer IdaTech to demonstrate home-sized fuel cell systems. The initial systems run on methanol. One of them, a refrigerator-sized 5 kW unit at PGE's Earth Advantage Center, is interconnected to the grid. Bonneville also is demonstrating the ability to control and monitor a microturbine system delivering grid-connected power in a commercial building to evaluate whether and to what extent this approach is a reliable and quantifiable non-wires solution to meet transmission needs in some cases.

The city of Portland has operated a 200 kW fuel cell at its Columbia Boulevard wastewater treatment plant for several years. Instead of flaring off all of the waste methane gas, some of the fuel is generating electricity and heat for sewage treatment. The U.S. Department of Defense and the Oregon Department of Energy supported the project. The city recently installed four 30 kW microturbines at the facility.

Biomass Systems

Biomass fuels are from plants and other organic matter. They include materials from fields and forests, mill residues, spent pulping liquor, food processing waste, landfill gas, and the organic component of municipal solid waste. Distributed generation technologies for these fuels can provide electricity alone or electricity plus useful steam or heat.

In addition to the CHP biomass applications described earlier, three landfills in the state tap waste methane gas to generate 4 MW of electricity and provide industrial fuel.[40]

The Northwest Power and Conservation Council estimates the cost to generate electricity from wood waste in the Northwest at 5.4¢ to 6.5¢ per kWh (for cogeneration applications). The Council estimates the cost of producing power from anaerobic digestion of manure at 5.6¢ per kWh, and from landfill gas energy recovery at 4.5¢ per kWh.[41]

The Council estimates technical potential for generation in the Northwest as follows: 1,000 aMW to 1,700 aMW from wood residue; 100 aMW to 200 aMW from landfill gas; and 50 aMW from manure.[42]

A recent assessment of potential power and fuel production from forest and agricultural resources in Wallowa, Union and Baker counties estimated the availability of these resources at 736,000 tons per year. A 25 MW biomass power plant would need some 430,000 tons of material per year.[43]

PGE recently built a 100 kW digester at Cal-Gon Farms in Polk County to produce electricity from the manure of some 400 cows. Two of four planned manure digester units at the Port of Tillamook Bay recently began operation. Each unit has a capacity of 400,000 gallons and a 200 kW engine/generator set. The State Energy Loan Program is financing the project. The Oregon Department of Energy also has approved a loan for a 1.06 MW digester at a Rickreal dairy with some 3,500 cattle. The project will use waste from local food processing plants, as well as

[40]Source: Oregon Department of Energy.
[41]Draft Fifth Power Plan, Sept. 22, 2004, Table 5-2; 2000 dollars, 2010 in-service date. The Northwest Power and Conservation Council generally does not consider landfill gas applications as distributed generation.
[42]An average megawatt (aMW) is 8,760 megawatt-hours — the continuous output of a resource with a capacity of 1 MW over a year.
[43]McNeil Technologies, Inc., *Biomass Resource Assessment and Utilization Options for Three Counties in Eastern Oregon*, prepared for the Oregon Department of Energy, December 2003. The levelized cost of energy from those plants, including the costs of delivering the fuel, is estimated at about 14¢ to 15¢ per kWh.

manure. An independent developer will build, own and operate the facility and has plans for several more digester installations. The department also has financed a 230 kW project at a Carlton, Ore., dairy. A 4 MW manure digester system at a 21,000-cow dairy near Boardman is under consideration, as well.

Small Solar, Wind and Hydroelectric Systems

By year-end 2003, Oregon had some 318 solar electric systems for home use and 35 systems for businesses. The size ranges from a few hundred watts to several kilowatts on homes to 114 kW at the Kettle Foods plant in Salem and 172 kW on three buildings owned by Pepsi Cola Bottling of Klamath Falls. Residents and businesses have installed 45 small wind systems. Small hydro systems serve 20 homes. Businesses have installed 25 hydroelectric systems, some of which are serving energy needs at or near customer sites.[44]

Costs for small renewable energy systems are declining but remain high. A 3 kW home solar electric system connected to the grid costs about $20,000, with levelized costs estimated at 60¢ to 70¢ per kWh. State and federal incentives reduce those costs significantly, to about 14¢ per kWh for businesses and 25¢ per kWh for residents.[45]

Though large wind facilities are cost-effective today with federal incentives in portions of the state, small-scale applications are still high-priced. A 10 kW wind system that's connected to the electric grid, for example, costs at least $35,000 installed, with levelized costs of about 23¢ per kWh. Larger turbines cost less per kW installed — for example, $100,000 for a 50 kW system.[46] Operation and maintenance costs are about 1.5¢ per kWh.[47]

Seasonal micro-hydro systems can be installed at irrigation piping canals. Run-of-the-river hydroelectric technology also can be tapped.

Dispatchable Customer Standby Generation

Backup generating systems at customer sites typically operate only during utility outages. But these resources, which most commonly run on diesel, can be used to help meet electric system needs.

PGE, for example, relies on dispatchable standby generation to help meet its capacity requirements. The company has 17 MW of dispatchable customer standby generation in place today, some 26 MW under contract, and plans for 30 MW in place by winter 2006-07.

The program is available to customers with generators 1 MW and larger that agree to allow the company to use them up to 400 hours per year. Participants include high technology, medical and telecommunications industries. The utility reconfigures the grid connection to make the generator dispatchable, maintains the unit and pays for all fuel. If PGE needs peak capacity resources, it requests operation of the generators, then starts and monitors their performance. The unit supplies the customer's facility first. Any excess capacity is sent to the grid. If the utility system has an outage while the generator is in parallel operation, the connecting breaker trips and the generator continues to supply the customer.

[44] Oregon Department of Energy data are available through 2003. Most renewable energy systems in the state receive tax credits through the department's programs. Many of the wind systems were installed in the 1980s and no longer are operating.

[45] Oregon Department of Energy estimates. The Energy Trust of Oregon estimates installed costs for small solar systems at $6.35 to $6.50 per watt. Larger systems cost less per watt. (Peter West, Energy Trust, June 2004.)

[46] Carel DeWinkel, Oregon Department of Energy, June 2004. Levelized costs assume a real discount rate of 3 percent and equipment life of 15 years.

[47] Paul Gipe, *Wind Energy Comes of Age*, John Wiley and Sons, 1995.

Bonneville Power Administration is testing dispatchable standby generation for another purpose — as an alternative to building new transmission lines in the Northwest. BPA is conducting a pilot program on the Olympic Peninsula in Washington state to determine whether the agency can aggregate and manage backup generating resources at customer sites in order to reduce peak demand on the transmission system.

Energy Storage

Another distributed energy resource, energy storage, is an important counterpart to distributed generation. Energy storage technologies can firm and shape wind and solar resources as well as support fossil-fuel power plants to meet demand during peak periods. Technologies can store electrical or thermal energy.

PacifiCorp recently installed the first vanadium-based, battery energy storage system in the U.S. It will defer for at least four years a 69 kV line and new substation in Castle Valley, Utah. Savings are estimated at $3.4 million (net present value). The system will be used to improve reliability for customers located at the end of the utility's longest distribution line.

The system converts electrical energy into chemical potential energy by charging two liquid electrolyte solutions stored in adjacent tanks. Electrical energy (250 kW) is stored during off-peak times, then distributed during the eight peak hours. The system provides voltage support 24/7 regardless of the charging/discharging state of the unit.[48,49]

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[48]PacifiCorp news release, "Utah Power cuts ribbon at pilot battery storage project," March 25, 2004.
[49]Randy Rhodes, “Non-wires Alternatives: Transmission and Distribution,” presentation to Oregon Public Utility Commission, Dec. 16, 2004.

REGULATORY BARRIERS

Some types of distributed generation are more expensive today than utility-supplied power. As costs for distributed generation decline, other barriers could continue to hinder its advancement. Following are what PUC staff sees as the main *regulatory* barriers that the Commission should address. Potential regulatory barriers outside of the Commission's reach, related to siting and air quality permitting, are covered briefly at the end of this section. Appendix D lists barriers identified by large customers, the utilities and the distributed generation industry. Among them are up-front capital costs, nascent technology, and electricity generation not being a core activity for most businesses.

A. The state does not have uniform technical standards, procedures or agreements that allow for quick, inexpensive and simple interconnection of small generators with utility systems, where appropriate.[50]

Today, each Oregon utility has its own standards for ensuring that interconnected generators are compatible with the electric grid for safety, reliability and other purposes. Each utility also has its own policies, procedures and contract terms for interconnection. While large facilities may require customized engineering and legal work, unnecessarily stringent standards, procedures and agreements for small systems result in undue delay and expense and may make projects uneconomical.

Technical standards
Many of the standards that utilities adopt for their equipment and systems come from the Institute of Electrical and Electronics Engineers (IEEE) and American National Standards Institute. Utilities are involved in the development of these standards, which helps ensure they meet their needs. Once a utility adopts a standard, equipment certified to meet the standard typically is acceptable. Utilities are not required to adopt the standards, though a number of utility commissions and states specify that the technical interconnection requirements for distributed generation be based on the standards adopted by IEEE as well as the National Electrical Code.[51]

Standards include specifications related to power quality, dispatch, safety, reliability, metering, and distribution system operation and control, such as:
- Power flow studies and other engineering and feasibility analyses
- Requirements for protective relays and transfer switches
- Power quality requirements for voltage and frequency disturbances, voltage fluctuation and waveform distortion
- Operating limits
- Tests and inspections

In 2003, the IEEE approved technical standards (Standard 1547) for interconnecting distributed resources 10 MW and less, with specific requirements related to performance, operation, safety

[50] For more information on interconnection barriers, see R. Brent Alderfer, M. Monika Eldridge and Thomas J. Starrs, *Making Connections: Case Studies of Interconnection Barriers and Their Impact on Distributed Power Projects*, National Renewable Energy Laboratory, NREL/SR-200-28053, May 2000.
[51] The Oregon Public Utility Commission enforces the National Electrical Code as well as the National Electrical Safety Code and would take both into account in adopting technical standards for distributed generation.

and maintenance.[52] The standards are designed to allow potential generators and utilities to quickly agree on equipment and hookup protocols. IEEE is currently developing testing standards and guides for compliance, monitoring and information exchange related to distributed generation.

One principal safety concern related to distributed generation is "islanding," where a generator continues to supply power to the grid when the utility's power supply to the local grid has been cut off. In such cases, an independent generator operating in parallel to the grid could feed a short circuit, potentially causing a fire, and utility personnel could contact a line they thought was de-energized. Further, electrical equipment might be damaged by abnormal electrical conditions typical in such "islands." Most small generating technologies, including microturbines, fuel cells, solar panels and wind turbines, have built-in protective features to prevent islanding.

Many small generators can be installed without extensive engineering studies, additional hardware or testing because they already incorporate technology to address safety, reliability and power quality concerns. California, New York and Texas have a precertification process in place for such systems. The experience of these states provides evidence that uniform technical standards are needed to identify and expedite the process for facilities that don't require an engineering study and are considered safe to connect to the grid.

Uniform technical standards limit opportunities for utilities to favor their own generation and help ensure fair interconnection charges for generators. Further, allowing manufacturers to produce to common standards promotes efficient equipment markets, and uniform standards reduce confusion among developers and safety personnel.

Procedures and agreements
Each Oregon utility has its own procedures and contract terms for interconnection. If they impose delays, costs or requirements that are unnecessary for purposes of safety and reliability, they may needlessly discourage distributed generation.

Procedures for interconnection approval may be unnecessarily complicated for some small projects, timelines for conducting engineering studies and processing applications may not be specified, utility responses are not always timely, and approval times may be long. Further, interconnection contracts are lengthy and complex, and some terms and conditions may not be appropriate for small generators. Application and study fees also may not be matched to the size of the system.

In addition, PGE, PacifiCorp and Idaho Power require in their interconnection agreements (other than for net metering) that the customer maintain liability insurance for the generating facility.[53]

NARUC model standards
NARUC first published in 2002 model procedures and applications for interconnecting generators of various sizes, as well as a standard interconnection agreement, based on best state practices.[54] The model was intended to serve as a catalyst and framework for state

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[52]Institute of Electrical and Electronics Engineers, *Standard 1547: IEEE Standard for Interconnecting Distributed Resources With Electric Power Systems*, July 28, 2003.
[53]The state's net metering law prohibits utilities from imposing such requirements for solar, wind, hydro and fuel cell systems 25 kW or less. See ORS 757.300(4)(c).
[54]National Association of Regulatory Utility Commissioners, *Model Distributed Generation Interconnection Procedures and Agreement*, July 2002.

proceedings on interconnection standards. It left many technical and policy issues to each state's discretion, including size limits, precertification standards, time frames, fees and dispute resolution.

In 2003, NARUC published a revised document aimed at small generators that further addresses these issues.[55] The NARUC model includes a "super-expedited" process for installations that will have low impacts on the utility system. To qualify, the system must meet screening criteria that, for example, take into account the type of technology and distribution circuit, the capacity of all generation on the circuit, and the contribution of all generation on the circuit to its maximum fault current and short circuit interrupting capability.

Detailed study procedures are for systems that do not meet these criteria. The procedures provide for a feasibility study, system impact study, a facility study and determination of company construction as required. These procedures resemble those currently in use by many utilities to qualify all interconnection requests, but are standardized and apply only to more complex systems.

Federal standards

Generators over 20 MW. The Federal Energy Regulatory Commission (FERC) in 2003 established interconnection standards, procedures and agreements for generators over 20 MW.[56] FERC largely reaffirmed its position on rehearing.[57]

The final rule required public utilities that own, operate or control facilities for transmitting electricity in interstate commerce to file revised open access transmission tariffs (OATTs) containing compliant interconnection procedures and a standard interconnection agreement.[58]

The requirements apply to interconnection with transmission facilities already subject to an OATT on file with the Commission at the time the generator submits an interconnection request. The facilities must be used to transmit electricity in interstate commerce or to sell electricity at wholesale in interstate commerce under an OATT on file with FERC. FERC further asserts that "dual use" distribution facilities, those used for both wholesale and retail transactions, are subject to its rule if they are included in the OATT on file with FERC at the time of the interconnection request.[59]

Generators 20 MW and smaller. FERC is now considering standards for interconnection of generators 20 MW and smaller where it has jurisdiction.[60] The proposed rule includes standard procedures and a standard agreement to be used by a public utility to interconnect small generators with a public utility's transmission facilities, as well as with FERC-jurisdictional distribution facilities if the generator will be selling electricity at wholesale in interstate commerce.

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[55] National Association of Regulatory Utility Commissioners, October 2003.

[56] FERC Order No. 2003, Standardization of Generator Interconnection Agreements and Procedures, issued July 24, 2003. 68 FR 49,845 (Aug. 19, 2003), FERC Stats. & Regs. ¶31,146 (2003).

[57] Order No. 2003-A, issued March 5, 2004, and Order No. 2003-B, issued Dec. 20, 2004.

[58] The requirements also apply to other utilities that seek voluntary compliance with the reciprocity conditions of public utility transmission tariffs.

[59] Grace Delos Reyes, National Association of Regulatory Utility Commissioners, Summary of the Order on Rehearing on Standardization of Generator Interconnection Agreements and Procedures (Docket No. RM02-1-001; Order No. 2003-A). NARUC maintains that states have jurisdiction over all interconnections to the distribution system other than those for interstate commerce.

[60] Docket No. RM02-12-000, Standardization of Small Generator Interconnection Agreements and Procedures, July 24, 2003.

The proposed standard interconnection agreement addresses cost responsibility, establishes milestones for the completion of the interconnection, and lays out a process for dispute resolution. Proposed interconnection procedures lay out the process for evaluating the interconnection request and include:

- *A standard interconnection request form*

- *"Super-expedited" procedures for interconnecting facilities no larger than 2 MW to a low-voltage transmission system (less than 69 kilovolts)*, *if a national testing laboratory certifies that the system meets consensus industry standards for safe operation.*[61] The purpose of precertification is to ensure the safety of the generating system only (for example, the generator does not energize a circuit unless grid voltage is present), not the safety or reliability of the proposed interconnection to the utility system. Therefore, the precertified system must meet criteria that qualify it as having no adverse impact on the utility system. For example, the installation must meet thresholds for load and short circuit contributions. If the installation meets these criteria, the generator is entitled to a presumption of approval without additional studies or testing.

  If the proposed installation fails the super-expedited screening criteria, the utility could permit the interconnection after evaluating factors such as its location on the utility system. Or the customer could ask the utility to perform, at the customer's expense, a limited and expedited engineering evaluation to identify minor changes that may permit safe and reliable interconnection. If the evaluation does not find that the facility can be interconnected safely and reliably with only minor changes, the parties would follow the "expedited" procedures outlined below.

- *"Expedited" procedures for interconnecting facilities larger than 2 MW, but no larger than 10 MW, to a low-voltage transmission system.* If the proposed interconnection passes the expedited screening criteria and the utility believes the facility can be interconnected safely, the utility offers the customer the standard interconnection agreement. If, however, the utility believes the facility cannot be interconnected safely because it may cause an adverse system impact due to its proposed location on the utility system, regardless of whether the proposed interconnection passes the expedited screening criteria, the utility would decide after further review with the customer whether to proceed with a scoping meeting and interconnection studies (as described in the next tier of procedures). In order to encourage use of the expedited procedures, the utility, rather than the customer, must pay for the feasibility study if no adverse system impact is identified.

- *Procedures for interconnecting facilities 20 MW and less to a high-voltage transmission system (69 kilovolts and above).* Once the utility deems the interconnection request is complete, the utility and the customer would conduct a scoping meeting to review the interconnection request and relevant studies of the utility system. Next, a feasibility study, system impact study, and facilities study would be performed to evaluate the proposed interconnection. These studies identify any adverse impact to the utility's system that may occur as a result of the interconnection, and utility system modifications needed to mitigate the impact. The customer pays for the actual cost of the studies, and the utility must abide by set timelines for completing the studies. (The proposed timelines are shorter than those required under FERC requirements for interconnecting large generators.)

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[61]IEEE 1547 could serve as the basis for a national precertification standard.

- *Procedures for interconnecting facilities larger than 10 MW to a low-voltage transmission system.* The procedures are the same as those for facilities interconnecting to a high-voltage transmission system.

Once these steps are completed, the utility would provide the customer a best estimate of costs for any required utility system modifications, and the parties would negotiate milestones for completing the interconnection. FERC's proposed rule assigns the cost of distribution system upgrades directly to the interconnecting customer; the cost of transmission system upgrades is assigned in the same manner as is specified in the large generator interconnection final rule, which allows the customer to receive credits against future transmission services for upfront construction payments.

FERC is seeking comment on its proposed insurance requirements. Among the questions are whether requirements should differ depending on facility size and technology, and whether certain of the smallest generators should be exempt from insurance requirements.

B. Rates for backup power may not properly reflect actual costs.[62]

Customers with on-site generation may not produce enough electricity to serve their entire load. Generators also are shut down periodically for planned maintenance, and they occasionally have unscheduled outages. In addition, customers may shut down their generators to buy power from the utility (or an alternative supplier) when it costs less than running them.

Utilities provide standby service[63] (also called partial requirements service) to:
1. Supply the supplemental power customers need when their generators are operating
2. Supply the backup power customers need when their generators are not running (during a planned or unplanned outage)
3. Maintain the generation and grid capacity to deliver these services

Substantial locked-in payments to the utility through standby tariffs can override the benefits of distributed generation to the customer. A 2000 report by the National Renewable Energy Laboratory cited excessive standby tariffs as the greatest regulatory barrier to distributed generation.[64] They also were among the most frequently cited barriers in PUC staff's discussions with large Oregon electricity customers.

Standby tariffs may set a customer's demand *level* for an entire year based on an assumed maximum load on the utility system when the generator is off-line, or the actual demand that occurs during a single outage of the customer's generator — even if it's during off-peak hours when there's surplus grid capacity. In other words, a customer that normally supplies all its electricity needs on its own may be charged for the same demand level as a same-size customer that gets all its electricity from the utility.

The standby demand *rate* may be the same as in the full requirements tariff, or it may be a reduced rate. There also may be penalty rates for exceeding the demand specified in the customer's contract.

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[62]See footnote 1.
[63]Standby service is for customers that use on-site generation on a regular basis, not those with generators used only during utility outages.
[64]R. Brent Alderfer, *et al*.

FERC rules to implement the federal Public Utility Regulatory Policies Act (PURPA)[65] require that rates for supplemental and backup power be just, reasonable and in the public interest, and not discriminate against Qualifying Facilities in comparison to rates for other customers.[66] The rules further prohibit a utility from basing standby rates on the assumption (unless supported by factual data) that these facilities will impose demands at the same time as one another, or during the system peak, or both.[67]

Cost-based standby rates

Standby tariffs should be based on the actual costs of providing backup generation and grid capacity for distributed generators during their occasional outages, spread across the year and following random patterns. At the same time, an outage during off-peak periods does not impose the same cost on the utility system as an outage during times of highest demand. In the future, when more distributed generation is developed, the class profile of customer-generators could serve as the cost basis for providing backup delivery service. With so few customer-generators on the system today, however, the utilities use the general customer class (customers with a demand of 1 MW or more) as the cost basis for delivery service.

Standby rates also should reflect the benefits of distributed generation when it reduces congestion on transmission lines and frees up capacity at distribution substations and subtransmission facilities. However, distribution facilities closer to the customer's site are not sufficiently shared to provide much benefit from any capacity that may be freed up.

To reflect these costs and potential benefits in rates, utilities should offer both firm and interruptible standby service. Rates should be fully unbundled, including a discrete item for generation reserves required by the Western Electricity Coordinating Council (WECC).

There should be no inherent incentive for standby customers to idle their generators when natural gas and wholesale power prices are high. Customers that have reliable control equipment to reduce loads instantly when their generator trips off-line or reduces output should not have to pay for utility distribution and transmission facilities, or reserves charges, based simply on the nameplate capacity of the generator.

Interruptible service should enable a customer to buy backup power on a short-term basis, optimizing the economic operation of the generator. Energy rates for the interruptible option should be market-based.

Standby charges should not apply to customers with generating systems less than 1 MW. Variations in demand resulting from such small systems going off-line at different times are not noticeable to the utility system.

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[65]Code of Federal Regulations (CFR), Title 18-Conservation of Power and Water Resources, Part 292-Regulations Under Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 with Regard to Small Power Production.
[66]18 CFR §292.305(a)(1).
[67]18 CFR §292.305(c)(1).

Standby rates in Oregon

PacifiCorp. PacifiCorp provides standby service to 13 Oregon customers.[68] Schedule 36 applies to customers with a demand less than 1,000 kW; Schedule 47 applies to customers with a demand 1,000 kW and greater.

Standby customers can choose any of the energy options that other nonresidential customers have: standard cost-of-service, an alternative energy supplier, or daily market pricing based on prices at the Mid-Columbia (mid-C) trading hub.

The company's standby charge is 50 percent of the standard demand charge (for nonresidential customers 30 kW or smaller) — *or* 50 percent of the standard demand charge plus the transmission and ancillary services charge (for larger customers). The standby charge is applied to the difference between the customer's *actual* demand during the billing month and the customer's *highest expected* demand (or the greatest *coincident total* of the customer's demand for its own generation and utility-supplied power).

Customers can choose their contract demand level. They pay two monthly "excess takings" charges for demand above that:

- An "overrun demand charge" for the difference between the highest measured demand and the contracted amount. For nonresidential customers 30 kW or smaller, the rate is four times the standard demand charge. For larger customers, the rate is four times the standard demand charge plus the transmission and ancillary services charge.
- An "overrun energy charge" for energy usage exceeding the contract capacity level. The rate is two times the energy charge in the customer's applicable schedule.

Portland General Electric. PGE began providing standby service to one large customer in July 2003. Standby service was originally provided under Rule L, in combination with the applicable full requirements schedule.[69] The Commission approved in December 2003 new consolidated standby tariffs for the company, subject to investigation.[70] One tariff was for customers choosing utility-supplied energy; the other was for customers buying energy from an alternative supplier. The consolidated standby tariffs provided an unbundled rate structure to distinguish each component of standby service.

Among them are two ancillary services, called generation contingency reserves. Spinning reserves enable the utility to supply power instantly when a generator on its system shuts down or reduces output. Supplemental reserves provide electricity within 10 minutes after such an event. Together, they transition customer loads to replacement power. For full requirements customers, the costs of these services are included in PGE's energy charge.

The Northwest Power Pool, under WECC standards, requires member utilities to carry these reserves for all generation in their control area — *including generation at customer sites* — if the utility is meeting WECC reliability standards through the "load responsibility" standard.[71]

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[68]PacifiCorp's response to OPUC data request, Jan. 5, 2004.

[69]Under Rule L, the customer paid for actual demand at the standard cost-of-service schedule rates. An additional standby demand charge was assessed for the difference between the customer's actual demand during the billing month and highest demand over the previous 11 months. The standby rate was 50 percent of the demand charge in the standard rate schedule.

[70]Docket No. UE 158, investigation into PGE Advice No. 03-19 approved at the Commission's public meeting on Dec. 4, 2003.

[71]WECC requirements for operating (spinning and contingency) reserves are based on the *greater of* the control area's (1) "most severe single contingency" (the largest generator or transmission line in the utility's control area *or* (2) the amount of generation supplying the control area's "load responsibility" ("…firm load demand plus those firm sales minus those firm purchases for which reserve capacity is provided by the supplier"). If a generator of any size is supplying firm load within the control area or making firm sales outside the control area, it must be included in the utility's load responsibility for determining its reserve requirement. See http://www.wecc.biz/documents/policy/WECC_Reliability_Criteria.pdf.

The Commission completed its investigation into PGE's standby rates in July 2004.[72] The new standby rates[73] include the following features:

- Generation with a nameplate capacity below 1 MW is exempt.
- Standby customers pay for facility capacity charges on the same basis as full requirements customers. These charges cover meter and other customer-specific costs that are not fully covered by the fixed basic charge, as well as the costs of 13 kV lines and utilization transformers (so-called "local" distribution facilities). The monthly charge is based on the average of the two highest monthly demand levels in the past year.
- For firm service, standby customers pay for shared distribution facilities (distribution substations and subtransmission lines) on the same basis as full requirements customers, except standby customers pay only for demand during on-peak hours (6 a.m. to 10 p.m., Monday through Saturday). The monthly charge (with no annual ratchet) is based on the highest demand during on-peak hours.
- Standby customers pay for transmission facilities on the same basis as full requirements customers. The monthly charge (with no annual ratchet) is based on the highest demand during the month. The charge is *not* applied to on-peak hours only because PGE does not currently face constraints on its transmission system, nor does the company anticipate constraints in the foreseeable future.
- Generation reserves charges are based on the nameplate capacity of the customer's generator, not to exceed the contract demand. The company does not impose reserves charges when the customer's generator is not scheduled to operate during the entire billing month. Charges are based on the FERC-approved rates in the company's OATT. The reserve requirement for consumers who can demonstrate their ability to instantly shed load upon generator failure is similarly reduced. Consumers that have a generator with a nameplate capacity of at least 15 MW can self-supply reserves.
- There's an initial three-month grace period for facility capacity and generation reserves charges so customers can work out the bugs of their generation and load shedding systems without incurring an annual charge based on outage events during an adjustment period.
- To meet the customer's energy needs under normal generator operation, the customer has the same choices as full requirements customers. Scheduled maintenance energy is charged at daily index prices, unless it's planned for an entire calendar month and the customer chooses the monthly market-based rate. Unscheduled energy is priced at the *hourly* Dow Jones mid-C index.
- Self-generating customers can choose an additional *interruptible* standby service, to buy "economic replacement power" when it is mutually beneficial to both the customer and PGE. Under this option, the customer and the company can agree to fix the monthly basic and facility charges. Charges for transmission and shared distribution facilities are on a *daily* basis and are differentiated by on- and off-peak hours. Energy rates are based on the *hourly* Dow Jones mid-C index.

Idaho Power. Idaho Power provides seasonal standby service for one Oregon customer, under a special contract.[74] The contract includes monthly standby charges, as well as excess demand charges on a daily and monthly basis. Daily demand charges are higher during April through August.

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[72]Order No. 04-400, issued July 19, 2004.
[73]Schedules 75 (firm) and 76R (interruptible) are for customers that buy energy from the utility; Schedules 575 (firm) and 576R (interruptible) are for customers that buy from an alternative supplier.
[74]Schedule 99, per Advice No. 98-12, approved by the Oregon Public Utility Commission on Oct. 20, 1998.

C. Some PURPA policies in Oregon may be outdated and need refinement.

Federal requirements for power purchases

Congress passed PURPA in 1978 to make the United States less reliant on fossil fuels. The law encourages electricity customers and independent power producers to develop efficient cogeneration plants and "small power production facilities" that produce electricity primarily from biomass, waste or renewable resources, including water, wind, solar and geothermal energy. These "Qualifying Facilities" represent most types of distributed generation.

Small power production facilities are limited to a nameplate capacity of 80 MW. Cogeneration facilities can be any size, so long as their useful thermal output is at least 5 percent of total energy output. If fueled by oil or natural gas, the plant must meet efficiency standards. Both types of facilities also must meet ownership criteria. A utility or other entity primarily engaged in the generation or sale of electricity may own no more than 50 percent of the facility.

The law ensures a market and fair price for the electric output of Qualifying Facilities by requiring utilities to buy it at their "avoided cost." FERC rules to carry out PURPA define avoided costs as the "incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[75]

Avoided cost rates for power purchases must be just, reasonable, in the public interest and nondiscriminatory.[76] FERC rules list factors to take into account in rates, such as savings from reduced line losses, the value of smaller capacity additions, dispatchability, reliability and whether deliveries are during peak hours.[77] FERC rules require utilities to submit avoided cost data for review by state regulators at least every two years.[78] Subject to these general guidelines, state regulators have broad discretion over the methodology for determining avoided costs and the terms and conditions for utility power purchases.

FERC rules require that Qualifying Facilities 100 kW or less be offered standard rates. The state regulatory authority may adjust that limit.[79]

Utilities must connect with and purchase all electricity made available by a Qualifying Facility located within their service territory. If the Qualifying Facility agrees, the utility may wheel the power to another utility, which must purchase the power as if the facility were supplying it directly. The facility owner pays for the wheeling.

Oregon requirements

Oregon began adopting laws (ORS Chapter 758.505, *et seq.*) and rules (OAR 860-029) in 1979 to implement PURPA at the state level. Under the state's electric restructuring law passed by the 1999 Legislature, PGE and PacifiCorp are no longer subject to these state statutes and rules.[80] However, the Oregon PUC retains its authority to implement federal PURPA rules.

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[75] 18 CFR §292.101(b)(6).
[76] 18 CFR §292.304(a).
[77] 18 CFR §292.304(e).
[78] 18 CFR §292.302(b).
[79] 18 CFR §292.304(c).
[80] ORS 757.612(4). Only Idaho Power remains subject to Oregon PURPA statutes and administrative rules.

Avoided cost filings. Oregon electric utilities conduct avoided cost studies for their integrated resource plans using a 20-year planning horizon. The plans are filed every two years.[81] After the Commission acknowledges the plan, the utility makes an avoided cost filing for Commission review and approval. The avoided cost filing includes any updates to information in the plan, as well as a revised tariff specifying non-negotiable purchase rates for Qualifying Facilities 1 MW or less. Rates are distinguished by on-peak and off-peak hours[82] and may be differentiated by season. For larger projects, the utility negotiates rates based on the Commission-approved avoided costs and adjustment factors outlined in PURPA.[83]

The avoided cost filing includes an estimate of when new resources will be needed to meet projected load growth. The filing also identifies the type of resource the utility plans to use to meet load growth (as defined in its resource plan) and to serve as the basis for calculating avoided energy and capacity costs. The utilities currently use as their incremental resource in their resource plans a natural gas-fired CCCT.

Historically, avoided costs in Oregon have been calculated using: (1) the variable costs of operating existing generating facilities until projected supply deficits occur and (2) when new resources are needed, their estimated capacity and energy costs. The avoided costs are calculated for 20 years, consistent with the time horizon the utility considers in its resource plan.

How avoided costs are calculated is among the issues the Commission is reviewing in UM 1129.

Term of power purchase contract. Today, Oregon investor-owned utilities offer a five-year contract for Qualifying Facilities. The contracts are renewable, but at rates based on the new avoided costs and only if the federal PURPA law remains in effect.

The Commission first limited Qualifying Facility contracts to a five-year term in 1996.[84] The term limit was intended to keep contract prices relatively consistent with the utility's actual costs of new resource acquisition. At the time, the utilities were signing contracts for no longer than five years and were planning to rely on the wholesale market for much of their energy and capacity needs.

The Commission's 1988 report to the Legislature on Qualifying Facilities in Oregon provided further support for adoption of a five-year term limit.[85] The report concluded that electric utility rates were higher than they would have been in the absence of Qualifying Facilities. The reasons were inaccurate load forecasts and resource cost estimates used to determine avoided costs. A key problem was requiring a 35-year projection of avoided costs — and fixed payments based on that projection — over the same contract term.

Beginning in the mid-1980s, market prices began to deviate substantially from the avoided cost estimates. To help spur competition in the electric industry, in 1989 the Commission began an

[81]See Order No. 89-507.
[82]A weighted rate based on the ratio of on- and off-peak hours applies where there is no time-of-use or interval meter.
[83]See OAR 860-029-0040(5) for Idaho Power. See 18 CFR §292.304(e) for PGE and PacifiCorp.
[84]PGE Advice No. 96-21, approved by the Oregon Public Utility Commission Dec. 17, 1996. Subsequently, the Commission approved avoided cost filings for PacifiCorp and Idaho Power with a five-year limit on Qualifying Facility contracts.
[85]Oregon Public Utility Commission, ***Report to the Sixty-Fifth Legislative Assembly and Energy Policy Review Committee: In the Matter of an Investigation Into the Impact of Cogeneration and Small Power Production Facilities***, Nov. 1, 1988.

investigation into the use of competitive bidding. Its competitive bidding order[86] in part directed the utilities to revise their avoided costs to reflect market information gained in the bidding process. Utility-constructed plants and wholesale purchases also may be used in the calculations.

Today, the utilities are pursuing five- to 20-year contracts for thermal resources and 20- to 30-year contracts for renewable resources. They also are acquiring large 30-year, utility-owned resources.

Whether the contract term offered to Qualifying Facilities today should be lengthened is another issue the Commission is reviewing in UM 1129.

Size limit for standard avoided cost rates and contracts. Oregon investor-owned utilities file non-negotiable avoided-cost rates for Qualifying Facilities 1 MW or smaller. In its 1991 order establishing the current size threshold for standard rates,[87] the Commission cited a staff report that stated, "…[T]he transaction costs associated with negotiating a QF/utility power purchase agreement could be prohibitive for small QFs and effectively eliminate them from the marketplace."[88]

At the time the Commission issued this order, it assumed that larger Qualifying Facilities would be able to compete in utility solicitations. However, the availability of low-cost power on the wholesale market in the 1990s, and then electric industry restructuring, created little interest in competitive bidding. The utilities began issuing solicitations under the competitive bidding order in 2003.

The Commission is reviewing in UM 1129 whether Qualifying Facilities larger than 1 MW should be eligible for standard avoided-cost rates and other terms and conditions.

D. Customers can't easily sell power from on-site generation to the utility through a competitive bidding process, to a marketer or to other customers directly.

In theory, customer-sited generation can compete in utility resource solicitations with utility self-build or turnkey options, as well as large independent power plants. In reality, however, there are a number of barriers.

First, small projects may not be eligible to participate in those solicitations. That's because it's difficult for the utilities to review bids from small projects when the companies need to acquire hundreds of megawatts of capacity. So they set minimum size requirements. For example, PGE's request for proposals (RFPs) for supply-side resources required renewable resources to meet a standard of 5 aMW expected output each year. Other types of projects, including cogeneration facilities, had to be capable of producing 25 MW every hour of the year. PacifiCorp's RFP for renewable resources required projects to be capable of delivering 70,000 MWh per year. For wind, that's a 24 MW facility. [89]

[86]Order No. 91-1383.
[87]Prior to that time, the size limit in Oregon for standard rates was 100 kW, the minimum size required under federal rules.
[88]Order No. 91-1605 at 2.
[89]PacifiCorp's RFP 2003-A, for baseload, peaking and super-peaking resources on the East side of its system, allowed systems as small as 1 MW to bid.

In addition, negotiating rates and other terms and conditions with the utility adds time and cost to the process.

Further, the timing of utility solicitations may not coincide with the needs of customers and third-party developers. Cogeneration projects, for example, may make most sense when a company first develops a site, expands its production line or replaces equipment.

Moreover, utilities have little incentive to buy energy from customer-sited generation. They can earn a return on a generating plant only when they own it, not when they simply buy power, and they don't have the same opportunity to profit from the operational flexibility of the facilities. Further, customer generation reduces utility sales.[90]

The wholesale market also is not a likely avenue in Oregon today for most distributed generation projects. Generating customers will have a difficult time selling to a marketer unless they have at least 25 MW of energy to sell, the standard trading block. They also will have difficulty obtaining agreement with a marketer on assignment of risks and responsibilities. Further, it can be difficult to get sufficient firm transmission rights to move the power outside the utility's system, and it's highly complex to execute a transmission agreement — something that's difficult for small facilities in particular. And the cost of transmission system studies, required transmission upgrades for interconnection, transmission services, and losses for wheeling the power outside the utility's service area may make the sale uneconomic.

Distributed generators could sell to nonresidential customers in PGE's and PacifiCorp's service areas. But, like selling to a marketer, that adds another layer of requirements, contracts and costs, compared to selling to the utility. The generating customer would have to meet the utility's requirements for Electricity Service Suppliers (ESSs), including credit and electronic data exchange requirements. Further, the generating customer would have to be certified by the Oregon PUC as an ESS if it sells to more than one customer.[91,92]

Depending on the point of interconnection and delivery, the generating customer (or purchaser) would need to buy distribution and/or transmission service from the utility. Oregon utilities don't have tariffs filed with the Commission for customers or third parties wanting to wheel power over the distribution system where the Commission has jurisdiction. The generating customer also would need to provide a scheduling coordinator for the transport of power with the utility, just as it would if it were selling to a marketer. There also could be imbalance charges for under- and over-deliveries.[93]

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[90]Except for buy-sell arrangements, where the utility serves the full requirements of the customer (the generation isn't used to displace load) and buys all of the facility's output.
[91]OAR 860-038-0005(24).
[92]The customer-generator also would be considered a public utility subject to Commission regulation unless it met one of the exceptions in ORS 757.005, including solar and wind projects, selling to fewer than 20 residential customers, and Qualifying Facilities selling to Idaho Power (the only utility not exempt from Oregon's PURPA law). The Commission has proposed legislation (SB 171) to reinstate the exemption for Qualifying Facilities in PGE and Pacific Power territories. Senate Bill 1149 (1999 Oregon Legislature) inadvertently removed the exemption for Qualifying Facilities selling to these utilities.
[93]PGE's and PacifiCorp's responses to OPUC data requests, May 6 and May 13, 2003, respectively.

E. Utility planning for energy and capacity needs is done in isolation from distribution and transmission system planning, and neither generally considers distributed generation.

Planning for energy and capacity resources
Integrated resource planning in Oregon provides an opportunity for public review and Commission acknowledgment of the utilities' proposed investments in energy and capacity resources. The plans must meet four substantive requirements:[94]

- They must evaluate resources on a consistent and comparable basis.
- They must evaluate how alternate resource options perform given future risks and uncertainties.
- Their primary goal must be to acquire the least-cost resources, consistent with the public interest over the long run.
- They must be consistent with the state's energy policy, which includes promoting efficient use of energy resources and permanently sustainable energy resources.[95]

The plans have not focused on acquiring new distributed energy resources. Among the reasons utilities cite:

- *Qualifying Facilities can request a utility PURPA contract anytime, so there's no way to plan for them. Similarly, utilities say they don't know their customers' plans for investing in generation, so they can't count on customer-sited generation for resource planning.* The utilities know their large commercial and industrial customers well, including who would be candidates to develop or host a facility. The utilities also know the weak points in their distribution and transmission systems and planned system upgrades that may be candidates for deferral through customer-sited generation. Utilities can have a say in distributed generation at customer sites through sole or joint ownership,[96] through a power purchase agreement, or by providing incentives that reflect up to the value of the project in deferring a planned grid investment.

- *Distributed generation can participate in utility resource solicitations like any other resource.* Problems with this approach are outlined earlier in this report. Moreover, a factor in whether a distributed resource project is economic for the utility system is its deferral value for any planned distribution system upgrade. But Oregon's resource planning and competitive bidding processes do not consider distribution system needs. So there's no accounting for any deferral value for avoiding distribution system costs if the generator could reliably defer a planned investment.

- *Customer-sited generation is not dispatchable.* It can be. For example, TransCanada's 720 MW combined-cycle cogeneration plant at the BP Cherry Point Refinery in Blaine, Wash., will be fully dispatchable.[97] However, calling on a CHP facility at a time when there is no use for the thermal energy can substantially reduce system efficiency, increasing operating costs. Further, to be competitive, facilities need to run at the highest possible capacity

[94] Order No. 89-507.
[95] ORS 469.010(2).
[96] If the utility owns more than 50 percent of the facility, it would not qualify for PURPA status.
[97] While the local utility is not involved in the project, it serves as an example of how even a very large CHP project can be dispatchable — through backup boilers and demand response measures. The refinery will use the steam and 100 MW of power via a 25-year contract, 450 MW will be contracted to third parties, and TransCanada will sell the balance through its trading operations. The project is expected to be in commercial operation in 2006.

factor. Utilities can negotiate dispatchability and other operating arrangements in power purchase agreements.[98]

Distribution and transmission system planning

Oregon energy utilities must submit by November 1st each year an annual construction budget for major distribution and transmission investments for Commission review.[99] The utilities report on new construction, as well as extensions and additions to their property, for all projects that cost more than $10 million. The Commission is not required to take any action on the filings.[100]

Annual construction budgets for distribution and transmission system projects often exceed construction budgets for generating resources. Construction budgets the utilities filed over the past several years give a sense of the magnitude of these investments (Table 7).

Table 7. Distribution and Transmission Construction Budgets
(millions of dollars)

PacifiCorp
(system-wide)

	2001	*FY2002*	*FY2003*	*FY2004*	*FY2005*
Distribution	$225.3	$203.4	$187.4	$277.8	$295.8
Transmission	$51.6	$36.5	$61.1	$57.5	$91.1

Portland General Electric

	2001	*2002*	*2003*	*2004*
Distribution	$101.3	$117.9	$103.9	$105.2
Transmission	$12.0	$9.2	$5.0	$6.6

Idaho Power
(system-wide)

	2001	*2002*	*2003*	*2004*
Distribution	$56.4	$56.9	$50.2	$56.5
Transmission	$21.0	$17.7	$36.1	$33.6

Requirements for new or upgraded distribution facilities — and their costs — vary widely from one area to another. Customers and independent power producers, however, don't have the information or incentives they need to develop distributed generation in areas where the utility would otherwise invest in expensive grid upgrades.

That's in part because only the utilities have this information. It's also because rates to recover distribution system upgrades are spread uniformly over the utility's entire service area. So there are no locational price signals to stimulate competition from distributed generation at customer sites to meet those needs. Consequently, distributed generation that could be installed economically in lieu of more costly upgrades to the grid is not, whether by utilities, customers or third parties.

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[98] For facilities that do not qualify for standard avoided cost rates and a standard power purchase agreement, or those that agree to a contract outside of PURPA.
[99] Including meters. See OAR 860-027-0015.
[100] "[U]nless rejected within 60 days, the proposed budget is presumptively fair and reasonable and not contrary to public interest." ORS 757.105(3).

The Regulatory Assistance Project[101] has recommended ways to determine the most beneficial locations for distributed generation and to credit distributed generators in these areas for benefits they provide:

- Require the utilities to file periodically with the Commission a list of all proposed major distribution upgrades, say investments of at least $1 million, and their levelized cost per kilowatt, to indicate where distributed generation should be evaluated to determine if it might be more cost-effective than traditional grid investments. The utilities also would list what load reduction, by what date, would allow those investments to be deferred.

- Require the utilities to report areas with the worst reliability record, by substation and feeder. These areas may be candidates for distributed resources that can improve reliability.

- Designate "distributed generation development zones" for these strained areas of the grid, and provide a standard distribution credit for all qualifying distributed resources that locate in the area.

Any credits for distributed generation facilities would be provided only until distribution capacity investments can no longer be deferred. The amount of the credits would not exceed the savings from deferring or avoiding the upgrades. Further, credits would be tied to the operation of the distributed generation facility during the hours that the congested transformer, feeder or substation is near peak use.

Another way to assess how distributed generation can support the grid is through "Local Integrated Resource Planning," which recognizes that distribution system investments are driven by local (not system-wide) peak demand. Unlike traditional planning which works from remote central generation downstream, this approach starts with specific end uses and neighborhoods where efficiency, demand response and local generation would best defer or avoid costly grid investments, and then works its way upstream toward the generator to see which resource mix would meet customers' needs at least cost. Utilities that have conducted such analyses include Ontario Hydro, PG&E, Southern California Edison, and New York State Electric & Gas Co. The result is improved utilization of distribution assets and avoidance of costly distribution system upgrades.[102] The utility can make the investment in distributed generation itself, or partner with customers or third-party providers.

RFPs are another option for determining whether distributed generation is more cost-effective than traditional grid upgrades for relieving congestion. Assuming it meets all the requirements in the solicitation, any proposal that requires an incentive payment that is less than the value of deferring the upgrade would benefit ratepayers. The distributed generation project could be owned by the utility, the customer, a third party or any combination of these.

New York adopted a pilot program designed to develop policies and procedures for integrating distributed generation as an alternative to the utilities' planning process for distribution system improvements.[103] The objectives of the pilot program are:

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[101] David Moskovitz, Regulatory Assistance Project, *Distributed Resource Distribution Credit Pilot Programs: Revealing the Value to Customers, September 2001.* Other reports by the Regulatory Assistance Project that cover these topics include *Costing Methodology for Electric Distribution System Planning,* 2000, and *Distribution System Cost Methodologies for Distributed Generation*, 2001.

[102] Lovins, *et al.*

[103] New York Public Service Commission, Opinion No. 01-5, Case 00-E-0005, *Opinion and Order Approving Pilot Program for Use of Distributed Generation in the Utility Distribution System Planning Process*, Oct. 26, 2001.

- To determine whether distribution system needs can be satisfied on a least cost basis by creative and competitive means
- To develop information on distributed generation costs, benefits and impacts across a range of distribution system conditions
- To refine methods for evaluating proposals for customer-owned distributed generation against traditional system improvement projects
- To determine whether a competitive bidding process is a viable means of eliciting market response to the utility's distribution system needs

None of the bids in the first two rounds of solicitations was a cost-effective alternative to a traditional distribution system upgrade, in large part because the proposals did not include a host customer that would pay for the byproduct steam or heat from cogeneration.

The California Public Utilities Commission requires that investor-owned utilities consider independently owned distributed generation as an alternative to distribution system investments.[104] In 2003, the Commission ordered the utilities to develop a methodology for evaluating distributed generation as an alternative to distribution system projects, inform potential providers of locations where distributed generation might defer planned projects, procure distributed generation in lieu of a traditional grid upgrade if it's cost-effective, develop model contracts as a starting point for negotiations, and pay providers through a bill credit or direct payment.[105]

As a result of a solicitation for grid reliability resources, San Diego Gas & Electric Co. selected 25 MW of customer-owned distributed generation aggregated and networked by a third party to provide full dispatchability and immediate load-shedding capability.[106] The project is similar to Bonneville Power Administration's pilot project on the Olympic Peninsula mentioned earlier in this report.

Similarly, EPRI's Electricity Innovation Institute[107] convened a group of stakeholders to work with one of the utilities, Southern California Edison (SCE), on an RFP for distributed generation services to defer distribution system projects. The goal is a model for utility procurement of services that could cost-effectively defer grid upgrades in a manner where the utility and other stakeholders can benefit (and none are worse off).

The group is finding solutions to several problems that the New York process highlighted. For example, SCE has agreed to publish a market reference price, with confidentiality provisions, so that potential developers know whether it's worthwhile to spend the time and expense to submit a bid. California relies on "physical assurance" for reliability so the utility can count on the generator to operate when it needs it for alleviating constraints on the grid. Initially, the utility was going to require instantaneous load shedding at the host customer's site any time the generator trips off-line. The group worked with SCE to minimize the number of hours for which physical assurance must be required. The result is that the customer's contract is expected to require physical assurance between 200 hours and 400 hours – the period during which the distribution system upgrade would have been required.[108]

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[104] Rulemaking 99-10-025.
[105] Decision 03-02-068, issued Feb. 27, 2003.
[106] R.01-10-024, Opinion Approving Motion of San Diego Gas & Electric Company (U902E) for Approval to Enter Into New Electric Resource Contracts Resulting From SDG&E's Grid Reliability Request for Proposals. Other generation resources and small, aggregated demand response resources also were selected.
[107] The Electric Power Research Institute has taken over the functions of the institute.
[108] For more information on the project, see http://www.e2i.org/e2i/der_partnership/partnership.html.

New South Wales, Australia, is using a broader approach.[109] As part of electricity industry restructuring in 1995, each distribution utility is required "…before expanding its distribution system … to carry out investigations … to ascertain whether it would be cost-effective to avoid or postpone the expansion by implementing [demand management] strategies … where it would be reasonable to expect that it would be cost-effective."

To carry out this requirement, a group of utilities and stakeholders developed a Demand Management Code of Practice that requires utilities to:

- File annual Electricity System Development Reviews that disclose detailed data about capacity, load and planned investments
- Adopt a transparent, competitive process for assessing and procuring alternative solutions to distribution system constraints to ensure "…that all supply and demand side options developed by customers or third parties and by the Distributor itself can be developed and evaluated at the same time and in the same manner as network augmentation."

The utilities have issued RFPs, but development of projects has been slow. Among them is an energy efficiency project that will reduce peak load by 1.35 MW, deferring a planned $1.5 million investment to increase capacity of lines supplying a substation. The value of the deferral is $500/kW-year.[110]

F. The utilities' revenues are based on how much power they sell and move over their wires, and they lose sales when customers develop generation on site. Utilities also do not earn a return on non-utility resources or make profits on them through operational efficiencies.

PGE, for example, cites cost recovery based on throughput as a barrier to accommodating distributed generation on its system: "The current misalignment between cost causation and pricing does indeed provide incentives and disincentives to utilities, that, we believe, are contrary to sound public policy. There is an incentive to try to increase loads. There is a disincentive to do anything that decreases loads.… To the extent that a customer installs distributed generation to reduce its usage of utility supplied energy, it will reduce system throughput, and thus earnings. This is a powerful incentive (or disincentive) to the utility."[111]

Reduced sales are mainly a problem between rate cases and for delivery revenues (because energy can be sold on the market).

Distributed generation also can defer or even eliminate the need for some distribution and transmission projects, reducing the opportunities utilities have to earn a return on investments. (On the other hand, distributed generation sited in the right places can reduce utility costs between rate cases.)

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[109] Chris Dunstan, Sustainable Energy Development Authority of New South Wales, *Camel Chiropractics: The New South Wales Demand Management Code and Mapping Demand Management Opportunities*. Demand management includes energy efficiency, peak load management and distributed generation. Also see *NSW Code of Practice: Demand Management for Electricity Distributors*, September 2004 (www.deus.nsw.gov.au/publications/index.htm).

[110] For a summary of other non-wires case studies, see Richard Sedano, Regulatory Assistance Project, "Non-Wires Alternatives: Case Studies," presentation to the Oregon Public Utility Commission, Dec. 16, 2004.

[111] From Direct Testimony of Randy Dahlgren and Sara Cardwell, UE-126, Oct. 11, 2001.

Further, utilities may prefer their own resources over distributed generation primarily because they can rate base their investments and make profits between rate cases by taking advantage of operational efficiencies at their own plants.

PGE has recommended "distribution decoupling as a means to ensure an equitable structure for distributed resource development."[112,113] That is, a revenue cap could be established based on projected revenue requirements for distribution system investments, as well as a balancing account to make up any revenue shortfalls or over-collections.[114]

Alternatively, the Commission could consider a targeted margin recovery mechanism for distributed generation. The utility would track shortfalls in distribution revenues due to new distributed generation in its service area and recover the losses until distribution rates are reset in the next general rate case.

Still, there would be no *incentive* for utilities to promote distributed generation. The Commission could consider performance-based ratemaking — including, for example, shared savings incentives for achieving cost reductions through customer-sited generation. Another option is allowing utilities to include in rate base their investments in distributed generation at customer sites, even when the utility has no ownership.

The combination of utility disincentives and lack of incentives makes it difficult for customers and third parties to develop distributed generation. Timely agreements with the utility are important for a variety of reasons, including financing opportunities as well as project deadlines for building construction, new production lines or equipment replacement. The result is missed opportunities for cost-effective projects.

Other regulatory barriers

Potential regulatory barriers beyond the Commission's reach include:

Siting and permitting — Most distributed generation projects are exempt from the state's siting process because of their size or because they use cogeneration technologies that meet efficiency standards. Instead, the city or county is responsible for siting and permitting. Delays and additional costs are likely for projects where siting and permitting standards have not been established. The Oregon Department of Energy has developed model siting standards to help local governments plan for siting decisions and clarify the process for developers. Local code officials need training and technical help to better understand how to apply state standards and code interpretations to ensure timely approval of installations.

Air quality permits — Emissions of greenhouse gases and other pollutants from distributed generation technologies range from zero to quite high. Expansion of distributed generation could lead to higher levels of pollution unless the state encourages clean technologies.

A 30-member group of state utility regulators, state environmental regulators, representatives of the distributed resources industry, environmental advocates and federal officials developed model rules for states for emissions standards for distributed and other generation facilities that

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[112]PGE's response to OPUC data request, July 3, 2002.
[113]The Commission denied PGE's decoupling proposal in Order No. 02-633. However, the Commission previously allowed decoupling for PGE during most of 1995 and 1996 (Order No. 95-322) and adopted a decoupling mechanism for PacifiCorp's distribution-related revenues as part of an alternative form of regulation in Docket No. UE 94. (See Order No. 98-191.)
[114]Any rate increases needed to make up a shortfall could be timed to minimize the volatility of customers' bills.

are not regulated directly under the federal Clean Air Act.[115] States can adopt the rules in whole or adapt them to foster the deployment of environmentally sustainable and economically efficient generation.

The rules regulate five emissions: nitrogen oxides, particulates, carbon monoxide, sulfur dioxide and carbon dioxide. The standards are based on the useful energy output of the system (including heat), rather than the amount of fuel consumed, as well as whether it's used to meet baseload, peaking or emergency needs. The standards are technology- and fuel-neutral, with the exception that sulfur dioxide is addressed through fuel sulfur content.

The general premise of the standards is the more a generator operates, the less polluting it must be. Emissions limits are based on what current technologies can achieve or are expected to achieve over the next decade. There are three phase-in periods, during which emissions limits are ratcheted down.

The rules are broken down by emergency and non-emergency needs. Emergency generation is limited to 300 hours of operation annually, of which a maximum of 30 hours may be for maintenance operations. All other uses are non-emergency. The limits for emergency generators are equivalent to US EPA standards for off-road engines. For other generators, nitrogen oxide limits are differentiated for attainment vs. non-attainment areas in the earlier phase-in periods.

In addition to these standards, a precertification system would speed approval for air emissions permits for some projects. Air quality agencies could approve specific equipment as meeting emissions standards without further review.

[115]Regulatory Assistance Project, *Model Regulations for the Output of Specified Air Emissions From Smaller-Sale Electric Generation Resources*, Oct. 31, 2002.

RECOMMENDATIONS

Staff makes the following recommendations to remove regulatory barriers to development of distributed generation. The recommendations appear in the same order as the previous section's listing of barriers they are intended to relieve.[116]

Some recommendations are directed at small-scale applications — net metering changes, for example. Implementation of other recommendations would have potentially greater impact because they would foster larger projects, resulting in more energy from distributed resources and at a more economic cost.

Staff previously recommended that the Commission identify policies that facilitate adoption of advanced metering and communication technology to improve demand response capability. An investigation into this matter is just getting underway (UM 1188). In addition to controlling customer loads and allowing more pricing options, two-way communications at customer meters can help utilities better understand load patterns, control and monitor distributed generation, and assess the potential benefits of distributed generation in reducing distribution system costs.

1. The Commission should implement uniform technical standards, procedures and agreements for interconnecting generators.

Staff plans to convene informal workshops in 2005 on interconnection issues under the Commission's jurisdiction, prior to requesting a formal proceeding to adopt interconnection rules.

Among the prototypes staff may consider as the basis for the rules:
- NARUC's model procedures and agreement
- FERC's interconnection rules[117]
- IEEE 1547
- State standards, including those in Texas, California, Massachusetts, New York, Ohio, Delaware, New Jersey and Wisconsin
- Pennsylvania-New Jersey-Maryland interconnection standards
- Interstate Renewable Energy Council's model standards

2. The Commission should adopt in PacifiCorp's rate case (UE 170) standby tariffs that properly reflect the costs and benefits of serving customers with distributed generation.

The Commission adopted new standby rates for PGE in July 2004. PacifiCorp proposes similar changes to its standby rates in its current rate case. In UE 170, PacifiCorp proposes to:

- Eliminate separate provisions for partial requirements service for customers with generation under 1 MW. These customers would be billed for energy and capacity on the same terms and conditions as any other customers.

[116] The first recommendation is designed to address barrier "A," etc.
[117] FERC's proceeding on interconnection rules for small generators is still underway.

- Eliminate present standby and overrun charges. In their place and consistent with standard delivery service schedules, customers would pay a monthly facilities charge based on the average of the two highest non-zero monthly demands during the past year and a monthly demand charge based on peak demand during the billing month.
- Charge standard supply-service prices for baseline usage (usage occurring when the customer's generator is running) as well as replacement power during maintenance scheduled according to the proposed tariff.
- Base energy charges for unscheduled outages on hourly market prices.
- Separately charge for spinning and supplemental reserves costs for the customer's generation supplying load. Customers can avoid these charges by shedding load in required timeframes or when their generator is not scheduled to operate for the entire billing month.

The rate case will be completed in September 2005.

3. Through UM 1129, the Commission should extend the contract length for Qualifying Facilities, increase the size eligible for standard purchase rates, establish Commission-approved standard purchase agreements for facilities eligible for standard rates, and review methods for valuing avoided costs when a utility is resource-sufficient. To mitigate risk to ratepayers of long-term, must-take contracts, the Commission should allow fixed pricing under standard PURPA rates and contracts only for small Qualifying Facilities.[118]

The Oregon Commission began its investigation (UM 1129) into investor-owned utility purchases from Qualifying Facilities in January 2004. Issues being addressed include calculation of avoided costs, size threshold for standard rates, contract length, and other terms and conditions. The Commission is expected to issue an order in this proceeding in spring 2005.

4. The Legislature should add biomass as a qualifying resource for net metering and allow the Commission to increase the eligible project size for PGE and PacifiCorp.

Net metering means that the generating customer pays only for its net take from the utility. For example, a homeowner with a solar electric system may send energy to the electric grid during the day and take energy from the utility at night. The customer's monthly bill charges only for net use. In Oregon, net metering customers who produce more power during the billing period than they use get a credit on their bill at the utility's avoided energy cost.[119]

Oregon's net metering law[120] provides the only quick, simple and inexpensive way for customers to connect to the grid and sell excess energy. The law requires all electric utilities[121] to allow customers to interconnect eligible systems to the electric grid under established state and national standards, without having to pay for any interconnection study, tests or equipment beyond what those standards require. Further, the utility may not impose liability insurance

[118]See footnote 2.
[119]Generation credit and other terms are specified in Schedules 201 and 203 for PGE customers and Schedule 135 for PacifiCorp customers. These are the same avoided cost rates for PURPA facilities.
[120]House Bill 3219 (ORS 757.300), effective Sept. 1, 1999.
[121]Idaho Power is required to offer net metering to its Oregon customers in accordance with tariffs and requirements approved by the Idaho Commission (ORS 757.300(8)).

requirements or additional fees such as standby charges.[122] Also, the interconnection agreement is simpler, so customers don't have to pay attorney fees for review.

The law applies only to very small generators, 25 kW and less, and certain types of systems — solar, wind, hydro and fuel cells. The generator also must be intended primarily to offset all or part of the customer's electricity requirements.

There are safeguards built into the law to ensure the safety and reliability of utility systems. First, net-metered systems must meet safety and performance standards in the state building code, and those must meet national standards. The customer pays for any equipment needed to operate safely and reliably in connection with the utility system. Second, the regulatory body (the Oregon Commission, for the investor-owned utilities) can adopt additional control and testing requirements if needed.

The Commission can limit additional net-metered systems in the service areas of PGE and PacifiCorp after they account for one-half of one percent of the utility's peak load. PGE's limit is 20,365 kW; PacifiCorp's is 15,234 kW.[123] The capacity of net metering systems to date is a small fraction of these levels – some 163 kW in PGE's service area[124] and 451 kW in PacifiCorp's service area.[125]

More than 30 other states have net metering requirements. Differences among states include which resources, customers and generator sizes are eligible, limits on generation capacity in the utility's service area, carry-forward provisions for excess energy (annual netting of energy production accommodates the seasonal nature of intermittent resources), and whether payment is based on the full retail rate or the avoided energy cost only.

Many states allow larger systems than Oregon does. Among the states at the upper end of the size range, California has a 1 MW net metering limit for solar and wind systems, and the New Jersey Board of Public Utilities recently raised the net metering size limit to 2 MW. Wind, solar, fuel cells that run on renewable resources, ocean power, and certain types of biomass facilities are eligible in that state.

Today in Oregon, wind turbines sized for farms and community projects, and fuel cells designed for loads larger than 25 kW, are not eligible for net metering. Increasing the size of eligible systems would encourage the use of wind turbines in rural areas and, as the cost of fuel cells comes down, spur their adoption by businesses and institutions. These technologies hold promise of being cheaper in the long run and are less harmful to the environment compared to traditional power plants. And fuel cells produce heat that consumers can use on site. That makes them far more efficient than most power plants, where the majority of the fuel's energy value is wasted before it reaches consumers.

Biomass resources such as agricultural and forestry waste are not eligible for net metering in Oregon. These energy resources are abundant, clean and renewable. Biomass fuel also has the advantage of continuous supply unlike solar, wind and hydro resources, which at times produce no power.

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[122] Unless the regulatory body determines that the utility's costs for net metering outweigh the public benefits of allocating those costs to all customers.
[123] Specified in PGE Schedule 203 and PacifiCorp Schedule 135.
[124] PGE's response to OPUC data request, Sept. 28, 2004.
[125] PacifiCorp's response to OPUC data request, Oct. 10, 2004.

The Commission has proposed legislation (SB 84) to add biomass[126] as a qualifying resource and to allow it to conduct a rulemaking to set a higher eligible facility size for net metering in PGE's and PacifiCorp's service areas.

Any financial impacts on the utilities and their customers that might result from allowing larger systems to be net metered will be minimal. First, the Commission can limit net metering to a fraction of peak load. Further, wind, hydro and solar resources typically produce no energy at some time during the month or during some seasons. Most businesses have meters that measure their peak demand each month, which will remain largely unchanged. Distribution rates for most businesses are based on demand, not usage, charges.[127] So the utilities' distribution revenues will remain about the same from customers that will participate in net metering as a result of any increase in facility size for intermittent resources.

5. The Commission should explore issues related to customer-generators selling power to other retail customers over the distribution system.

The states have jurisdiction over sales using the distribution systems of investor-owned utilities when they do not involve sales for resale.[128] Oregon's restructuring law requires the Commission to "ensure that an electric company that offers direct access…[p]rovides electricity service suppliers and retail electricity consumers access to its transmission facilities and distribution systems comparable to that provided for its own use…."[129]

The Public Utility Commission of Texas, for example, required the utilities it regulates to file tariffs that govern the rates, terms of access and conditions for providing distribution service to competitive retailers and retail customers on a nondiscriminatory basis (without regard to the affiliation of the competitive retailer or its retail customers).[130]

Among the issues the Oregon Commission should address are access to the utility distribution system and transparent, cost-based rates for using the system to wheel power to retail customers. A related issue the Commission should explore is enabling a customer-generator to use the distribution system to provide power to another of the customer's noncontiguous locations.

6. The Commission should investigate how to include distributed generation in utility planning and acquisition processes to meet energy, capacity, distribution and transmission system needs at the lowest cost.

Integrated resource planning in Oregon to date has only considered how to meet energy and capacity needs. It also has largely ignored the potential of new generation at or near customer sites to meet these needs, as well as the potential of distributed generation to reduce

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[126] As defined in ORS 757.600(28).
[127] PGE's small business customers (30 kW and smaller) do not have demand meters. Their distribution charges are based on kilowatt-hour usage. PacifiCorp's small business customers are charged for distribution in part based on demand, and in part based on usage.
[128] FERC has jurisdiction if the facility sells power for resale.
[129] ORS 757.637.
[130] Public Utility Commission of Texas, Order No. 121300, project number 22187, adopted Dec. 13, 2000. P.U.C. Subst. R. §25.214, Terms and Conditions of Retail Delivery Service Provided by Investor Owned Transmission and Distribution Utilities. A competitive retailer is an alternative electricity supplier serving retail customers in competitive electric power markets or "any other entity authorized to provide Electric Power and Energy in Texas." The tariffs do not apply to delivery service to wholesale customers.

distribution and transmission system costs. The Commission has included the following issues in its investigation into least-cost planning requirements (UM 1056):

- How should distributed generation be explicitly included in least-cost planning?
- How should transmission and distribution system investments/costs be incorporated into least-cost planning?

At the same time, utility planning for distribution and transmission needs does not systematically assess whether distributed generation and other non-wires alternatives could reduce costs in some cases.[131] The Bonneville Power Administration, for example, has incorporated into its planning process for all capital transmission projects over $2 million a screening process for non-wires alternatives. Bonneville also is sponsoring pilot programs to test technologies, resolve institutional barriers, and build confidence in using non-wires solutions.

The Commission should explore developing guidelines for utilities for evaluating whether distributed generation and other non-wires alternatives can cost-effectively and reliably defer or avoid certain types of distribution and transmission system investments, and where appropriate, obtain the lesser-cost alternative.

Among the first steps the Commission should take is a rulemaking requiring that economic non-wires alternatives be considered. A Commission investigation could develop screening guidelines for determining whether a planned grid investment is a candidate for non-wires alternatives as well as guidelines for analyzing alternatives for cost-effectiveness, reliability and other requirements.

In addition, the Commission should explore pilot programs with the utilities and stakeholders to test approaches for acquiring non-wires solutions, such as:

- RFPs
- Establishing credit rates for non-wires solutions up to the avoided cost of the traditional investment
- Including transmission and distribution deferral values in utility demand response programs and acquisition of distributed generation where these measures would reliably reduce peak demand in areas that are constrained or have reliability problems
- Energy Trust of Oregon programs that reduce peak demand on the utility system in targeted areas
- Partnering with Bonneville Power Administration on non-wires solutions

The Commission also should evaluate barriers to non-wires alternatives, including regulatory issues such as recovery of expenditures and accounting treatment, and develop ways to overcome barriers.

Further, to improve transparency about system needs, the Commission should assess what type of information the utilities should file annually along with their construction budgets to indicate areas of emerging grid constraints. Such information could include mapping network capacity, current and projected loads, planned investments (MW, location and date) and deferral values, as well as a report on investments screened for non-wires solutions.

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[131] In addition to distributed generation, non-wires alternatives include demand response, energy efficiency programs targeted to peak loads, and technologies that increase line carrying capacity.

7. The Commission should explore mechanisms for removing disincentives for utilities to facilitate cost-effective distributed generation at customer sites.

In the ongoing investigation into regulatory policies affecting new resource development (UM 1066), staff recommended that the Commission explore performance-based regulation to mitigate the utilities' bias toward owning resources and to encourage utilities to make the best resource decisions for customers.[132]

Investigating the use of performance-based rate-making is among the activities included under the Commission's 2005-06 objectives. The activity falls under the first of three Commission objectives: to adopt regulatory policies that encourage utilities and customers to meet energy needs at the lowest possible cost and risk.

In addition to a broad mechanism for performance-based regulation, the Commission could consider a targeted margin recovery mechanism for customer-oriented, demand-side resources — distributed generation and demand response. The Commission also could consider decoupling of distribution sales and revenues. In addition, the Commission could consider shared savings to promote non-wires alternatives for meeting distribution and transmission system needs.

Staff recommends that the Commission open a separate docket to address these issues.

8. The Commission should consider approval of a utility's request for accounting treatment that would allow a return on its capital investments in customer-owned distributed generation, similar to that previously approved for investments in conservation.

When a utility builds a generating resource, prudent capital investments in the asset traditionally have been included in rate base. That allows the company the opportunity to earn its authorized rate of return to recover its cost of equity and debt.

Allowing utilities to include in rate base capital investments in cost-effective, customer-owned distributed generation would help align utility and ratepayer interests. The utilities would earn a rate of return for prudently incurred expenditures, similar to the accounting treatment the Oregon Commission approved for investments in demand-side resources in the 1990s.[133] That mechanism put demand-side resources on par with supply-side resources by providing the same type of capitalization and depreciation over their useful life – matching over time what the utility recovered in rates with the benefits customers received.

Such accounting treatment for distributed generation would facilitate acquisition of the best combination of resources for ratepayers. It also would reduce another barrier to customer-sited generation: customers invest capital first in their core business, so they have limited ability to invest in energy projects and a high hurdle rate for doing so.

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[132] Staff's opening comments, In the Matter of an Investigation Into Regulatory Policies Affecting New Resource Development (UM 1066), Jan. 30, 2004.
[133] Order No. 89-1700, Dec. 8, 1989.

BC Hydro, for example, facilitates CHP projects at existing industrial facilities in its service area by providing much of the capital investment, and those investments are included in its rate base. The utility has selected two CHP projects to date through competitive solicitations.

First, BC Hydro contributed $18 million toward a $34.8 million, 30 MW hog-fuel generator now in operation at Weyerhaeuser's pulp mill in Kamloops, British Columbia. In exchange, the contract guarantees BC Hydro 155 GWh of load displacement for 10 years. Excess energy is sold on the wholesale market.

The other agreement is with Canadian Forest Products. Under the 15-year agreement, the company will provide all the electricity it needs for two of its mills, as well as supply power for other consumers in the area. The project is scheduled for completion by February 2005.[134] BC Hydro will contribute $49 million toward the $81 million, 48 MW generator to be installed at one of the sites.

The incentive level for these projects is about 1.5¢/kWh (Canadian), significantly lower than the 5.5¢/kWh for acquiring other new generation.[135] Another 10 projects are under consideration.[136] The utility's review of proposals includes evaluation of the host's commercial credibility and financial resources.

The utility typically provides payments in three installations: 25 percent at the beginning of construction, 50 percent once the project is fully operational, and 25 percent after measurement and verification a year later.[137] Similar to investments in facilities the utility owns, the company can earn its authorized rate of return because payments are included in rate base, amortized over the 10- to 15-year term of the contract. The customer (or any successor) must meet an annual generation target and refund a prorated portion of the payments if it switches to another electricity supplier within 10 years of the project completion date.

Similar accounting treatment could be applied in Oregon to distributed renewable resources as well as CHP facilities. Staff views CHP facilities as supply-side resources when a utility purchases the electricity, just like any other generating resource the utility may acquire. The appropriate incentive level would take into account the avoided cost of new generating resources needed to meet growing loads.

Another example of collaborative projects in the Northwest is Snohomish County PUD. The utility provided capital for a 52 MW steam-turbine generator at the Kimberly-Clark tissue plant in Everett, Wash. The utility also is responsible for some fuel costs after 10 years and some operation and maintenance costs after 15 years. The utility owns the project and receives 325,000 MWh of energy annually. It's currently selling the output to Sacramento Municipal Utility District to get a higher price than is available in the Northwest. When that contract expires, the PUD plans to use the power to offset its own needs. Kimberly-Clark provided construction management, uses the steam, and is responsible for operating and maintaining

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[134] Canadian Forest Products Ltd. press release.
[135] BC Hydro offers another option for CHP projects — buying the generation output under long-term agreements. See www.gov.bc.ca/em/.
[136] "Power Smart and Canfor Save Enough Electricity to Power 39,000 Homes," BC Hydro news release, Oct. 31, 2003.
[137] Under Oregon's "used and useful" statute (ORS 757.355), the state's regulated utilities generally would not be allowed to recover investments made before project completion if the project does not become operational. The statute prohibits utilities from charging rates derived from rate-based "construction, building, installation or real or personal property not presently used for providing utility service to the customer." (ORS 757.212(9) allows an exception for rates set under resource rate plans.) Risk mitigation measures in the utility's contract with the generating customer could guard against such contingencies, payments could be deferred until the project is operational, or the utility could use a performance-based, pay-as-you-go structure.

the facility to achieve a contracted level of generation. It continues to buy all its power from Snohomish. The plant has been in operation since 1996.[138]

[138] *Proceedings of the Combined Heat and Power Roundtable*, hosted by the Northwest Power Planning Council, June 24, 2003.

Appendix A
Technologies[139]

Gas turbines. A simple-cycle gas turbine generator consists of a combustion turbine coupled to an electric generator, generally supplied as a packaged unit. Various gaseous or liquid fuels may be used, most commonly distillate fuel oil and natural gas.

Gas turbines are a mature technology, extensively used in transportation and remote power supply applications. Gas turbine generator sets are used for cogeneration, peaking generation and emergency service. In cogeneration applications, thermal energy is extracted from the turbine exhaust. A wide range of unit sizes is available, from less than 5 MW to greater than 170 MW. Gas turbine technology is central to the aerospace industry, and aerospace applications continue to drive improvements in power density, efficiency and emissions characteristics.

The stand-alone thermal efficiency of a gas turbine generator set ranges from about 22 percent to 37 percent. The overall efficiency of cogeneration units is much greater, ranging from about 70 percent to 90 percent. The capital cost of representative, fully installed cogeneration systems ranges from about $700 to $1,900 per kW. Non-fuel operating and maintenance costs range from $0.004 to $0.01 per kWh. As unit capacity increases, electric efficiency (but not overall efficiency) typically increases and cost declines.

Nitrogen oxides (NOx), carbon monoxide (CO) and volatile organic compounds (VOC) are the principal emissions of concern for natural gas units. All hydrocarbon fuels, including biomass, produce carbon dioxide (CO_2) in proportion to the carbon-to-hydrogen ratio of the fuel. Net CO_2 production from biomass obtained from sustained harvest will be zero over time.

Small steam-electric generating technology has been in use for over a century for central-station power plants and industrial cogeneration. A steam-electric plant consists of fuel storage and processing facilities, steam generating equipment (furnace, boiler and air emission controls), a steam turbine generator, a steam condenser and boiler feedwater system, and a condenser cooling system.

Steam for cogeneration can be extracted from various points, depending on pressure and temperature requirements. High-pressure steam may be taken directly from the boiler and admitted to the steam turbine after process use. Steam at lower pressure can be extracted from one or more stages of the steam turbine. Low-pressure steam can be obtained by use of a back-pressure turbine, where the turbine is designed to exhaust at the desired steam temperature and pressure. Complex applications such as pulp and paper facilities may use process steam at several pressures.

Steam-electric cogeneration plants typically range in size from less than a megawatt to more than 100 MW. A large facility typically consists of several boilers and several smaller steam turbine generators rather than a single large machine, especially if the facility has been built up over time.

[139]CHP technology descriptions are by Jeff King, Northwest Power and Conservation Council, except where indicated. Cost and performance values for combustion turbines, reciprocating engines, microturbines and fuel cells are from National Renewable Energy Laboratory, *Gas-fired Distributed Energy Resource Technology Characterizations*, November 2003. Costs are in 2003 dollars.

Cogeneration opportunities are particularly attractive because of the low power-to-steam ratio typical of steam electric plants and the substantial increase in efficiency obtainable with cogeneration. Because steam production is separate from power generation, steam-electric plants can be designed for a wide variety of fuels including wood, bio-residues, spent pulping liquor, municipal solid waste, natural gas, fuel oil, petroleum coke and coal. Furnaces, boilers and the associated emission control systems can be designed to use these fuels singly, alternately or simultaneously.

Though steam turbine generators can exceed 99 percent availability, availability typically is a function of fuel type and boiler maintenance requirements. Industrial steam-electric cogeneration plants routinely achieve plant availabilities of 95 percent or greater.

Steam-electric equipment is durable, and 50-year-old facilities are not uncommon. The electrical generating efficiency of steam-electric technology in power-only applications ranges from 10 percent to 15 percent for small, simple plants (stand-alone bio-residue plants, for example) to 38 percent for large central-station plants using sophisticated steam cycles.

With cogeneration, the effective electrical efficiency[140] of a steam-electric cogeneration plant can range from 75 percent to 80 percent. Because of limitations on temperature rates of change due to thermal stress considerations (and also because of relatively high capital costs), steam-electric plants are best suited for baseload applications.

Air emissions from small steam-electric plants depend on the fuels used and emission controls. Emissions of potential concern include particulates, sulfur oxides (SOx), heavy metals and organic toxins (from municipal solid waste), hydrocarbons, CO and NOx. Flue gas recirculation, low excess air firing, low nitrogen fuel oil, burner modifications, water or steam injection, and selective and non-selective catalytic reduction can achieve up to a 90 percent reduction in NOx levels. Low-sulfur fuels and flue gas desulphurization can achieve a 90 percent or greater reduction in SOx emissions. Baghouses and electrostatic precipitators can control particulate and heavy metals emissions. Combustion controls and oxidation catalysts can control hydrocarbon and CO emissions. Because of their expense, catalytic controls and other complex control systems can be justified only on larger plants and plants that use fuels such as municipal solid waste.

Reciprocating engines. A reciprocating engine-generator set consists of a spark- or compression-ignition reciprocating engine coupled to an electric generator, generally supplied as a packaged unit. Various gaseous or liquid fuels may be used, most commonly distillate fuel oil and natural gas.

Reciprocating engines are a mature technology, extensively used in transportation and remote power supply applications. Reciprocating engine-generator sets are used for cogeneration, peaking generation and emergency service. In cogeneration applications, thermal energy is extracted from the exhaust, water jacket coolant, lube oil coolers and inlet air chiller, if supplied. Unit size ranges from tens of kilowatts to several megawatts. The technology is central to the automotive industry, and automotive applications drive improvements in power density, efficiency and emissions characteristics.

[140]Ratio of net power output to net fuel consumption, where net fuel consumption is total fuel consumption less the fuel used to produce the useful thermal output. The net fuel consumption is called “fuel charged to power.” The fuel used to produce useful thermal power is calculated assuming typical boiler efficiency (about 80 percent).

The stand-alone thermal efficiency of a reciprocating engine-generator set ranges from about 30 percent to 37 percent. The overall efficiency of cogeneration units is much greater, ranging from about 70 percent to 90 percent. The capital cost of representative, fully installed cogeneration systems ranges from about $900 to $1,350 per kW. Maintenance runs from $0.007 to $0.02 per kWh. NOx, CO and VOC emissions are the principal pollutants of concern for natural gas units.

Microturbines are miniature, self-contained combustion turbines ranging in size from 30 kW to 400 kW. A 30 kW unit, for example, is the size of a large refrigerator. Microturbines can run on natural gas, biogas, propane, butane, diesel and kerosene. First commercially available in 1998 and produced by just seven manufacturers, they still are relatively expensive.

Simple microturbines consist of a compressor, combustor, turbine and generator. Recuperators may be provided for additional efficiency. Most designs use single-stage turbines and a high-speed permanent magnet generator, producing variable voltage, variable frequency alternating current (AC). This power is rectified to direct current (DC) and then fed into an inverter that produces 60 Hz AC power.

The stand-alone thermal efficiency of microturbines ranges from 23 percent to 26 percent for recuperated machines. The efficiency of a microturbine making use of the waste heat it generates can reach 67 percent.

The capital cost of fully installed cogeneration systems ranges from about $1,770 to $2,640 per kW. Non-fuel operation and maintenance, typically supplied on contract, costs about $0.01 to $0.02 per kWh. NOx, CO and VOC are the principal emissions of concern for natural gas units.

Fuel cells were introduced commercially about 15 years ago. They have been slow to penetrate the electric generation marketplace because of high capital cost and the need for expensive, periodic refurbishment of the fuel cell stack.

Fuel cells work like batteries but use an external fuel source such as natural gas, methanol, propane or liquid petroleum gas. Because the fuel cell itself operates on hydrogen, non-hydrogen feedstock must be chemically reformed into hydrogen and CO_2. Hydrogen is electrochemically combined with oxygen in the fuel cell, releasing energy as DC power. For grid-connected applications and AC loads, an inverter converts DC power to AC power.

The stand-alone thermal efficiency of commercial phosphoric acid and proton exchange membrane generating units ranges from 30 percent to 36 percent. The overall efficiency of cogeneration applications (somewhat limited at present because of low waste heat temperatures) ranges from about 69 percent to 72 percent. Capital costs for fully installed cogeneration applications ranges from about $3,800 to $5,200 per kW. Non-fuel maintenance is estimated to run from $0.023 to $0.029 per kWh, including the cost of fuel cell stack replacement. Advanced technologies, including molten carbonate and solid oxide fuel cells, operate at higher temperature, are more thermally efficient and have a broader range of cogeneration applications. The stand-alone efficiency of these advanced technologies is expected to range from 43 percent to 46 percent. The efficiency of cogeneration units using advanced fuel cell technology is expected to range from 65 percent to 70 percent.

Because hydrogen reacts electrochemically with oxygen, no emissions other than water vapor are produced by the fuel cell itself. The fuel reformer produces minor amounts of NOx, CO, and VOC emissions and produces CO_2 in proportion to thermal efficiency.

Stirling engines[141] are an old technology newly applied to electrical generation. The fuel is burned in a combustion chamber that is sealed off from the working parts of the engine. The heat is then transferred into the sealed engine compartment where a working fluid (such as compressed hydrogen) is heated and expands to push down the pistons.

A Stirling engine packaged with a generator and heat recovery is currently available in a 55 kW size, with larger sizes to be released soon. The controlled combustion design allows the Stirling engine to burn a wide variety of gaseous fuels, including dirty low-energy waste gases, which can be safely burned without the need for pre-treatment.

The stand-alone thermal efficiency of Stirling engines is about 30 percent (using natural gas), increasing to 80 percent when the waste heat is used in a CHP application. The fully installed capital cost of a cogeneration system ranges from about $1,700 to $2,000 per kW. Maintenance is less than $0.01 per kWh. NOx, CO and VOC emissions are the principal emissions of concern for natural gas units.

Solar electric (photovoltaic) systems are widely available. Systems range in size from 5 kW or less for homes to several megawatts for nonresidential installations. Because of their high cost, they're used mainly in remote locations without grid connection and by customers who want to provide their own energy from a renewable source.

Solar panels are composed of photovoltaic cells, most commonly of silicon, that convert sunlight into DC power. The cells are assembled into arrays that can be mounted on rooftops or other unshaded areas. Systems can be integrated into roofing, glazing and walls. An inverter converts DC power into AC power. Batteries can store excess energy for later use, or the electric grid can serve as backup. Solar panels produce no emissions on site, have no moving parts and require little maintenance. Less expensive components, advancements in the manufacturing process, and volume sales are needed to reduce costs for widespread use.

Wind turbines have a rotor formed by two or three propeller-like blades attached to a central hub mounted on a shaft. The rotor assembly converts wind velocity to rotary motion. The rotating shaft turns a generator, producing electricity. Wind is faster and less turbulent at 100 feet or more above the ground and in areas with few obstructions such as buildings and trees.

Turbines are available from many manufacturers and range in size from less than 5 kW to new 3.6 MW machines. These packaged systems include the rotor, generator, turbine blades, and drive or coupling device placed at the top of a tall tower. Most systems have a gearbox and generator in a single unit behind the turbine blades. Some generators produce AC power already locked to the grid at 60 Hz; others have power-conditioning equipment to connect the system to the grid.

Small wind turbines today are used primarily in locations not connected to the grid. Development efforts for these stand-alone systems are focused on cheaper battery storage systems that can provide power when the turbine is not turning.

[141]Source: Robert Grott, Stirling Power, LLC, January 2005.

Wind turbines have no emissions on site, but issues such as potential bird impacts, noise, and visual "pollution" are raised with some wind farm developments.

Small hydroelectric systems[142] may be classified as in-stream, diversion, canal or conduit, pumped storage, or water current turbine:

For *in-stream* projects, a dam raises the elevation of water at the site to create operating pressure. Penstocks convey the water from the reservoir to turbines in an adjacent powerhouse. Sometimes the reservoir may impound sufficient water to permit regulation of streamflow so power can be generated as needed. Habitat requirements and other uses of the stream also determine the extent of regulation. Projects without significant storage ("run-of-river" projects) generate power as streamflows permit.

In a *diversion* project, water is diverted from the stream by a diversion structure (generally a low dam or weir) and conveyed to a downstream powerhouse by canals and conduits. The distance between the diversion structure and the powerhouse may be very short, as in a diversion around a natural waterfall, or may be many miles. The water pressure at the turbines is determined by the difference in elevation between the diversion structure and the powerhouse. Sometimes the diversion structure is a high dam that may provide additional operating head or water storage. Flows are maintained in the bypassed natural channel to sustain habitat or to support non-power uses of the stream.

A *canal or conduit* project uses operating head created by water conveyance structures installed primarily for non-power purposes. These include irrigation and municipal water supply systems.

Pumped storage projects are used to store energy for times of greater need. A pumped storage project includes upper and lower reservoirs. Water is pumped by means of reversible pump-turbines from the lower to the upper reservoir at times of surplus electricity production. Water is released from the upper reservoir to the lower reservoir to generate power at times of greater demand. Pumped storage hydropower is generally designed to cycle on a daily basis.

A *water current turbine* converts the kinetic energy of flowing water into electricity. No operating head (pressure) is developed. Because of the low energy content of moving water, current turbines are physically large in proportion to the amount of electric energy produced.

Measures to improve the efficiency of existing hydropower projects take many forms, including turbine runners (blade and hub assembly) of improved design and materials, electronic turbine governors, low-friction generator cooling systems, improved generator windings, solid-state generator exciters, high-efficiency transformers, reduced bypass water losses, installation of generation on unavoidable bypass water systems, such as those for fish attraction flows, improved station motor, pumping efficiencies and increased turbine operating head through reservoir elevation. Generating unit dispatch and project coordination through integrated system-wide operational control may offer an attractive opportunity to increase overall hydropower system efficiency.

Wave energy.[143] Waves are produced by the action of wind blowing over water. The wave energy of the mid- and North Pacific coasts is the best of any coastal area of the United States,

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[142]Descriptions are from the Northwest Power Planning Council's Fourth Power Plan, Appendix F, 1996.
[143]Northwest Power and Conservation Council, Fifth Power Plan, pre-publication draft, January 2005.

with estimated average wave power at near-shore locations ranging from 6 kW to 9 kW per meter of wave crest. Offshore, the estimated power is 37 kW to 38 kW per meter of wave crest.

The theoretical wave power potential of the Washington and Oregon coast is about 3,400 MW to 5,100 MW for near-shore sites and 21,000 MW for offshore sites. Wave power devices are expected to have an efficiency of at least 12 percent, suggesting a technical potential of 400 MW to 2,500 MW. Only a portion of this potential is likely to be available because of navigational, aesthetic or ecological concerns and the need to maintain clearance between wave power units. Wave power in the Northwest is winter peaking with high seasonal variation.

Wave energy technology is in its infancy. A diversity of conceptual designs has been proposed and several prototypes and demonstration projects have been constructed.

Appendix B
PURPA Facilities Selling to Oregon Investor-Owned Utilities[144]

Idaho Power

Project Name	Resource Type	Project Nameplate	Date Signed	Operation Date	Termination Date
Owhyee Dam	Hydro	5 MW	April 1984	May 1985	Aug. 2015
Mitchell Butte	Hydro	2.1 MW	May 1985	May 1989	Aug. 2024
Tunnel #1	Hydro	7 MW	May 1985	June 1993	May 2028

Portland General Electric

Resource Type	Plant Capacity	Date Signed	Termination Date
Municipal solid waste	13,100 kW	09/14/1984	06/30/2014
Hydro	170 kW	08/28/1983	05/31/2014
Hydro	500 kW	11/24/1926	Evergreen
Hydro	95 kW	11/01/1983	10/31/2003
Hydro (water wheel)	50 hp	02/21/1984	10/31/2003
Hydro	100 kW	11/01/1983	10/31/2003
Hydro	10 kW	11/01/1983	10/31/2003
Hydro	100 kW	05/17/1984	10/31/2003
Hydro	100 kW	11/01/1983	10/31/2003

[144]Information provided by the utilities in Oregon PUC Docket No. UM 1129, March-April 2004.

PacifiCorp

Resource	Project	Size (kW)	Initial Contract Effective Date	Date of Initial Power Delivery	Termination Date
Hydro	Lloyd Fery	40	January 1, 1984	Prior to 1985	31-Dec-04
Hydro	Mountain Energy	50	November 3, 1982	January 1986	31-Dec-04
Wind	Stephen Hurn	65	July 28, 2003	August 2003	20-Aug-08
Hydro	Curtiss Livestock	75	January 1, 1984	Prior to 1985	31-Dec-05
Hydro	Toni Rousch	75	January 1, 1984	Prior to 1985	31-Dec-08
Hydro	Boston Power Co./Thompson's Mill	100	August 19, 1983	June 1986	31-Dec-06
Hydro	Santiam	160	September 30, 1983	October 1985	31-Dec-19
Hydro	Odell Creek	225	September 27, 1983	January 1986	31-Dec-10
Hydro	Nichols Gap	720	September 28, 1983	March 1987	31-Dec-21
Hydro	Lacomb Irrigation	962	October 28, 1982	July 1987	31-Dec-22
Hydro	North Fork Sprague	1,250	May 20, 1983	September 1989	31-Dec-23
Hydro	Galesville Dam	1,800	September 1, 1982	February 1987	31-Dec-21
Hydro	Farmers Irrigation District	3,150	June 29, 1983	October 1985	31-Dec-10
Hydro	Middle Fork Irrigation	3,300	September 29, 1983	March 1986	31-Dec-05
Hydro	Frontier Technology/Falls Creek	4,100	September 30,1983	December 1984	31-Dec-19
Hydro	Opal Springs	5,000	November 15, 1982	January 1985	31-Dec-20
Hydro	Central Oregon Irrigation District-Siphon Project	6,000	April 19, 1983	September 1989	31-Dec-20
Biomass	Co-Gen II	8,300	September 29,1983	October 1987	31-Dec-06
Biomass	Biomass One	25,000	September 3, 1982	December 1985	31-Dec-11

Appendix C
Oregon Incentives

State tax credits and low-interest loans are available for high-efficiency CHP and renewable resource projects.

Businesses can get a 35-percent tax credit on eligible project costs. For CHP, the tax credit generally is only for the heat recovery portion of the project. To encourage more efficient CHP applications, the Oregon Department of Energy currently offers research and demonstration status for projects less than 25 MW that have a heat rate of 6,120 Btu/kWh or better and meet model standards for emissions. Projects that meet these criteria are eligible for a 35-percent tax credit on the cost of the *entire* CHP system.

The state also provides sizable tax credits for residents for renewable energy systems and fuel cells.

In addition, the State Energy Loan Program provides low-interest, long-term loans for CHP and renewable resource projects for individuals, businesses, schools, governments and other institutions.

PGE and PacifiCorp customers, and residential and commercial customers of NW Natural, are eligible for incentives for distributed generation projects through public purpose funds administered by the Energy Trust of Oregon. Renewable resource generating projects are eligible for funds through the Energy Trust's solar electric and wind programs, or through its open solicitation process. For cost-effective, high-efficiency CHP systems, the Energy Trust provides an incentive to increase the efficiency of waste heat utilization. For small CHP systems, the Energy Trust also may provide an incentive for the generator. The Energy Trust is reviewing its CHP policy and may develop additional incentives.

PGE's and PacifiCorp's largest customers can spend a portion of their public purpose charge on qualifying renewable resource and conservation projects, including distributed generation, at their own facilities. The Oregon Department of Energy oversees the administration of funds for these projects.

NW Natural is offering incentives for natural gas-fired CHP equipment up to 25 MW. Projects that are installed between Jan. 1, 2005, and Dec. 31, 2009, and meet or exceed the efficiency requirements for the state Business Energy Tax Credit, are eligible for the incentives:

- Firm service customers are eligible for a credit of 2.7 cents per therm for gas purchased for the CHP equipment.
- Interruptible customers can make use of billing services that facilitate participation in the CHP project by third parties, who can take advantage of depreciation and tax credit benefits. CHP gas use will be billed to the third party as though it were added load on the customer's primary rate schedule. Thus, the CHP gas use will qualify for the lower, tail-block rate.

Appendix D
Perspectives on Distributed Generation Barriers

In 2001, PUC staff surveyed owners of Oregon cogeneration facilities, and businesses that were planning cogeneration or small power projects, about the barriers they faced. They cited:
- Low electricity prices (compared to the cost of installing and operating their own facility)
- Lack of timely cooperation from the utility
- Unreasonable interconnection studies

In 2003, staff met individually with large customers and developers to discuss a host of issues, including distributed generation. They raised these barriers:
- Project economics, considering interconnection costs, electricity rates and natural gas prices
- Lack of thermal load for using waste heat
- The utilities' general aversion to distributed generation and discriminatory treatment compared with how they treat their own generating facilities
- Requirements for redundant safety equipment for interconnection
- Expensive interconnection studies with too long a timeframe
- Lack of timely updates of utility avoided costs
- Onerous demand charges for standby service
- No credits for reducing congestion on distribution and transmission systems
- Inability to sell power without the utility requiring expensive system impact studies and substation upgrades, even when the system is sized not to exceed the maximum customer demand
- No provisions for utilities to buy ancillary services from the customer-generator
- No published rates for wheeling power over the distribution system
- Inability to obtain sufficient firm transmission rights for selling power
- Cumbersome contract negotiations with the utility for power
- Utility discretion to discount the avoided costs it pays under negotiated contracts (for generators larger than 1 MW)
- No incentive for the utility to buy power from distributed generators
- Delays and expenses related to emissions and land use permits
- Financing
- Assigning risk and responsibilities for power purchase agreements with marketers

The U.S. Combined Heat and Power Association, representing the CHP industry, cites the following barriers:[145]
- Lack of consistent standards for utility interconnection or streamlined processes, especially for smaller systems
- Unfair utility rates for standby service and back-up power (and exit fees in some areas)
- Emissions permitting that does not credit combined heat and power systems based on their greater efficiency or for displacing emissions from power plants
- Inappropriate tax treatment (slower depreciation than the same machine being used for other purposes because CHP systems are treated as "utility" equipment)

The utilities offer another perspective. PacifiCorp believes the primary barriers to distributed generation are economics and interconnection issues.[146] In addition to low power costs

[145]U.S. Combined Heat and Power Association, http://uschpa.admgt.com/chpissues.htm.
[146]PacifiCorp's response to OPUC data request, July 1, 2002.

throughout much of the 1990s, PGE cites long project lead times as a barrier to distributed generation. PGE also has recommended decoupling of distribution sales and revenues to reduce barriers to distributed resource development.[147]

NW Natural sees four main barriers to small combined heat and power systems:[148]

- Project economics, including up-front capital costs, maintenance costs, and natural gas and electricity rates, including standby rates
- Electricity generation is a non-core activity for most customers. Capital projects tend to compete from the same pool in the budget process, and core-related activities tend to get higher priority.
- Mechanical interconnection and tie-in to building systems can be difficult.
- Nascent technology. Equipment efficiency needs to be improved, and equipment selection for small systems is limited.[149]

[147] PGE's response to OPUC data request, July 3, 2002, and Direct Testimony of Randy Dahlgren and Sara Cardwell, UE-126, Oct. 11, 2001.
[148] Chris Gelati, NW Natural, March 2004.
[149] Staff notes that barriers inherent with new technology also include lack of awareness of the benefits and lack of confidence that it will work as promised, few installations where customers can see how the technology might work for them, and few vendors offering packaged services for installation, operation, maintenance and warranties.

Table 1. Non-Hydro Distributed Generation Projects in Oregon
(4 kW or larger)

Project*	Primary fuel	Nameplate capacity (kW): Plants in service	Nameplate capacity (kW): Plants idle	Location	Owner	Thermal Host (Cogeneration)	Thermal Load (Cogeneration)
Alan David LLC	Biomass		40	Beaver	Alan David LLC	—	—
Alternative Energy Consortium	Solar	25		Eugene	Alternative Energy Consortium	—	—
Amalgamated Sugar 1-3	Coal		14,000	Nyssa	Amalgamated Sugar Co.	Amalgamated Sugar Company	Food processing
Apeasay Orchard	Wind	22		Hood River	Apeasay Orchard	—	—
Ashland Solar Project	Photovoltaic	10		Ashland	City of Ashland	—	—
Biomass One	Wood residue	30,000		White City	Biomass One, L.P.	Biomass One, L.P.	Lumber and wood products
Blue Mountain Forest Products	Wood residue		3,500	Pendleton	Blue Mountain Forest Products	Blue Mountain Forest Products	Lumber and wood products
Boise Cascade - Medford	Wood residue	6,800		Medford	Boise Cascade	Boise Cascade - Medford	Lumber and wood products
Brewery Blocks	Solar	22		Portland	Gerding/Edlen Development	—	—
Burrill Lumber	Natural gas		1,500	White City	Eugene F. Burrill Lumber	Eugene F. Burrill Lumber	Lumber and wood products
Calapooia Crossing	Solar	4		Sutherlin	Umpqua Community Development Corp.	—	—
Cal-Gon Farms	Manure	100		Salem	PGE	—	—
City of Portland Fire Station 16	Solar	6		Portland	City of Portland	—	—
City of Portland Fire Station 25	Solar	6		Portland	City of Portland	—	—
Co-Gen II	Wood residue	7,500		Riddle	D.R. Johnson Lumber Company	D.R. Johnson Lumber Company	Lumber and wood products
Columbia Boulevard fuel cell	Wastewater gas	200		Portland	City of Portland	Columbia Blvd. Wastewater Plant	Wastewater treatment
Columbia Boulevard microturbines	Wastewater gas	120		Portland	City of Portland	Columbia Blvd. Wastewater Plant	Wastewater treatment
Combine Hills	Wind	41,000		Milton-Freewater	Eurus Combine Hills I LLC	—	—
Corvallis Wastewater Plant	Wastewater gas	55		Corvallis	Quantum Engineering and Development	Corvallis Wastewater Plant	Wastewater treatment
Covanta Marion	Municipal solid waste	13,100		Brooks	Covanta Marion	—	—
Crown Pacific	Wood residue	1,500		Gilchrist	Crown Pacific Partners, LP	Crown Pacific Partners, LP	Lumber and wood products
Durham Wastewater Plant	Wastewater gas	250		Tigard	Clean Water Services	Clean Water Services	Wastewater treatment
Eugene/Springfield Wastewater Plant	Wastewater gas	800		Springfield	Eugene/Springfield Metro	Eugene/Springfield Metro WWTP	Wastewater treatment
EWEB fuel cells (two 5-kW units)	Methanol	10		EWEB service area	EWEB	EWEB	Water heating
Georgia-Pacific - Wauna	Spent pulping liquor	36,000		Wauna	Clatskanie Co. PUD, EWEB	Georgia-Pacific (Wauna)	Kraft, groundwood pulp, newsprint, towelling, tissue/paper mills
Gresham Wastewater Plant	Wastewater gas	200		Gresham	City of Gresham	Gresham Wastewater Plant	Wastewater treatment
Harkins House	Natural gas	7		Hillsboro	Washington County	Harkins House	Domestic hot water
Heppner Power Plant	Wood residue		10,000	Boardman	Port of Morrow	—	—
Hurn wind project	Wind	65		Madras	Stephen Hurn	—	—
Kellogg Creek Wastewater Plant	Wastewater gas	250		Milwaukie	Clackamas Co. Serv. Dist. #1	Clackamas Co. Serv. Dist. #1	Wastewater treatment
Kettle Foods	Solar	114		Salem	Kettle Foods	—	—
Lebanite	Wood residue		2,000	Lebanon	Georgia-Pacific Corp.	Georgia Pacific Hardboard Plant	Defibrated wood and board mills
Lewis and Clark College	Natural gas	30		Portland	Lewis and Clark College	Lewis and Clark College	Swimming pool and domestic hot water
Market Street	Natural gas	30		Portland	200 Market Street Partners	200 Market Building	Absorption cooling (summer); boiler preheat (winter)
Medford Wastewater Plant	Wastewater gas	700		Medford	City of Medford	Medford Wastewater Plant	Wastewater treatment
Oregon State Capitol	Solar	8		Salem	State of Oregon	—	—
Pepsi Cola Bottling (3 buildings)	Solar	172		Klamath Falls/Lakeview	Pepsi Cola Bottling of Klamath Falls	—	—
PGE dispatchable standby generation	Diesel	17,000		PGE service area	Various	—	—
PGE Earth Advantage fuel cell	Methanol	5		Portland	PGE	PGE Earth Advantage Center	Water heating
Port of Tillamook Bay MEAD project	Manure	400		Tillamook	Port of Tillamook Bay	—	—
Prairie Wood Products (Co-Gen I)	Wood residue	7,500		Prairie City	D.R. Johnson Lumber Company	Prairie Wood Products, Inc.	Lumber and wood products
Rock Creek Wastewater Plant	Wastewater gas	1,000		Hillsboro	Clean Water Services	Rock Creek Wastewater Plant	Wastewater treatment
Roseburg Forest Products - Dillard	Wood residue	45,000		Dillard	Roseburg Forest Products	Roseburg Forest Products - Dillard	Lumber and wood products
SierraPine Medite	Natural gas	6,000		Medford	SierraPine Medite	SierraPine Medite	Pulp and paper (fiberboard production)
SP Newsprint**	Natural gas	135,000		Newberg	SP Newsprint	SP Newsprint	Paper
Tamarack Wellness Center	Solar	24		Eugene	Tamarack Wellness Center	—	—
Tri-City Service District	Wastewater gas	250		Oregon City	Tri-City Service District	Tri-City Service District	Wastewater treatment
University of Oregon Business Center	Solar	35		Eugene	University of Oregon	—	—
Wah Chang	Natural gas		14,000	Albany	Wah Chang	Wah Chang	Steam to metals processing
Warm Springs Forest Products	Wood residue	3,000	6,000	Warm Springs	Warm Springs Forest Products	Warm Springs Forest Products	Lumber and wood products
Weyerhaeuser - Springfield 1	Spent pulping liquor		7,500	Springfield	Weyerhaeuser	Weyerhaeuser	Kraft, pulping and linerboard mills
Weyerhaeuser - Springfield 2	Spent pulping liquor		5,000	Springfield	Weyerhaeuser	Weyerhaeuser	Kraft, pulping and linerboard mills
Weyerhaeuser - Springfield 3	Spent pulping liquor	12,500		Springfield	Weyerhaeuser	Weyerhaeuser	Kraft, pulping and linerboard mills
Weyerhaeuser - Springfield 4	Spent pulping liquor	40,000		Springfield	Eugene Water & Electric Board	Weyerhaeuser	Kraft, pulping and linerboard mills
Weyerhaeuser - Albany #1 CT	Natural gas	47,700		Millersburg	Weyerhaeuser	Weyerhaeuser	Kraft, pulping and containerboard mills
Weyerhaeuser - Albany	Spent pulping liquor	45,000		Millersburg	Weyerhaeuser	Weyerhaeuser	Kraft, pulping and containerboard mills
Willow Lake Wastewater Plant	Wastewater gas	800		Salem	City of Salem	Willow Lake Wastewater Plant	Wastewater treatment
Total in service (MW)		**500.3**					
CHP in service (MW)		**428.2**					
Total idle (MW)			**63.5**				
Grand total (MW)		**563.9**					

Sources: Northwest Power and Conservation Council, Oregon Department of Energy, project owners, utilities and distributed generation companies
*Not listed are nondispatchable backup generators, uninterruptible power systems, hydroelectric systems that may be considered distributed generation, landfill gas systems, and more than 250 home solar electric systems and small wind systems installed with state incentives.
**About 40 MW of generation is from residual fuel (bark).