

WILLAMETTE VALLEY BIOENERGY PRODUCTION FACILITY BUSINESS PLAN

APPENDIX TO FINAL REPORT

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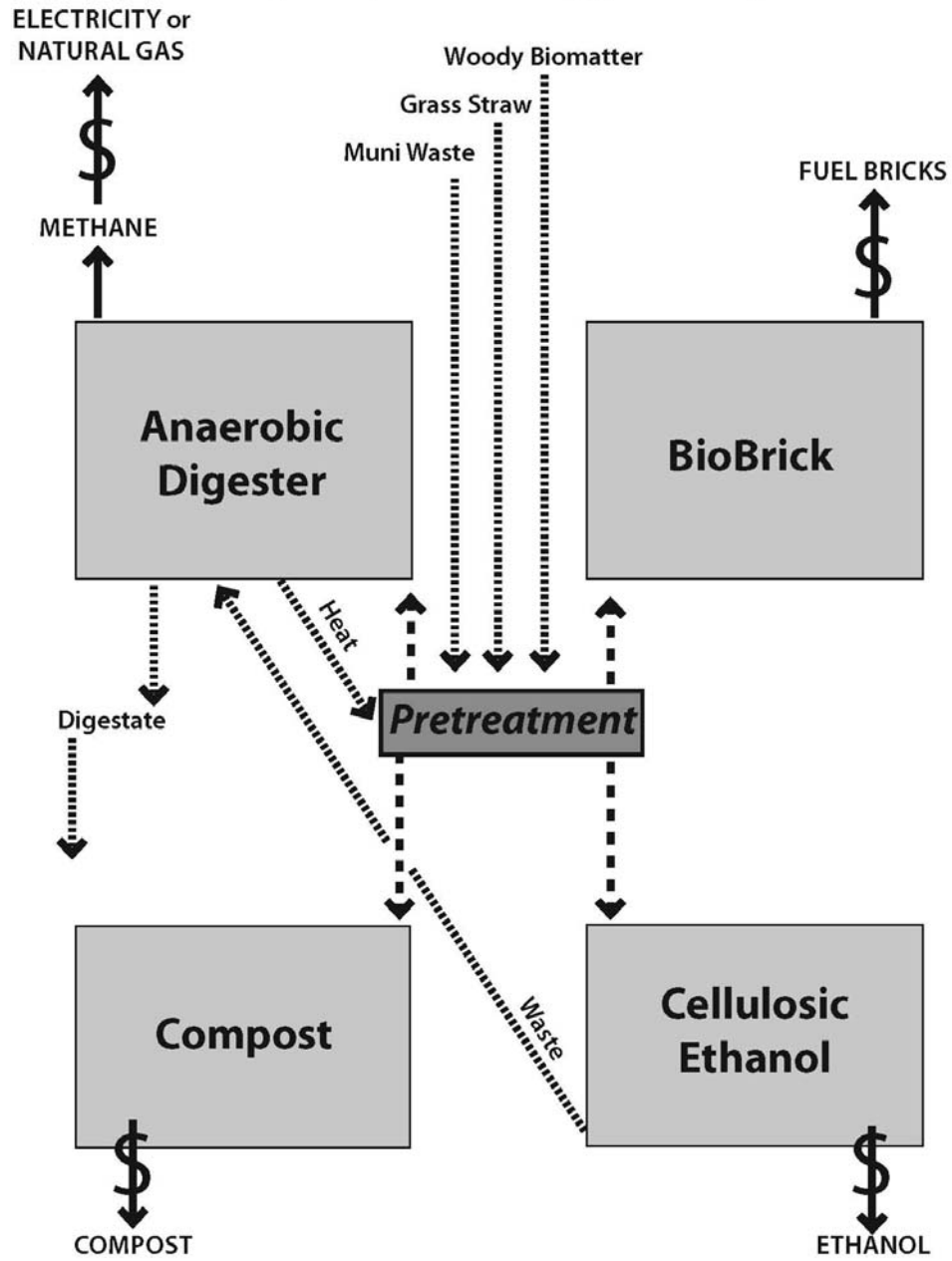
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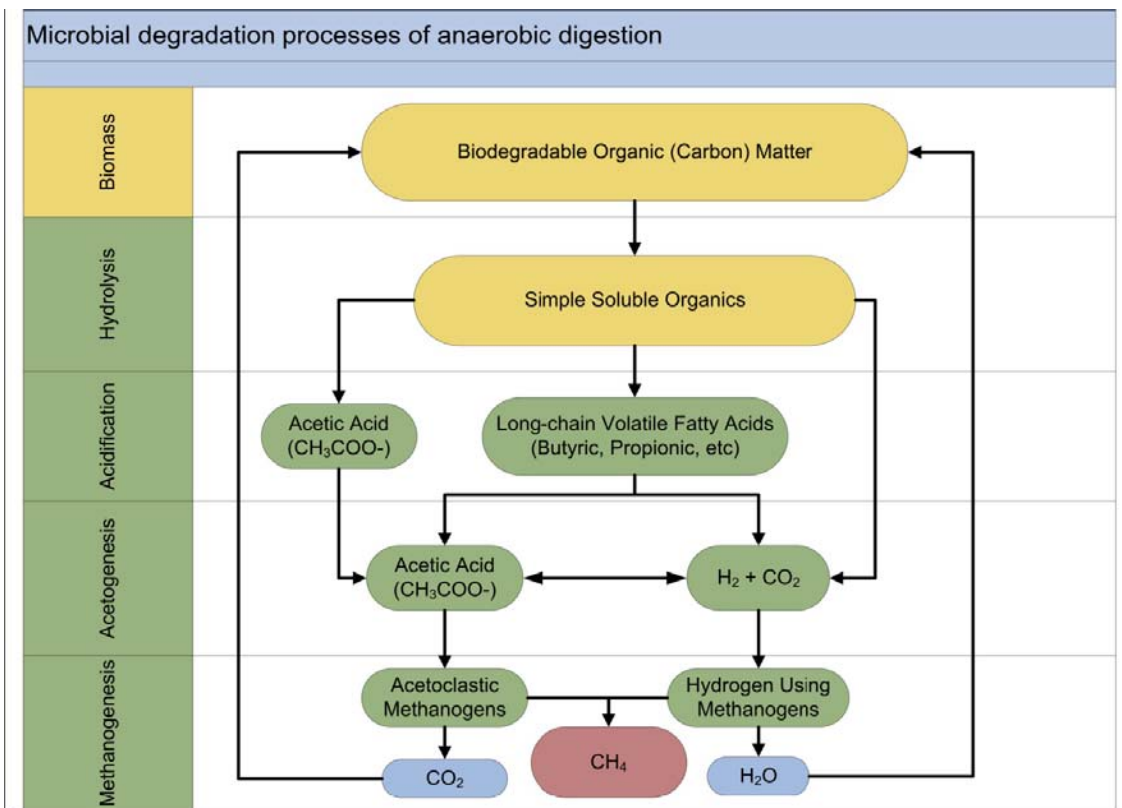
Source: Lane Council of Governments

Technology Process Overview

Overview of Anaerobic Digestion Technology

Biogas is a renewable natural gas replacement, produced through the controlled decomposition of organic matter in a process referred to as anaerobic digestion (AD). Biogas production is the result of a complex sequential biological process, in which the substrate is continuously broken down.

The degradable fraction of a feedstock is called volatile solids (VS). Hydrolytic enzymes reduce complex organic polymers to monomers and oligomers; acidogenic bacteria utilize these simpler compounds to form organic (volatile fatty) acids; acetogenic bacteria then convert the long chain acids to acetic acid; finally, methanogens create methane (CH₄), H₂O and CO₂ from precursors formed in the previous steps (Figure 1).



Source: EC Oregon

Figure 1. Microbial degradation processes of anaerobic digestion

Anaerobic digestion is wide spread throughout the European Union (EU) and Asia but is under represented in the United States primarily due to historically low energy costs. The technology can be instrumental in providing renewable energy to industry and the agricultural community while closing the loop on the nutrient cycle (Figure 2). Digester systems, or "biogas plants" as they are referred to in the EU, are applicable to a wide range of situations, but synergy is most realized at facilities that have access to sizable

organic feedstock at little to no cost, require electricity and heat, that can be provided by a biogas-powered combined heat and power unit (CHP) or a direct use of biogas (such as boilers) and can utilize/market the digester effluent as compost and liquid fertilizer.

Traditionally, the primary use of anaerobic digestion has been to sanitize waste materials associated with livestock operations, industrial facilities or municipal waste water treatment plants.

As the utilization of bio-methane as a renewable fuel has increased, more research and pilot projects have begun to utilize various waste streams, known as feedstocks, specifically for energy production.

The use of AD for sewage sludge stabilization is well established, as is its use as a treatment step for industrial wastewater. Over 35 types of industries have been identified as having wastewaters amenable to AD treatment, including processors of beverages, chemicals, food, meat, milk, pulp and paper, and pharmaceuticals. The use of agricultural residue, as well as purpose grown energy crops, is rapidly increasing at European biogas plants. A recent application of AD is to the organic fraction of municipal solid waste streams; waste managers have found that AD provides environmental benefits allowing waste disposal facilities to meet increasingly stringent regulation. A partial summary of biogas facilities illustrates the widespread use of the technology (Table 1).

Co-digestion refers to the process of using multiple feedstocks in an AD system for the purpose of increasing the biogas yields and optimizing the treatment of the waste. Importing outside feedstocks can allow industrial users to increase their renewable energy generation beyond facility demands, thereby producing surplus electrical power or pipeline-grade methane for supply to the grid and/or surplus heat energy to supply co-located facilities. For agricultural users, certain energy crops can be grown and stored for the expressed purpose of co-digestion, buffering seasonal processing feedstocks while adding value to rotational crops.

Anaerobic Digesting Worldwide
(A limited sample)

Region/Nation	Feedstock Type	Number of Facilities	Source	Data Year
Nepal	Household/Farm Waste	140,000	(a)	2006
China	Household Waste	15 million	(a)	2004
China	Household/Farm Waste	27 million	(a)	2010
India	Household/Farm Waste	3.67 million	(a)	2006
Bangladesh	Household/Farm Waste	24,000	(a)	2004
Bangladesh	Household/Farm Waste	36,450	(a)	2006
Canada	Farm Waste	17	(b)	2009
United States	Livestock Manure	1,700	(c)	2010
Europe*	Multiple Sources**	217	(d)	2008

*Austria, Belgium, Denmark, Estonia, Finland, France, Germany, Italy, Netherlands, Spain, Sweden, Switzerland, and UK.

**Multiple Sources including: Biowaste, Manure, Paper, MSW, OIW, and Grey Waste.

Sources:

(a) UN Economic and Social Commission for Asia and the Pacific. 2006

(b) Ontario Ministry of Agriculture Food and Rural Affairs, 2009

(c) DOE EERE - U.S. Department of Energy Efficiency and Renewable Energy, 2010

(d) International Energy Agency, Bioenergy Task Force, EUROPEON UNION PLANT LIST 2008

Effluent from the anaerobic digestion process, called digestate, includes a wet fraction that can be utilized as a marketable agricultural fertilizer and a solid fraction which makes an ideal compost component. By coupling anaerobic digestion and fertilizer/compost production, the feedstock is optimally utilized and provides excellent soil amendments while reducing the amount of material in local landfills and wastewater treatment plants. Anaerobic digestate could become an important source of certified organic fertilizer as petroleum-based fertilizer costs rise and conventional acreage is converted to organic.

There are myriad reasons for the increased interest in biogas, foremost being energy efficiency. Based on life cycle analyses, biomethane has 2-3 times more energy yield from an acre of land than other biofuels (Figure 3). It is also has versatility as fuel for electricity, heat or vehicle fuel and can be transported efficiently via natural gas pipeline to optimal end-users. Biomethane can be created from numerous high-yielding energy crops, from multiple harvests and – perhaps most significantly – from a wide variety of waste streams. In Germany, the world leader in renewable energy production, biogas plants produced over 5.4 billion kWh in 2006. There are over 3800 biogas plants in Germany alone with electrical production of 15,000 MWh, including large scale facilities that produce over 20MW.

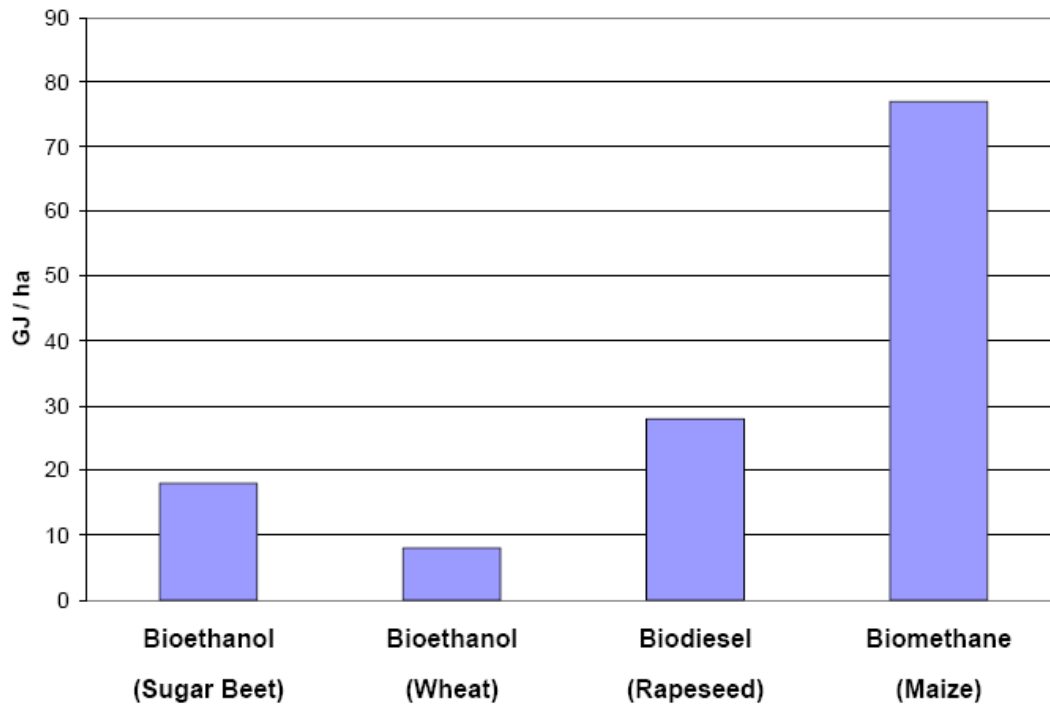


Figure 2. Net energy output of various biofuels (DeBaere, 2007)

Co-digestion

Co-digestion refers to the process of utilizing multiple waste streams in an AD system for the purpose of increasing the biogas yields and optimizing the degradation of the waste. Co-digestion is typically synergistic: a combination of feedstocks results in higher methane yield than if the feedstocks were digested separately. This effect is thought to be due to improved micro-nutrient availability and optimized rheological qualities for multiple sources. All anaerobic digestion feedstocks are not equal in terms of methane potential (Figure 4). For example, 3-6% glycerin added to an energy crop/manure feed regime has been shown to increase methane production by approximately 33%.

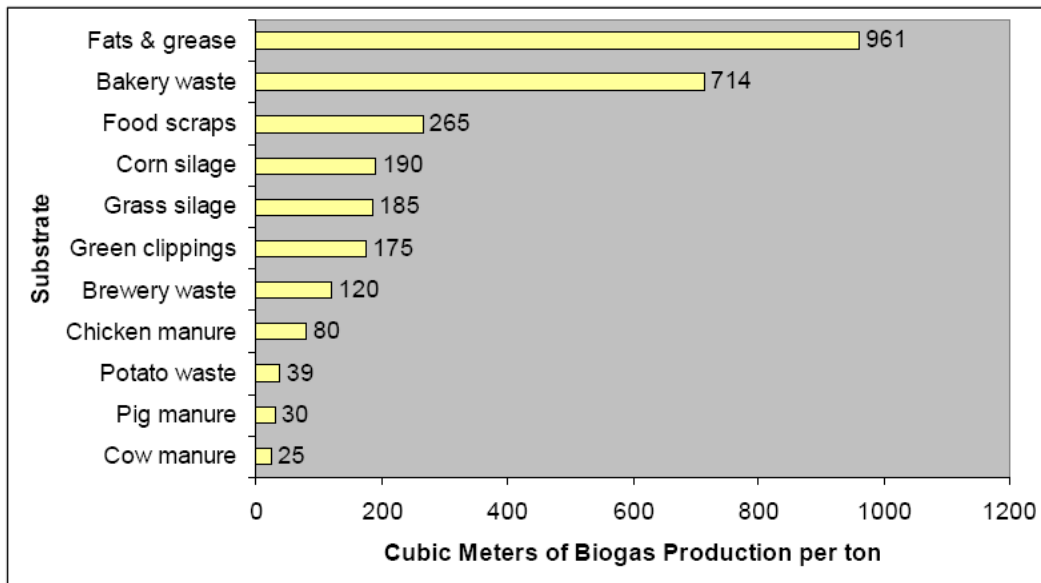


Figure 3. Cubic meters of biogas production per ton of substrate (from Kramer, 2008)

The bacterial colony utilized in anaerobic digestion requires a wet environment. Similarly, a single feedstock rarely contains the proper balance of micro nutrients for optimal methane production. Multiple feedstock co-digestion is often the best way to ensure a balanced biological system. The frequency distribution of anaerobic digester systems utilizing multiple feedstocks (i.e. substrate) in the EU is presented in Figure 5.

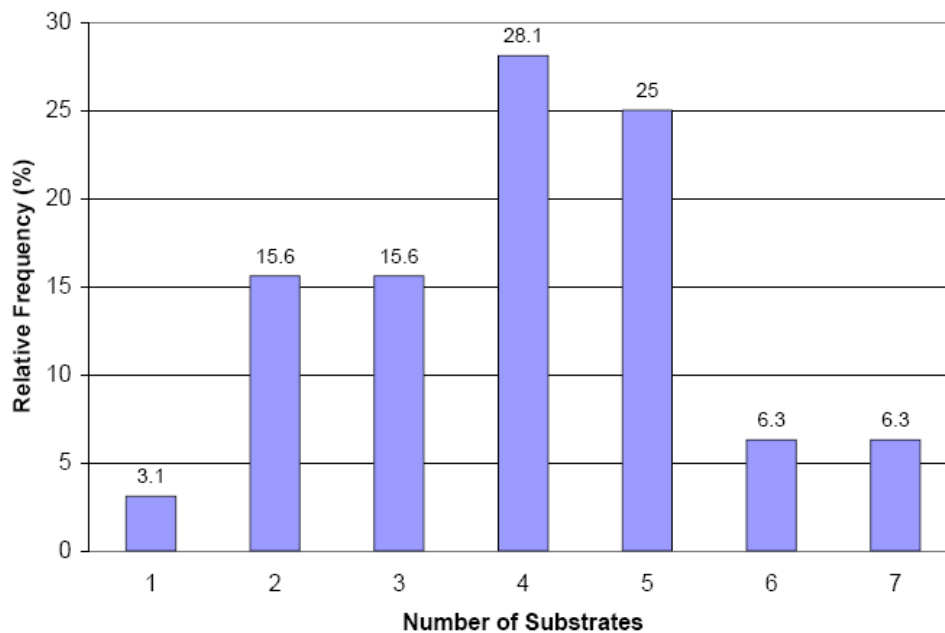


Figure 4. Frequency distribution of “number of substrates” for anaerobic digester facilities built in EU, 2003 - 2005 (from Hopfner-Sixt, et al. 2005)

Technology Process

In a typical dairy digester installation, everything from collecting the manure to storing the solids and liquids coming out of the digesters is done without human interaction. Just half an hour a day is required to monitor the system. Biogas Energy digesters work day in and day out so farmers can concentrate on their core business.

Substrate feed

Manure is automatically pumped directly from a receiving or thickening tank into the digesters. To generate significantly more methane than manure alone, Biogas Energy digesters accept multiple substrates, from grease to corn silage to food waste. Manure has low energy content since cows have already digested the substrate, so adding high-energy value materials produces more methane. The complete & continuous mix action within the digesters sustains an optimal environment for bacteria to digest these high-energy materials.

A pump or screw conveyor feeds the raw materials into the digesters, and existing equipment is incorporated into the facility wherever possible. Automated feeding regulates input of material to ensure optimal digestion and reduces labor required for operating the system.

The digesters

A biogas facility typically has two or more cylindrical digesters with heating pipes integrated into the walls and floor. The walls are insulated and clad with weatherproof panels. The digesters are built above ground to reduce costs and facilitate maintenance, and their cylindrical shape ensures maximum engineering and thermal soundness.

Redundancy

With two or more digesters, several crucial benefits are achieved over a single tank design. If one digester is taken offline, the other continues to operate without interruption, so the farmer is not stuck with tons of manure to deal with. Ease of expansion: To increase facility capacity by any amount, simply add a digester at any time. Quick disaster prevention and recovery: If the bacteria in one digester get sick, healthy bugs from the other tanks can be added to bring it back online quickly.

Roofing system

Biogas Energy digesters are covered with double-membraned roofs that protect from the elements, allowing easy access to the digester's contents, and contain built-in gas storage. The roof's outer membrane has withstood harsh Northern winter climates for over a decade, while the inner membrane expands and contracts as a built-in gas holder for up to 10 hours of biogas production. Between the two membranes an air pump maintains pressure to give the outer membrane its stability while applying pressure to the gas storage.

By including gas storage as standard equipment, we reduce costs and gain considerable energy production efficiencies. For example, when the CHP unit is turned off for routine maintenance, the gas can be stored until operations continue. That way, our customers don't lose a cubic foot of methane to flaring. Every minute of gas flared is money lost, so gas storage adds directly to the bottom line.

If an issue arises within the digester, the roof can be unhitched and folded back to give instant access; impossible with a steel or concrete roof. This ease of access means repairs take a few minutes, not days, so downtime is reduced to a minimum.

With the ability to store gas while also enabling quick, easy access to the insides of the digesters, the roofing system saves considerable money in the long run.

Mixing devices

The contents of each tank are mixed with 2-4 submerged agitators to foster optimal bacterial proliferation and ensure steady, reliable methane production. The agitators adjust automatically or manually and ensure a complete, pervasive mix of substrate for an optimized climate for bacterial proliferation and pathogen treatment. Agitators have an expected lifetime of 8-10 years since they only run for 5-20 minutes each hour. Should an agitator require repair or replacement, it's simply matter of folding back the roof, lifting out the unit, and replacing it in minutes. Unlike digesters with concrete roofs or central mixing devices, there is minimal downtime and no loss of operations.

Desulphurization

High levels of hydrogen sulphide reaching the Combined Heat and Power unit cause severe degradation of the machinery and lead to recurring mechanical failures. Biogas Energy builds proprietary desulphurization equipment into the digesters that can reduce hydrogen sulphide levels to 250PPM or lower, depending on substrates, and can add additional equipment as needed. Compared to other digester vendors that produce biogas with more than 2000 PPM H₂S, Biogas Energy's desulphurization is well within the acceptable range for CHP units. For those facilities that require further reduction of sulphur content, additional desulphurization treatment is available.

Combined heat and power unit

After desulphurization, the biogas is converted into electrical and thermal energy in a combined heat and power (CHP) unit, also called a cogeneration unit. All of the facility's equipment, including the digester heating, runs on power generated by the CHP unit. Surplus electricity (typically 95% of the amount generated) is fed into the public grid and sold to the local power utility.

Surplus heat can be used to heat homes or buildings as well as for agricultural and industrial processes that require significant heat.

Biogas Energy's digesters are not just energy self-sufficient; they produce ample surplus electricity and heat to generate recurring revenue as a renewable, clean, domestic energy source.

Digester Gas Generator Set Basis Specifications

The following are basic specifications for a digester gas 2 Megawatt (MW) engine generator system. The gas engine, generator, systems controls, switching gear specifications and performance characteristics are the basis for determining fuel and operating requirements, net electric energy production and thermal energy available for recovery.

Biogas reciprocating engine generators are essentially diesel compression engines that have been re-engineered into machines that can handle larger volumes of gaseous fuels in continuous duty. They have been modified to accept higher levels of CO₂ and contaminants in the incoming air stream (versus the uniform characteristics of commercially supplied natural gas). The latest generation gas engines incorporate technologies developed with the U.S. Department of Energy Advanced Reciprocating Engine Systems (ARES) program, and have been commercially available since 2002. These lean-burn, electronically controlled units deliver between 1 to 6 MW of capacity and are capable of up to 43 percent mechanical efficiency. The lean mixture combustion system manages fluctuations in the methane content of gases being combusted and minimizes NO_x emissions.

This class of equipment is specifically designed to address varying gas conditions and contamination levels while meeting national air quality standards. They can produce nitrogen oxide (NO_x) emissions as low as 0.5 g/bhp-hr, without exhaust catalyst treatment. Oxidation catalysts for gas stationary engines lower emissions by converting CO, hydrocarbons and aldehydes into carbon dioxide and water. This can reduce CO by 93 percent in gas engines and decrease hydrocarbons by more than 40 percent. Chemical reactions in the exhaust do not change or consume the catalyst material, reducing maintenance requirements.

Gas fuel requirements for various manufactures engine generators are relatively consistent at each power output capacity. An anaerobic digester (AD) using Oregon Willamette Valley feedstocks can produce between 2 and 3 million British Thermal Units of methane (CH₄) per ton. That assumes a mixture of feedstocks consisting of grass and wheat straw, corncob or stover, manure, waste grease and glycerine. Numerous studies conducted by U.S. Department of Agriculture, Oregon State University, other universities and bioenergy developers are cited as source for this basis estimate.

Studies show an average of .3 cubic meters of methane (CH₄) per kilogram of biomass, or 4.8 cubic feet of methane gas per pound of feedstock. Methane at concentrations of 80% has some 1,000 British Thermal units of energy per cubic foot. For the purpose of this estimate a conservative value of 2 million British Thermal Units of energy per ton is assumed. That value was determined by laboratory biogas trials to determine biogas and methane yields from various Willamette Valley feedstocks. Two million Btu's per ton assumes an approximate blend of 63% ryegrass straw, 32% manure and 5% glycerine.

Therefore an AD system requires some 10.4 tons of feedstock per hour to produce the 20,700 standard cubic feet per hour of methane or 20.7 million Btu/hr to operate the 2 MW gas engine generator. Annual feedstock and AD through-put would require some 87,400 tons of mixed feedstocks per year. The analysis assumes that 50,000 tons are annual rye grass straw and the remaining 33,400 tons is a mix of food processing greens, and some 4,000 tons of glycerine.

Biogas produced in an anaerobic digester contains methane (60-70%), carbon dioxide (30-40%), water (1-2%), and trace levels of other gases such as hydrogen, carbon monoxide, nitrogen, oxygen, and hydrogen sulfide. The relative percentage of these gases in biogas depends on the feed material and management of the process. For ideal combustion in an engine generator this biogas needs to be upgraded. To upgrade biogas and remove toxic contaminants, a new family of polymeric or cellulose membranes with exceptionally high carbon dioxide and water permeance, and moderate carbon dioxide/ methane selectivity are being used. These membranes are optimized for better separation performance and reproducibility.

The following performance and controls characteristics provide the basis for analysis of the digester gas electrical and thermal energy generation of a 2 MW capacity system. In general systems should be compared based upon International Standards Organization (ISO) 3046/1 standard reference conditions and natural gas having a methane number of 70 or higher. Power output may require adjustment for values other than ISO3046/1 standard reference conditions. Manufacturers of commercially available systems meeting these general specifications include, but are not limited to, Caterpillar, Cummins, GE Jenbacher, and Wartsilla. Depending on the manufacturer, one or two engine/generators would be required to produce 2 MW of capacity.

Cost and performance estimates in this plan assume one machine. Fuel consumption and energy generation assumes 100% load factor at 80% power factor (pf) for 8,400 hours per year (15 days shutdown averaged over all months). Analysis of performance assumes an overall electrical production efficiency of 35% that is easily achieved by equipment in various steady state operations. Heat recovery estimates assume that thermal loads on-site are not always coincident nor at assured volumes or rates that allow for maximum heat exchanger efficiencies to be achieved. The heat rejection to atmosphere from the engine and generator are not recoverable. The heat recovered is assumed to be from the engine water jacket Stage 1 and exhaust at the lower heating value of 350 degrees Fahrenheit. That results in some 8.3 million Btu/hr of waste heat available for recovery or 40% of the 20.7 million Btu per hour of fuel consumption at full load. Average annual heat exchange efficiency and recovery to loads is estimated at 25% or 2 million Btu's per hour.

Two types of generators are used on farms: induction generators and synchronous generators. Induction generators operate in parallel with the utility and cannot operate as a stand-alone power source. Induction generators derive their phase, frequency and voltage from the utility. Synchronous generators operate as an isolated system or in parallel to the utility, and require more sophisticated intertie systems to match output to utility phase, frequency and voltage.

Control systems are required to protect the engine and the utility. Control packages are available that can shut the engine off due to mechanical problems, utility power outage or utility voltage and frequency fluctuations, or in the event that excess power is generated that the utility will not accept. Generators that operate in parallel with the utility system, such as induction generators, require an intertie system with safety relays to shut off the engine and disconnect from the utility in the event of a problem. Intertie negotiations with a utility for induction generators are typically much easier than for a synchronous generator, due to the level of control the utility has over the characteristics of power entering the grid from an induction generator. The primary advantage of a synchronous generator is its ability to act as a stand-alone power source. However, if operated as an isolated system, a synchronous generator must be oversized to meet the highest electrical demand, while operating less efficiently at average or partial loads. Due to the system size and more complicated control requirements, a synchronous generator operating as an isolated system is typically more expensive than an induction generator.

Biogas engines reject approximately 75 to 82 percent of the energy input as waste heat. This waste heat can be used to heat the digester and/or provide water or space heat to the facility. Commercial heat exchangers can recover waste heat from the engine water cooling system and the engine exhaust, recovering up to 7,000 Btu/hour for each kW of generator load. Waste heat recovery increases the energy efficiency of the system to 40 to 50 percent.

Generator Set — 1800 rpm/60 Hz/480 Volts

Excitation - Permanent magnet

Pitch - 0.6667

Number of poles - 4

Number of bearings 2

Number of leads - 6

Insulation - UL 1446 Recognized Class H Insulation

IP rating - Drip proof IP22 Alignment. - Pilot shaft

Overspeed capability - 125%

Wave form - Less than 5% deviation

Paralleling kit droop transformer - Standard

Voltage regulator - 3-phase sensing with adjustable 1:1 or 2:1 Volts/Hz, UL 508A

Listed TIF - Less than 50

Total Harmonic Distortion (THD)- Less than 3%

Generator efficiency - 96.7% based on 0.8 power factor (pf) with medium voltage class generator; actual efficiency will depend on generator selection.

Engine

Compression ratio - 11.1:1 or 11.3:1

Aspiration - Turbocharged, Separate Circuit Aftercooled

Fuel system - Electronic Ignition System

Governor type - Electronic Engine Control Module

Duty Rating – Continuous

Cool Heater - 208 to 480 V, Sub 40 F

Engine Air Cleaner – Dual Element, Single Pass Fabric Filters, Normal Duty

Gas Engine/Generator Controls

Fuel/air ratio control;

Start/stop logic: gas purge cycle, staged shutdown;

Engine Protection - detonation sensitive timing, high exhaust temp. shutdown;

Governor: Transient richening and turbo bypass control;

24 Volt DC Control

NEMA 1, IP22 enclosure

Electrically dead front

Lockable hinged door

Generator instruments meet ANSI C-39-1

Terminal box mounted

Single location customer connector point

EC compliant - segregated AC/DC connections and wiring

Voltage adjustment potentiometer

True RMS AC metering, 3 phase

Purge cycle and staged shutdown logic

Digital indication for: RPM Operating hours

Oil pressure

Coolant temperature DC voltage L-L volts, L-N volts, phase amps, Hz, ekW, kVA, kVAR, kWhr, %kW, pf

System diagnostic codes

Shutdown with indicating lights; Low oil pressure

High coolant temperature High oil temperature

Overspeed Overcrank

Emergency stop

High inlet air temperature (for TA engine only)

Detonation sensitive timing (for LE engine only)

Programmable protective relaying functions:

Under / Over voltage

Under / Over frequency

Overcurrent

Reverse power

Spare indicator LEDs

Spare alarm/shutdown inputs

Display - Control Graphical

Meters - AC output, analog or preferably digital Omni B Class meters with multiple open registers

Paralleling switchgear

Rated at 12,470 V. T.

The power is then increased to 69,000 V by an outdoor transformer before connecting to the distribution lines.

Energy Performance

Fuel Consumption		<u>scf/hr</u>
100% load w/o fan	20,800	
75% load w/o fan		16,000
50% load w/o fan	11,400	

Heat Rejection		<u>Btu/hr</u>
Jacket water and oil cooler and AC – Stage 1 4.1 million		
AC - Stage 2	492,000	
Exhaust (LHV to 350 Deg F)		4.2 Million
Atmosphere from engine		529,000
Atmosphere from generator	236,000	

Power Rating

0.8 pf (2 water pumps, no fan)	2,060 kW Continuous
0.8 pf (water pumps , no fan) 2,480	kVa Continuous
1.0 pf (2 water pumps, no fan)	2,110 kW
Electric Efficiency @ 1.0 pf (ISO 3046/1)	37 %
Mechanical Loads (2 water pumps, no fan)	2,800 bhp

Emissions

Certified, EPA, Tier 2, NR, CI

	grams/brake	horsepower/hour
NOx @ 5% O2 (dry)	1	
CO @ 5% O2 (dry)	2.36	
THC @ 5% O2 (dry)	4.01	
NMHC @ 5% O2 (dry)	.61	
Exhaust O2 (dry)	1.77%	

Overview of Digestate to Compost Technology

Digestate Characteristics

There are three types of digestate products: Whole digestate, separated liquor and separated fiber.

Whole digestate: the processed material as it is unloaded from the digester. Whole digestate generally contains coarse fibers, and liquids

Separated liquor: the liquid resulting from passing whole digestate through a separator or centrifuge to remove the coarse fibers. The liquor is highly suitable for growing crop application. It is an ideal fertilizer for grassland or for foliar application as there is negligible surface residue after spreading; it can also be used for hydroponic feeding as most of the nitrogen content is in forms of ammonium. This is the form of Nitrogen plants can use directly, however it also means the Nitrogen can be easily lost through volatilization. It is advised that Liquor is applied directly on the ground surface or by shallow injection. To get the best effect it is advised not to spread in strong sunlight or with drying wind.

A large number of different types of separator are utilized for digestate separation, and each of these are capable of producing separated liquor products with different qualities.

Nitrogen compounds are concentrated in AD effluents and require special attention. Reactive nitrogen compounds are accumulating on earth causing eutrophication in receiving waters and deterioration of ground water quality. Costs are associated with extra treatment required to reduce discharge concentrations. There are number of physicochemical and biological techniques available for the treatment of nitrogen containing waste streams.

Liquid digester effluent treatment systems can include equipment to produce pelleted fertilizer and irrigation water or concentrated effluent as liquid fertilizer and irrigation water. The proposed system will concentrate the liquid portion into fertilizer and route nutrient rich solids to compost.

Pelleted The process to pelletize the solids and chemical properties of liquid effluents at least includes nitrification. The first biological conversion stage is where ammonium is converted to nitrite using nitrifying bacteria in an aerated reactor. Then a subsequent chemical oxidation stage converts nitrite to nitrate by heating the liquid waste biomass in an aerated reactor under acidic conditions. The process is particularly suitable for treating liquid manure, because of the high ammonium nitrogen content, but it works on mixed organic waste digester effluent as well. This post treatment process can transfer more than 90 percent of the nutrients from the liquid effluent. The resulting liquid contains very low levels of nitrogen and phosphorous which fall within the nutrient management restriction, permitting the water to be used for direct irrigation or reintroduction to the digester.

To pelletize the nutrients, the liquid portion of the effluent is run through a dissolved air flotation (DAF) process to further separate out the bulk of the suspended solids in the liquid. The solids are where the majority of the phosphorous is located. The DAF tank, which operates under anaerobic conditions, is designed to spin on its horizontal axis.

Liquid effluent is introduced into the DAF where it is mixed with a polymer that causes the solids to clump. Biogas injected into the bottom of the tank lofts the suspended solids in the effluent to the top of the tank, where they are removed and either pumped back into the digester to create more biogas or added to the biofibers for pelletization. Up to 70 percent of the nitrogen in the waste is converted to ammonia.

Ammonia is the primary nitrogen constituent in pellet or liquid fertilizer produced from effluent. As much as 50% of that is subject to aromatic release to the atmosphere in land application.

Densification of the biofibers into pellets allows for the efficient storage and transport of the nutrients. Pellets created by the process can be either spread on fields in a single-pass operation or sold as fertilizer. Since pellets are only applied once a year, compared to four times a year for manure, they also reduce soil compaction and vehicle emissions. Investigations are also underway to determine how the commercial value of the pellets can be enhanced. One option is to add composted poultry manure, which is high in nitrogen that can supplement the lower nitrogen effluent from non-manure, organic mixed waste digesters.

In other applications a fertilizer production plant receives cake (25% solids) from a digester solids centrifuge and concentrated liquid fertilizer from a freeze-thaw system that separates water and soluble salts because of the differing freezing points. These feedstocks (cake and concentrated nutrient liquid) are mixed prior to granulation and drying. A rotary drum dryer with a 2.1-m (7-ft) inside diameter and is 12.8 m (42 ft) long is used to both granulate and dry the fertilizer. The dryer drum incorporates a specially designed granulation section at the head of the dryer to complete the granulation of the materials prior to drying. This system requires refrigeration energy use in climates where seasonal atmospheric freezing is unavailable.

A burner, using biogas from the digesters, is designed to dry the fertilizer in the rotary drum and provide for the introduction of recycled process gases prior to a slip-stream being vented to the stack, via an air pollution control system. The combustion chamber is designed to thermally oxidize volatile organic compounds (VOCs) in the exhaust gases for odor control. A significant amount of ammonia can be lost in this type system. A heat exchanger is used for the recovery of energy from the combustion/thermal oxidizer chamber to maintain the digesters at design temperature.

Another process recovers ammonia as struvite or magnesium ammonium phosphate (MAP). The techniques such as biological nitrification/denitrification and breakpoint chlorination reduce nitrogen compounds to dinitrogen gas. However, alternative technologies exist to convert ammonia into reusable and saleable useful product thus contributing overall nitrogen cycle. One such technology is the recovery of ammonia as struvite which has a potential as fertilizer.

Liquid Fertilizer Concentrate

Liquid digester effluent nutrients can be concentrated into a solution and the water separated. The water meets standards that allow its use back in the digester, in adjacent industrial applications or for irrigation. The digestate or effluent is sent through a screw press to reduce water content. Then it goes through flocculation and a decanter to further remove solids. Ultrafiltration is done to remove smaller solids under 100,000

microns and then the liquids are put through reverse osmosis filtration and separated into a clean water and centrate that is nutrient rich. The following diagram shows digester solids separation and liquids separation and concentration processes.

Many manure digesters take un-concentrated effluent and return it to direct grazing land application. That is often limited by the nature of the soil or the runoff from the site. In some watersheds liquid effluent storage is required because land application, on highly saturated soils, is allowed only during the growing season to prevent nutrient runoff.

The fertilizer value of liquid concentrates is illustrated in the following table. The solids fraction are nutrient rich as well and provide good feedstock for compost. Those can be pelletized and land applied or sold as bulk fertilizer. The liquid concentrate can be sold as organic fertilizer and pricing of \$0.20 per gallon makes it cost competitive with inorganic fertilizers at up to 100 miles hauling distance from the digester site. .

Separated fiber: the coarse fiber separated out of the whole digestate when producing Liquor. The fiber contains significant quantities of nutrients and has excellent water retention properties, making it an excellent soil conditioner. It can be directly applied to land or turned into composted before application.

Separated fiber can be spread directly on agricultural land by standard design solid manure spreaders. Most practices incorporate the fiber application onto ploughed land or on grassland in Autumn or early spring to get the best effect.

The fiber after aerobic composting to stabilize it, can be turned into a compost product, soil conditioner or mulch, featuring slow release nutrients for plants.

Overview of Cellulosic Ethanol Technology

Ethanol has developed as the primary liquid biofuel of choice for spark ignition engines. Methanol and synthetic gasoline have potential but remain secondary alternatives at this point in time. Over the past several years a host of routes to ethanol have been developed. The principal route has been by fermentation of sugar and this is likely to continue but the source of sugar will probably change dramatically and thermochemical routes are expected to begin to play a significant role as well.

The composition of a number of representative biomass feedstocks is provided in the following table:

Table 2 Composition of Selected Biomass Species

Species	Cellulose (%)	Hemicellulose (%)	Lignin (%)	Extractives (%)	Ash (%)
Hybrid Poplar	39.23	16.66	25.18	6.89	2.03
Monterey Pine 41.7		20.5	25.9	2.7	0.3
Corn Stover	36.51	22.82	19.25	7.74	11.04
Wheat Straw	32.64	22.63	16.85	12.95	10.22
Switchgrass 30.97		24.39	17.56	12.97	6.22
Tall Fescue	24.46	19.45	14.72	19.83	14.3
Ryegrass					
Straw	30-34	23-27	9-13.	9-20.	6-8.

Source: USDA

Biomass consists of the three principal components; cellulose, hemicellulose and lignin. Cellulose is a highly crystalline polymer of the sugar, glucose, shown in the following figure.

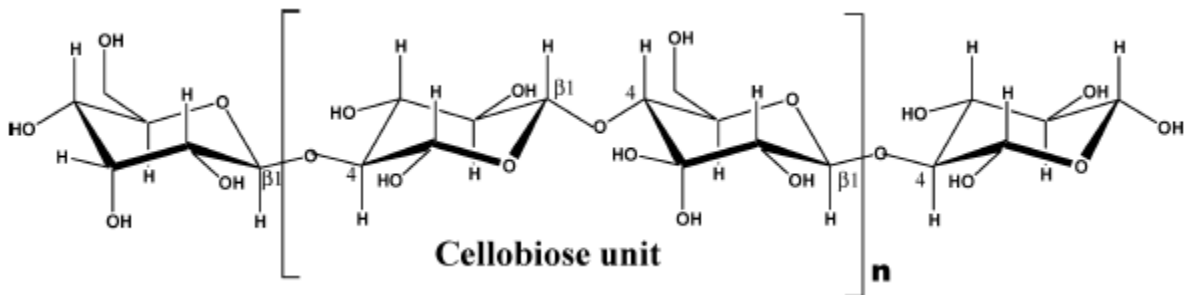


Figure 5 Chemical Structure of Cellulose

Hemicellulose is also a polymer of glucose but contains other five and six carbon sugars as well and is not crystalline like cellulose. Together these make up 55-65% of the total biomass. A third biopolymer, lignin, is shown in the following figure:

Lignin is made of aromatic subunits and serves as a sort of “glue” binding the crystalline fibers of cellulose together. Because of the predominance of these components, biomass is often referred to as “lignocellulose”. In addition to these large biopolymers, there are extractives which are small water-soluble compounds such as sugar and acetic acid. There is also ash which contains minerals such as sodium and potassium salts. Woods are highest in lignin and cellulose, crop residues are intermediate and grasses contain the least amount of lignin and cellulose.

Most biomass sources contain insignificant amounts of fermentable sugar, which would show up in the extractives, but are rich in cellulose and hemicellulose which can be hydrolyzed (broken down) to fermentable sugar. Biomass can also be gasified by rapid heating in the presence of oxygen and/or steam and purified to synthesis gas, a mixture of carbon monoxide (CO) and hydrogen (H₂) which can, in turn, be catalytically converted to ethanol. It is actually simpler to convert synthesis gas to methanol or synthetic gasoline or diesel but conversion to ethanol takes advantage of the extensive infrastructure already in place for distributing and marketing ethanol.

The area that has received the greatest attention historically has been the biochemical conversion route. The cellulose is a highly crystalline biopolymer that is bound together in tight fibers, interspersed with hemicellulose polymers and “glued” together with lignin. The challenge has been to remove or disrupt the lignin enough to make the cellulose and hemicellulose polymers accessible so that enzymes or chemicals can hydrolyze these polymers into fermentable sugars. Lignin has proven very resistant to attack as the review of pretreatment research will demonstrate. The pretreatment steps required to make cellulose available to hydrolysis has made such processes costly and has slowed down commercialization and stimulated the search for alternative pathways.

The biochemical conversion route for grasses is somewhat more attractive than for biomass in general. Grasses contain considerably less lignin and are generally richer in extractives. Some of these extractives are fermentable sugar. A solution of extractives could be fermented to ethanol although the ethanol concentration would be too low to be commercially feasible to be done alone. The low lignin content means that only a mild pretreatment would be needed to remove and/or disrupt the lignin enough to make the cellulose and hemicellulose available for hydrolysis. This should greatly reduce the complexity and cost of this step. These factors make ethanol production from grasses quite different from most other lignocellulosic materials.

Three principal technology types exist:

The first type is thermochemical conversion. This technology takes the feedstock and breaks it down into gases by gasification. The gases are then recombined using catalysts to give ethanol mixed with some methanol and other alcohols. This approach has the advantage of accepting a wide range of feedstock types but there is little experience with fully integrated systems producing mixed alcohols.

The second technology type uses acids to break down the cellulose to sugar which is then fermented to ethanol. This technology has long been proven but must be carefully controlled to avoid sugar decomposition and requires stainless steel reactors.

The third technology uses enzymes to break down the cellulose which is highly efficient but feedstocks require effective pretreatments for the enzymes to work and processes are very feedstock sensitive.

Pretreatment

It is generally necessary to pretreat the biomass to make the cellulose accessible to hydrolysis. Steam explosion has proven an effective pretreatment for a wide variety of crop residues. Where the lignocellulose proves more resistant to steam explosion alone, the lignin can be extracted with alkali and/or reacted with oxidants. Post treatment with H₂O₂ after steam explosion is somewhat effective but too costly for commercial application.

Another wholly different approach is to use organic solvents to dissolve the lignin away from the cellulose. Processes have been developed employing acetone, acetic acid and ethanol for this purpose. The best known process, the Lignol process, employs aqueous ethanol.

In the case of ryegrass straw, one should probably be able to use the mildest pretreatment available, some form of steam treatment, to get sufficient disruption of the lignin to enable cellulose hydrolysis. One would probably want to first remove the extractives since this is such a large component in such leafy feedstocks.

Enzymes

Enzymes were subsequently discovered that were capable of efficiently hydrolyzing cellulose to glucose selectively and at room temperature

One reason cellulose production technology development has proven so difficult is that the term “cellulase” is actually describing a group of five enzymes; endo-cellulase, exo-cellulase, cellobiase, oxidative cellulases and cellulose phosphorylases. All five enzymes are needed for the transformation ascribed to “cellulase” to work. The same applies to “hemicellulase”. It is assumed that “cellulase” is also able to hydrolyze hemicelluloses as well, that is, to contain “hemicellulase” as well.

Fermentation

The historical ethanol fermentation has been the conversion of single sugars like glucose to ethanol using the yeast, *Saccharomyces cerevisiae*. The bacterial fermentation of agave to produce tequila is the only exception. The yeast fermentation is still the most common ethanol fermentation in use today.

To effectively utilize all the sugars in lignocellulosic feedstocks, one needs to find a means of fermenting the five carbon sugars that are also present in such raw materials.

Incentives, Renewable Energy Credits, tradable certificates

There are a variety of government loan and grant programs that the private sector can use for this project:

- Oregon Business Energy Tax Credit (BETC)
- State Energy Loan Program (SELP)
- State Energy Program (SEP)
- US DOE Loan Program
- USDA RD Loan Program
- Federal Production Tax Credit
- American Recovery and Reinvestment Act Bonds
- Federal Appropriations

Oregon Business Energy Tax Credits

The Oregon Business Energy Tax Credit can be applied to 50 per cent of the eligible project costs up to a maximum of \$20 million in eligible costs for Renewable Energy Resource Generation projects.

A project owner also can be an Oregon non-profit organization, tribe or public entity that partners with an Oregon business or resident who has an Oregon tax liability. This can be done using the Pass-through Option.

The Pass-through Option allows a project owner to transfer their Business Energy Tax Credit project eligibility to a pass-through partner for a lump-sum cash payment. A project owner may be a public entity or non-profit organization with no tax liability or a business with tax liability that chooses to use the Pass-through Option.

The tax credit can cover all costs directly related to the project, including equipment cost, engineering and design fees, materials, supplies and installation costs. Loan fees and permit costs also may be claimed.

BETC Administrative Rule Update Notice, Dated May 25, 2010

Oregon Department of Energy filed new temporary administrative rules for portions of the Business Energy Tax Credit (BETC) program on Friday, May 21. The new rules took effect May 27, 2007

This is the second phase of BETC rulemaking. The first phase of rule changes filed in November 2009 slowed the growth of the BETC program and created sideboards to provide more predictability, timeliness and consistency to reduce the impact on the state's general fund. They also eliminated the practice of multiple applications for the same or similar projects and established new criteria for project eligibility and performance standards. Following public input, permanent rules to replace the November temporary rules were filed on April 30, 2010

In this second phase, new rules implement program caps, tiers and project criteria that reflect changes requested by the Legislature in House Bill 3680 passed by the 2010

Legislature. They also include rules to simplify the BETC pass-through option's rate formula and provide a uniform rate structure for the program as a result of House Bill 2068 passed in 2009.

Under HB 3680 renewable energy tax credits are capped at \$300 million for the current biennium (July 1, 2009 to June 30, 2011). The Department has issued \$218 million as of May 10, with the remainder to be distributed through the end of the biennium. A new tiered system has established funding cycles that are unique to each tier.

Tier One is for small projects with under \$500,000 in eligible project costs (maximum tax credit of \$250,000). \$10 million is available in the current funding cycle (June 1, 2010 through December 31, 2010). Application requirements have few changes and are processed on a first-come basis over the ongoing funding period.

Tier Two includes projects with eligible projects costs ranging from \$500,000 to under \$6 million (maximum tax credit of \$3 million). For the June 1 to August 31, 2010 funding period, \$10 million is available and another \$10 million covers the October 1 to December 31 funding period. Tier Three eligible project costs are \$6 million and above (maximum tax credit of \$10 million). \$30 million is available. Both Tier Two and Three require a competitive review and award process.

The temporary rules are effective for 180 days ending Nov. 2, 2010. Rules are posted on the Department's Web site at

<http://www.oregon.gov/ENERGY/CONS/Rulemaking2009-BETC.shtml>

State Energy Loan Program

The purpose of the Oregon Energy Loan Program is to promote energy conservation and renewable energy resource development. The program offers low-interest loans for projects that:

- Save energy
- Produce energy from renewable resources such as water, wind, geothermal, solar, biomass, waste materials or waste heat
- Use recycled materials to create products
- Use alternative fuels

The Energy Loan Program can loan to individuals, businesses, schools, cities, counties, special districts, state and federal agencies, public corporations, cooperatives, tribes, and non-profits. Projects must be primarily in Oregon.

Oregon State Energy Program (SEP)

Oregon plans to use funding from the American Recovery and Reinvestment Act to fund energy efficiency improvements, develop renewable energy resources, and ensure environmental protections through the established State Energy Program.

The Oregon Department of Energy is allocating \$3,000,000 to Biomass projects. Under the rules, projects can start as early as June 2010 and be completed on or before February 12, 2012. The funding will be in the form of a State Energy Program (SEP) grant under ARRA. This new opportunity will allow the department to extend ARRA opportunities beyond the typical public building projects to projects targeted at the private sector.

The projects will be evaluated on a variety of metrics, including:

- Energy Produced;
- Jobs created/retained;
- Benefits to local community;
- Biomass Resource Availability;
- Opportunity for long-term energy production;
- Project team's capacity to deploy the project and meet all grant compliance and reporting requirements; and
- Overall ARRA requirement to ensure the state realizes 10 MMBtu energy produced per \$1,000 spent statewide.

US DOE Energy Loan Program

The U.S. Department of Energy will provide up to \$60 billion in loan guarantees for renewable energy projects.

Title XVII of the Energy Policy Act of 2005 established DOE's innovative technologies loan guarantee program (the Section 1703 Program), which was designed to support projects that are unable to obtain conventional private sector financing due to technology risks. Only projects in the U.S. that reduce greenhouse gases and employ **new or significantly improved technology** are eligible for the Section 1703 Program.

The Recovery Act broadened the section 1703 program by adding Section 1705 (the Section 1705 Program) to the Energy Policy Act, creating a temporary loan guarantee program for renewable energy, transmission and advanced biofuels projects in the U.S. that commence construction by September 30, 2011. The Section 1705 Program is intended to support projects that are unable to obtain private loans due to the credit crisis, including projects that **do not employ innovative technology**.

One of the most significant features of the Section 1705 Program is that the so-called "Credit Subsidy Cost" is funded by the government. The Credit Subsidy Cost is the amount that DOE is required to hold on reserve to cover estimated potential losses in accordance with the Federal Credit Reform Act of 1990, which is a percentage of the guarantee that is calculated by DOE on a project-by-project basis. In the case of loan guarantees for projects that can qualify only under the old Section 1703 Program (for example, because they will not commence construction by September 30, 2011), borrowers must pay the entire Credit Subsidy Cost prior to closing.

For renewable energy projects that use technologies that are already in general use in the marketplace, DOE's FIPP solicitation requires borrowers to first contact a financial institution (a Lender-Applicant) regarding its loan. Upon reaching agreement with a borrower on terms for the project loan, the Lender-Applicant will apply to DOE for a guarantee of up to 80 percent of that loan.

FIPP is designed for simple finance structures without complex tax equity arrangements. DOE delegates the due diligence, loan structuring and documentation work to private sector lenders to accelerate the process for providing financing for shovel-ready renewable energy projects that will create jobs in the U.S.

A change in the program made in early 2010 allows state lending programs, like Oregon SELP to act as the lender, so that a private sector lender is not needed in the project.

Eligibility Requirements

In addition to the "Commercial Technology" requirement described above, projects must satisfy the following key eligibility requirements in order to qualify for FIPP:

- Projects must achieve a credit rating equivalent to BB from S&P or Fitch or Ba2 from Moody's, as evaluated without the benefit of the guarantee;
- Projects must commence construction on or before September 30, 2011;
- Projects must be located in, and create or retain jobs in, the U.S. or its territories or possessions;
- Borrowers must pay all laborers and mechanics employed for the project prevailing wages, as determined under the Davis-Bacon Act; and
- The borrower or other principals must make a "significant" equity investment in the project.

Loan and Loan Guarantee Terms

The Loan Agreement and the Guarantee Agreement will be subject to the following key terms and conditions:

- The face value of the loan guaranteed by DOE may be for no more than 80 percent of eligible project costs;
- DOE may guarantee up to 80 percent of the loan (the remaining 20 percent of the loan will be on an uncovered basis);
- The term of the loan may be up to the lesser of 30 years or 90 percent of the projected useful life of project assets;
- DOE will permit lenders to freely transfer economic or beneficial interests (but not legal rights) through loan participations, but any actual transfer or syndication will require DOE approval; and
- DOE will be a party to the Loan Agreement and will reserve the right to exercise all voting and control rights customarily provided to majority lenders.

Application and Review Process

DOE's application and review process consists of three general phases: (1) submission of the Part I Application, (2) submission of a Part II application and (3) loan guarantee documentation.

Lender-Applicants may submit Part I Applications at any time and DOE will conduct rolling reviews. Part I Applications must include summary-level information about the project, project sponsor and lenders. DOE will advise the Lender-Applicant whether the project appears to qualify for the Section 1705 program to help the Lender-Applicant decide whether to proceed to Part II.

If its Part I Application is approved, the Lender-Applicant may submit its Part II Application during any one of ten scheduled rounds of review. Part II Applications must include lender certifications and detailed project information, including an Information Memorandum, an independent engineering report, a credit rating and copies of all financing and project agreements.

DOE will competitively evaluate all Part II Applications received in a given round. DOE's review will be based on, among other things, the readiness of the project for financing,

financial strength of the project and the extent to which lenders intend to hold their investments.

DOE intends to inform the Lender-Applicant of its decision regarding the application within two months of the Part II submission. If DOE approves the project, DOE, the Lender-Applicant and the borrower will negotiate a Term Sheet and execute a Conditional Commitment. Upon satisfaction of the terms in the Conditional Commitment, DOE and the Lender-Applicant may execute a Guarantee Agreement and proceed with financial closing.

Federal USDA RD Loan Program

The Rural Energy for America Program, formerly section 9006 under the 2002 Farm Bill, is composed of several types of grants and guaranteed loan programs. These are: Guaranteed loans and grants for the development/ construction of renewable energy systems and for energy efficiency improvement projects; grants for conducting energy audits; grants for conducting renewable energy development assistance; and grants for conducting renewable energy feasibility studies.

Borrowers must be an agricultural producer or rural small business. Agricultural producers must gain 50% or more of their gross income from their agricultural operations.

Eligible project costs include:

- 1) Post-application purchase and installation of equipment,
- 2) Post-application construction or improvements,
- 3) Energy audits or assessments,
- 4) Permit or license fees,
- 5) Professional service fees,
- 6) Feasibility studies and technical reports,
- 7) Business plans,
- 8) Retrofitting,
- 9) Construction of a new energy efficient facility only when the facility is used for the same purpose, is approximately the same size, and based on the energy audit will provide more energy savings than improving an existing facility,
- 10) Working capital,
- 11) Land acquisition.

Federal Tax Credits

American Recovery and Reinvestment Act Digester Incentives

Section 1142 of the American Recovery and Reinvestment Act of 2009 (ARRA) provides renewable energy incentives for open and closed loop biomass facilities such as woody biomass to energy or digesters that generate electricity.

New Clean Renewable Energy Bonds

Section 1111 of the ARRA increases the amount of funds available to issue new clean renewable energy bonds from the one-time national limit of \$800 million to \$2.4 billion. These qualified tax credit bonds can be issued to finance certain types of facilities that generate electricity from renewable sources (for example, wind and solar).

Extension of Renewable Energy Production Tax Credit

(Section 1101): The new law generally extends the "eligibility dates" of a tax credit for facilities producing electricity from wind, closed-loop biomass, open-loop biomass, geothermal energy, municipal solid waste, qualified hydropower and marine and hydrokinetic renewable energy. The new law extends the "placed in service date" for wind facilities to Dec. 31, 2012. For the other facilities, the placed-in-service date was extended from December 31, 2010 (December 31, 2011 in the case of marine and hydrokinetic renewable energy facilities) to Dec. 31, 2013.

Section 45 of the Internal Revenue Code provides a tax credit of up to ~2¢ per kWh for electricity generation from biomass feedstock.

A biomass project's tax owner can either elect to take (1) the PTC on a yearly basis for 10 years; or (2) as a one-time lump sum cash payment in the first tax year after commercial in-service.

Election of Investment Credit in Lieu of Production Credit

(Section 1102): Businesses who place in service facilities that produce electricity from wind and some other renewable resources after Dec 31, 2008 can choose either the energy investment tax credit, which generally provides a 30 percent tax credit for investments in energy projects or the production tax credit, which can provide a credit of up to 2.1 cents per kilowatt-hour for electricity produced from renewable sources. A business may not claim both credits for the same facility.

Coordination with Renewable Energy Grants

(Section 1104): Business taxpayers also can apply for a grant instead of claiming either the energy investment tax credit or the renewable energy production tax credit for property placed in service in 2009 or 2010. In some cases, if construction begins in 2009 or 2010, the grant can be claimed for energy investment credit property placed in

service through 2016, and for qualified renewable energy facilities, the grant is 30 percent of the investment in the facility and the property must be placed in service before 2014 (2013 for wind facilities).

National Cellulosic Ethanol Incentives - Energy Policy Act 2005

The cellulosic ethanol facility in this plan will produce up to 200,000 gallons of advanced biofuels per year. It will be eligible for blending tax credits, the small ethanol producer tax credit, and secondary market sales of Renewable Identification Numbers. In addition, the capital investment is eligible for both loan guarantees and matching grants under the Biomass Research and Development (Section 941) funds.

RFS: cellulosic ethanol: under the RFS, one gallon of cellulosic or waste-derived ethanol counts as 2.5 gallons through 2012. After that, the ratio no longer applies and cellulosic biomass ethanol must be included in the nation's annual fuel mix.

Small ethanol producer (Section 1345-1347): expands the definition of a small ethanol producer to include plants of up to 60 million gallons per year capacity; and creates a production incentive of 10 cents per gallon on the first 15 million gallons of ethanol produced each year.

Biomass research and development (Section 941): expands the Biomass Research and Development Act of 2000 in conjunction with DOE, USDA and EPA; increases authorization from \$54 million to \$200 million per year from 2006-2015; and includes grants to state research agencies. Includes cellulosic biomass research.

Production incentives for cellulosic biofuels (Section 942): authorizes incentives to ensure that annual production of one billion gallons of cellulosic biofuels is achieved by 2015. Authorizes \$250 million for 10 years.

Loan guarantees and grants (Section 1512): authorizes loan guarantees and grants for construction of facilities to process and convert municipal solid waste and cellulosic biomass into ethanol and other products.

Advanced biofuels technologies (Section 1514): creates an Advanced Biofuels Technologies Program of \$550 million.

Volumetric Ethanol Excise Tax Credit (VEETC) - \$0.51 Per Gallon

The American Jobs Creation Act of 2004 (H.R. 4520) includes the provisions of the Volumetric Ethanol Excise Tax Credit (or the Blender's Credit) and extends to 2010 its effective date. The VEETC is a credit of \$.51 for every gallon of pure ethanol blended into gasoline. It is an incentive not to ethanol producers, but to the petroleum industry to blend ethanol into its gasoline. Any blend of ethanol with gasoline is eligible for the credit, including E85.

An E10 blend has a credit available of \$.051/gallon, and E85 has a credit available of \$.4335/gallon. The Blender's Credit benefits taxpayers because the tax credit is

generally passed on to the consumers at the gas pump. Consumers also benefit in that these blends offer a higher-quality, higher-octane fuel. This credit is refundable quarterly, and paid out of the General Fund of the federal budget.

Renewable Identification Numbers

Under the national Renewable Fuels Standard (RFS) 2 enacted by the Energy Independence and Security Act of 2007, the process of transferring renewable fuel requires the use of a complex identification process for each gallon of fuel produced or imported into the United States. Starting in September 2009, the process is centered on a 38-digit code, termed the Renewable Identification Number (RIN). As ethanol is produced or imported, the producer or importer has the responsibility to assign this series of numbers to their product. Assignment is made according to guidelines established by EPA and found within the RFS regulations. Note that EPA does not assign the actual RIN number, nor does it maintain a registry for these numbers.

Once the RIN number is assigned to the fuel, it essentially becomes the renewable fuel credit. As product is then sold to the customer, it is now accompanied by the RIN. This transfer of physical fuel and the paper RIN credit requires proper transfer documentation be generated and transmitted as title is transferred to the product. Subsequently, each future transfer of renewable fuel accompanied by the RIN requires that each party in the chain generate the appropriate product transfer documents (PTDs). The PTDs serve as the basis for the recordkeeping and reporting requirements under the regulations.

RIN prices are affected by:

- 1) the gap between the price that fuel blenders pay to buy biofuels and the prices of biofuels implicit in blended fuels,
- 2) the transaction costs of trading RINs, and 3) speculation about whether or not the mandates will be binding in the near future, as well as whether or not there will be a waiver.

To qualify as a cellulosic ethanol or cellulosic biodiesel fuel for the purposes of Advanced Biofuel RINS a fuel must meet one of the following definitions: Cellulosic biofuel means renewable fuel derived from any cellulose, hemi-cellulose, or lignin that has lifecycle greenhouse gas emissions that are at least 60 percent less than the baseline lifecycle greenhouse gas emissions, or

Cellulosic diesel is any renewable fuel which meets both the definitions of cellulosic biofuel and biomass-based diesel, as defined in this section 80.1401. Cellulosic diesel includes heating oil and jet fuel made from cellulosic feedstocks.

Secondary Market for RIN Sales

The Farm Agriculture Policy Research Institute of the University of Missouri in FAPRI-MU Report #07 -09 published September 2009, identified the following forecast market price for RINS for Advanced Biofuel cellulosic ethanol, and the quantity required for the new cellulosic ethanol component of the RFS, in respective crop years.

Crop	RIN	Million
<u>Year</u>	<u>Value</u>	<u>Gallons</u>
10/11	\$1.03	24
11/12	\$0.92	64
12/13	\$0.84	137
13/14	\$0.79	245
14/15	\$0.75	391
15/16	\$0.70	576
16/17	\$0.66	804
17/18	\$0.62	1,079
18/19	\$0.58	1,404
19/20	\$0.53	1,779

Expansion of Allowance for Cellulosic Biofuels Property:

Under current law, taxpayers are allowed to immediately write off 50% of the cost of facilities that produce cellulosic ethanol if such facilities are placed in service before January 1, 2013. The bill makes the benefit available for the production of other cellulosic biofuels in addition to cellulosic ethanol.

Federal Appropriation

The Junction City project has been submitted by Lane County to the federal delegation as a United Front project.

- United Front is prioritization of most important local projects
- \$5 million funding request presented to Senator Ron Wyden, Senator Jeff Merkley and Representative Peter DeFazio.

The middle Willamette Valley project was submitted to Representative Schrader through regular federal appropriation process.

Biomass Crop Assistance Program (BCAP)

Biomass Crop Assistance Program (BCAP) provides financial assistance to producers or entities that deliver eligible biomass material to designated biomass conversion facilities for use as heat, power, biobased products or biofuels. Initial assistance will be for the Collection, Harvest, Storage and Transportation (CHST) costs associated with the delivery of eligible materials.

Eligible materials include:

- Pre- & Non-Commercially Valued Forest Materials (that WOULD NOT otherwise be used for higher-value products)
- Crop residues - For example: corn stover, corn cobs, rice hulls, wheat straw and bagasse are eligible after the commodity crop is harvested from the plant.

A biomass conversion facility, is a facility that converts or proposes to convert renewable biomass into heat, power, biobased products, advanced biodiesel, or advanced biofuels such as wood pellets, grass pellets, wood chips, or briquettes.

Renewable Energy Credits

Renewable Energy Certificates (RECs), also known as Green tags, Renewable Energy Credits, Renewable Electricity Certificates, or Tradable Renewable Certificates (TRCs), are tradable, non-tangible energy commodities in the United States that represent proof that 1 megawatt-hour (MWh) of electricity was generated from an eligible renewable energy resource.

These certificates can be sold and traded or bartered, and the owner of the REC can claim to have purchased renewable energy. While traditional carbon emissions trading programs promote low-carbon technologies by increasing the cost of emitting carbon, RECs can incentivize carbon-neutral renewable energy by providing a production subsidy to electricity generated from renewable sources. It is important to understand that the energy associated with a REC is sold separately and is used by another party. The consumer of a REC receives only a certificate.

In Oregon, a green energy provider (wind, biomass, solar, geothermal, biogas) is credited with one REC for every 1,000 kWh or 1 MWh of electricity it produces. A certifying agency gives each REC a unique identification number to make sure it doesn't get double-counted. The green energy is then fed into the electrical grid (by mandate), and the accompanying REC can then be sold on the open market.

Although Oregon recognizes only two types of REC's, either bundled (sold with the electricity) or unbundled (sold separate from the electricity), Oregon RECs are transacted in three ways. Those include purchases of REC's by the utility serving the renewable energy facilities, through a one-time above market cost reimbursement by the Energy Trust of Oregon, or through third party buyers of REC's such as Bonneville Environmental Foundation.

Energy Trust of Oregon - Above-Market Cost Program.

Above-Market Costs are the difference between what the power produced by a project is worth at standard rates and what it actually costs to produce the power from the project. Costs typically include capital costs, yearly expenses such as operations and maintenance, interest on debt, permitting, and other upfront and yearly expenses. Revenues typically include, but are not limited to revenue from power sales (or reduced power purchases), tax credits and benefits, sales of secondary products, and grants. The analysis is performed for multiple years, based on the typical operating life of the technology or application. Included in the analysis are the tax credits and benefits the project can utilize, which help offset the cost of producing the power. If the power from the project is cheaper than the price it can be sold at, then there are no Above-Market Costs.

There is no cap or fixed percentage of the amount of above-market costs Energy Trust will pay. When Energy Trust provides funding for a renewable energy project, it takes title to a share of the project's green tags proportional to its share of the above-market costs and in relation to the market value for those tags.

Bonneville Environmental Foundation

The Bonneville Environmental Foundation is a non-profit foundation focused on adding renewable power to the electricity grid. The Foundation invests in projects that reduce carbon emissions. The Foundation also partners with projects to sell the carbon offsets through the carbon markets.

Carbon Offset Credits

Purchase of carbon and other Green House Gas (GHG) offset credits in the United States is currently a voluntary market. There are various methods to certify a facility and register the credits for sale. There are Climate Reserve Tonnes (CRT's) from the Climate Action Reserve for carbon or methane in carbon equivalent credits. There are Certified Emission Reductions (CER's) through the Clean Development Mechanism (CDM), defined in Article 12 of the Kyoto Protocol.

At this time a digester using pre-consumer waste (rye straw, glycerine, food processor waste) or fats, oils and grease (FOG) as feedstock does not meet CRT standards and protocols adopted 7 October 2009. Mixed waste stream Organic Waste Digesters (OWD) must prove that the feedstock would have otherwise gone to a landfill or an anaerobic lagoon for disposal. Approval of a portion of the waste stream that is qualified like commercial food service waste can be accomplished by petition. No CRT value is estimated for this project.

Renewable Energy Credits

Renewable Energy Certificates (RECs), also known as Green tags, Renewable Energy Credits, Renewable Electricity Certificates, or Tradable Renewable Certificates (TRCs), are tradable, non-tangible energy commodities in the United States that represent proof that 1 megawatt-hour (MWh) of electricity was generated from an eligible renewable energy resource.

The 2 megawatt engine generator operating off the anaerobic digester gas will produce some 16,800 MWh of electricity annually. That electricity will be sold in a buy-all, sell-all contract with the local utility with an estimated annual 20 year lifetime average price of \$1.3 million. That is an average of \$79 dollars per MWh. The purpose of a buy-all, sell-all contract is that purchased electricity cost less than the avoided cost that the utility will pay for the produced electricity. Also, REC's are based on renewable energy to the grid. The renewable energy credits in today's market are worth about \$7.50 per MWh with a \$0.25 escalation per year or an average of \$9.88 per MWh over the 20 year life of the plant or an annual average of \$165,900 per year.

These certificates can be sold and traded or bartered, and the owner of the REC can claim to have purchased renewable energy. While traditional carbon emissions trading programs promote low-carbon technologies by increasing the cost of emitting carbon, RECs can incentivize carbon-neutral renewable energy by providing a production subsidy to electricity generated from renewable sources. It is important to understand that the energy associated with a REC is sold separately and is used by another party. The consumer of a REC receives only a certificate.

In Oregon, a green energy provider (wind, biomass, solar, geothermal, biogas) is credited with one REC for every 1,000 kWh or 1 MWh of electricity it produces. A certifying agency gives each REC a unique identification number to make sure it doesn't get double-counted. The green energy is then fed into the electrical grid (by mandate), and the accompanying REC can then be sold on the open market.

Western Renewable Energy Generation Information System (WREGIS), established in June 2007 and administered by the Western Electricity Coordinating Council (WECC), is an accounting system designed to issue, register and track RECs to verify compliance with regulatory requirements and participation in voluntary market programs throughout the western United States. WECC oversees electric reliability for more than 71 million people in 14 western states, two Canadian provinces, and the Northern portion of Baja, Mexico.

WREGIS issues one WREGIS Certificate for each MWh (1,000 kilowatt hours) of renewable energy generated by registered generation facilities. WREGIS users have private accounts, similar to bank accounts, where certificates are deposited upon creation. Once a certificate is created, it can be transferred, retired, or exported to a compatible tracking system according to the needs of the certificate owner.

The Center for Resource Solutions' Green-e® energy program is an independent, non-profit organization in San Francisco that certifies the authenticity of traded REC's. Retailers selling RECs with the Green-e logo are selling WRIGIS REC's or other GHG offset products verified by this organization.

Although Oregon recognizes only two types of REC's, either bundled (sold with the electricity) or unbundled (sold separate from the electricity), Oregon RECs are transacted in three ways. Those include purchases of REC's by the utility serving the renewable energy facilities, through a one-time above market cost reimbursement by the Energy Trust of Oregon, or through third party buyers of REC's such as Bonneville Environmental Foundation.

Bundled REC's Oregon utilities that serve more than 1.5% of the states electric load are required by statute to meet Renewable Portfolio Standards. Bundled REC's, where the REC is sold with the electricity, may be sold to utilities serving the 11 western United States comprising the Western Electricity Coordinating Council (WECC). Those utilities serving over 3% of Oregon's electric load must provide 5% renewable energy by 2011, 15% by 2015, 20% by 2020 and 25% by 2025. Utilities serving under 1.5% but less than 3% of the states electric loads must provide 10% renewable energy by 2025 with no interim requirements and that require them to provide To meet the RPS the utility must purchase and retire REC's from qualifying renewable energy facilities or directly own the qualifying renewable energy facility and retire the REC's from it. Portland General Electric, Pacific Power and Eugene Water and Electric Board fall into the category with interim targets. They are not currently purchasing REC's from renewable power producers, except in one case under a special contract (EWEB – Seneca). Idaho Power and most of Oregon's 36 consumer owned utilities are not purchasing REC's at this time. It is believed that REC's from the wind industry have met and exceeded the utility demand for near term interim targets.

Unbundled REC's When sold separately from the electricity, REC's are considered unbundled. They can be transacted anywhere in the WECC region and in British Columbia, Alberta, and a small part of Mexico. Unbundled REC's are purchased in two ways in Oregon. The Energy Trust of Oregon (ETO) purchases REC's from renewable energy power producers through an upfront construction incentive that is based upon the above market cost of their project. Other brokers, such as Bonneville Environmental Foundation, or utilities purchase REC's from Oregon renewable energy developers.

Unbundled REC's to ETO Biomass-to-energy incentives provided by ETO are based on a project's above market costs. There is no cap or fixed percentage of the amount of above-market costs the Energy Trust will pay. In return for the contribution, they require a negotiated share of the project's REC's green tags, which are held in trust for the ratepayers who contribute to ETO. The above market cost are those capital expenses that make the return on the project investment exceed the amount recovered from electricity sales to either Pacific Power or Portland General Electric, at their contracted avoided cost rates, over the 20 year life of the project or some other negotiated term.

For example a north central Oregon biomass facility planned a \$20 million expansion of 15 megawatts at their existing bio-energy facility. They received an above market cost offer from ETO of an up front payment of some \$5 million. The energy produced at that site over the 20 years was estimated at some 2.5 million megawatt hours (MWH) that would generate some 2.5 million REC's (1 MWH = 1,000 kilowatt hours, or one REC). That would place the value of that above market cost incentive traded REC at \$2. The analysis and calculation of the above market cost includes discounts of third party incentives such as federal renewable energy production tax credits or Oregon Business Energy Tax Credits.

ETO policy is to not claim all the REC's from a project. That would leave some REC's available for the owner of the renewable energy facility to sell in the open market.

Unbundled REC's to Third Parties Other organizations purchase WREGIS and Green-e® certified REC's in the open market.

In Oregon Bonneville Environmental Foundation (BEF) purchases REC's for resale, banking or retirement. All of BEF's RECs and carbon offsets are certified by the nation's leading, independent certification organizations including Green-e® and The Climate Action Reserve (CAR). In addition, BEF requires all RECs and carbon offsets also meet environmental impact and siting criteria set up by independent environmental organizations including the Natural Resources Defense Council.

A recent wind project REC purchase by BEF yielded a \$7.00 first year purchase price per REC (1 MWh) with a \$0.50 increase each year for a 20 year strip contract. There were a couple of pre-pay incentives in the agreement. The first year estimated production was paid up front to be trued up in the second year based on any under forecasted electricity production. Another payment once 10,000 MWh were produced.

The most recent inventory of the REC market and buyers by the U.S. Department of Energy is illustrated in the following table. It shows that the average market, through May of 2008, priced REC's at an approximate average value of \$2. With recent purchase prices climbing to the recently known purchase in Oregon at \$7.5, it can be assumed that using this 2010 price is conservative for a project with a start date in 2012.

National Retail REC Products (last updated May 2008)					
Certificate Marketer	Product Name	Renewable Resources	Location of Renewable Resources	Residential Price Premiums *	Certification
3 Phases Renewables	Green Certificates	100% biomass, geothermal, hydro, solar, wind	Nationwide	1.2¢/kWh	Green-e
3Degrees	Renewable Energy Certificates	100% new wind	Nationwide	1.5¢/kWh	Green-e
NativeEnergy	CooMatts	100% new wind	Nationwide	0.8¢/kWh	Green-e
NativeEnergy	Remooable Energy	100% new biogas	Pennsylvania	0.8¢/kWh-1.0¢/kWh	***
Bonneville Environmental Foundation	Solar Green Tags	100% new solar	Nationwide	5.6¢/kWh	Green-e
Bonneville Environmental Foundation	Wind & Solar Green Tags Blend	50% new wind, 50% new solar	Nationwide	2.4¢/kWh	Green-e
Bonneville Environmental Foundation	Wind Green Tags	100% wind	Nationwide	2.0¢/kWh	Green-e
Bonneville Environmental Foundation	Denali Green Tags (Alaska only)	100% new wind	10% Alaska, 90% Nationwide	2.0¢/kWh	Green-e
Bonneville Environmental Foundation	Zephyr Energy (Kansas Only)	50% new low-impact hydropower	Midwest, West	2.0¢/kWh	Green-e
Carbon Solutions	CSG	biomass, biogas,	Nationwide	0.9¢/kWh	Green-e

Group	CleanBuild wind, solar, hydro				
Carbonfund.org	MyGreenFuture	99% new wind, 1% new solar	Nationwide	0.5¢/kWh	Green-e
Choose Renewables	CleanWatts	100% new wind	Nationwide	1.7¢/kWh	Green-e
Community Energy	NewWind Energy	100% new wind	Nationwide	2.5¢/kWh	Green-e
Enpalo	US CleanGen	100% new wind	Nationwide	1.0¢/kWh	Green-e
Good Energy	Good Green RECs	various	Nationwide	0.4¢/kWh-1.5¢/kWh	Green-e
Green Mountain Energy	BeGreen RECs	wind, solar, biomass	Nationwide	1.4¢/kWh	—
Juice Energy	Positive Juice - Wind	100% wind	Nationwide	1.1¢/kWh	Green-e
MMA Renewable Ventures	PVUSA Solar Green Certificates	100% solar	California	3.3¢/kWh	Green-e
Maine Renewable Energy/Maine Interfaith Power & Light	Maine WindWatts	100% new wind	Maine	2.0¢/kWh	Green-e
Mass Energy Consumers Alliance	New England Wind Fund	100% new wind	New England	~5.0¢/kWh (donation)	—
Premier Energy Marketing	Premier 100% Wind REC	100% wind	Nationwide	0.95¢/kWh-2.0¢/kWh	Green-e
Renewable Choice Energy	American Wind	100% new wind	Nationwide	0.5¢/kWh	Green-e
SKY energy, Inc.	Wind-e Renewable Energy	100% new wind	Nationwide	2.4¢/kWh	Green-e

Santee Cooper	SC Green Power	landfill gas, solar	South Carolina	3.0¢/kWh	Green-e
Sky Blue Electric	Sky Blue 40	100% wind	Nationwide	4.2¢/kWh	Green-e
Sterling Planet	Sterling Wind	100% new wind	Nationwide	1.85¢/kWh	Green-e
TerraPass	Green-e RECs	100% new wind	Nationwide	0.5¢/kWh	Green-e
Village Green Energy	Village Green Power	solar, wind, biogas	California, Nationwide	2.0¢/kWh- 2.5¢/kWh	Green-e
Waverly Light & Power	Iowa Energy Tags	100% wind	Iowa	2.0¢/kWh	—
WindCurrent	Chesapeake Windcurrent	100% new wind	Mid-Atlantic States	2.5¢/kWh	Green-e
WindStreet Energy	Renewable Energy Credit Program	wind Nationwide		~1.2¢/kWh	—

Carbon Offset Credits

Purchase of carbon and other Green House Gas (GHG) offset credits in the United States is currently a voluntary market. There are various methods to certify a facility and register the credits for sale. There are Climate Reserve Tonnes (CRT's) from the Climate Action Reserve for carbon or methane in carbon equivalent credits. There are Certified Emission Reductions (CER's) through the Clean Development Mechanism (CDM), defined in Article 12 of the Kyoto Protocol.

For a 2 megawatt mixed waste digester to qualify for carbon offset credits or Climate Reserve Tonnes (CRT's) credits it must have qualified feedstocks and prove to be above standard market practice. At his time a digester using pre-consumer waste (rye straw, glycerine, food processor waste) or fats, oils and grease (FOG) as feedstock does not

meet CRT standards and protocols adopted 7 October 2009. Mixed waste stream Organic Waste Digesters (OWD) must prove that the feedstock would have otherwise gone to a landfill or an anaerobic lagoon for disposal. Approval of a portion of the waste stream that is qualified like commercial food service waste can be accomplished by petition. No CRT value is estimated for this project.

CRTs: California Air Resources Board (CARB) adopts voluntary GHG offset accounting protocols. CARB has adopted four voluntary GHG accounting protocols to encourage voluntary early action to reduce GHG emissions from sources activities such as business, industry, forestry or agriculture. These protocols were developed by the Climate Action Reserve (CAR), previously known as the California Climate Action Registry <http://www.climateactionreserve.org/> CAR has updated these protocols over time, and has used them for issuance of offset credits for the voluntary market. To the extent that these other GHG offset protocols influence electricity generation, WREGIS may adopt them for registry of eligible renewable electric energy facilities and REC's.

Mixed Organic Waste Digesters: The CAR Organic Waste Digestion (OWD) Project Protocol provides a GHG accounting methodology for GHG reduction projects that divert and anaerobically digest eligible organic waste and/or wastewater streams that otherwise would have gone to uncontrolled anaerobic storage, treatment and disposal systems such as solid waste landfills or on-site anaerobic wastewater treatment facilities. The protocol also addresses the co-digestion of eligible organic waste streams with livestock manure. This protocol was adopted by the Reserve Board 7 October 2009.

For the purpose of this protocol, a GHG reduction project (“project”) is defined as the digestion of one or more eligible organic waste and/or agro-industrial wastewater streams in an operational Biogas Control System that captures and destroys methane gas that would otherwise have been emitted to the atmosphere in the absence of the project. For the purposes of this protocol, a BCS is considered *operational* on the date at which the BCS begins destroying methane gas upon completion of a start-up period.

Projects that co-digest eligible organic waste streams together with manure also meet the definition of an OWD project. However, projects that digest manure without the addition of one or more eligible organic waste streams do not meet the definition of an OWD project and must use the Reserve's Livestock Project Protocol to register GHG reductions with the Reserve.

OWD projects may digest numerous potential feedstocks. The performance standard for this protocol defines those feedstocks that the Reserve has determined are highly likely to result in methane emissions under common practice or “business-as-usual” management practices. Only OWD projects that digest one of these feedstocks in a biogas control system are deemed to exceed common practice and are therefore eligible for registration under this protocol. An OWD project passes the Performance Standard Test only if one or more of the following eligible organic waste streams are consistently, periodically, or seasonally digested in the project's biogas control system:

- *Municipal Solid Waste (MSW) Food Waste*: Non-industrial food waste commonly disposed of in a MSW system, consisting of uneaten food, food scraps, spoiled food and food preparation wastes from homes, restaurants, kitchens, grocery stores, campuses, cafeterias, or similar institutions.
- *Agro-industrial Wastewater*: Organic loaded wastewater from industrial or agricultural processing operations that, prior to the project, was treated in an uncontrolled anaerobic lagoon, pond, or tank at a privately owned treatment facility. Excluded from eligibility based on the Reserve's performance standard analysis are wastewaters produced at breweries, ethanol plants, pharmaceutical production facilities, and pulp and paper plants.

Projects that co-digest organic waste together with manure must meet the OWD performance threshold as defined above to be eligible as an OWD project. Additionally, all livestock operations contributing manure to an OWD project must meet the eligibility requirements as defined in the most recent version (as of the time of project listing) of the Reserve's Livestock Project Protocol.

OWD projects may choose to digest multiple feedstocks, some of which may be ineligible per the Performance Standard Test. Ineligible waste streams, e.g. Fats Oils and Greases (FOG) residues and municipal biosolids (sludge), may be co-digested alongside eligible organic waste streams. However, any methane produced by these waste streams and destroyed by the project will not be eligible for crediting with Climate Reserve Tonnes (CRTs) by the Reserve.

Livestock Organic Waste Digesters: The CAR Livestock Project Protocol, version 2.2, was adopted 3 November 2009. This protocol requires installation of a biogas control system that captures and destroys methane gas from anaerobic manure treatment and/or storage facilities on livestock operations. The biogas control system must destroy methane gas that would otherwise have been emitted to the atmosphere in the absence of the project from uncontrolled anaerobic treatment and/or storage of manure. Captured biogas can be destroyed on-site, or transported for off-site use (e.g. through gas distribution or transmission pipeline), or used to power vehicles. Regardless of how project developers take advantage of the captured biogas, the ultimate fate of the methane must be destruction.

This protocol does not make allowance for mixed feedstock OWD to comply with this protocol. However, should a mixed feedstock OWD, meeting the protocols for everything but feedstock source, supplement that feedstock with manure from a confined animal feeding operation, that uses lagoons, that portion could be eligible for CRT's.

CER's: CDM allows a country with an emission-reduction or emission-limitation commitment under the Kyoto Protocol (Annex B Party) to implement an emission-reduction project in developing countries. Such projects can earn saleable certified

emission reduction (CER) credits, each equivalent to one tonne of CO₂, which can be counted towards meeting Kyoto targets.

A CDM project must provide emission reductions that are additional to what would otherwise have occurred. The projects must qualify through a rigorous and public registration and issuance process. Approval is given by the Designated National Authorities. Public funding for CDM project activities must not result in the diversion of official development assistance.

CDM allows a wide range of GHG reduction projects including energy efficiency, fuel switching, forestation, transportation, and renewable energy such as wind, solar, hydro, geothermal and waste biogas. The development and operation of qualified CDM projects produces CER's.

The Project Design Document (PDD) is prepared and submitted to the Designated Operational Entities (DOE), a third party verification and validation company accredited by the United Nations Framework Convention on Climate Change (UNFCCC). The PDD is developed using a specific format recommended by the CDM Executive Board, which includes a detailed description of the project, GHG emission reductions, baseline methodology, crediting period, monitoring methodology, environmental impacts, and stakeholder comments.

The CDM Executive Board, with regard to validation requirements to be checked by a designated operational entity, clarified that before entry into force of the Kyoto Protocol, all Parties to the Convention may participate in CDM project activities. In accordance with provisions of paragraphs 37 (a) and 40 (a) of the CDM modalities and procedures, the registration of a proposed CDM project activity can, however, only take place once approval letters are obtained from Parties to the Convention that have ratified the Kyoto Protocol.

Since the United States of America has not ratified and is not signatory to the Kyoto Protocol, nor a developing nation, there is no Designated National Authority for approving projects here for credits to be purchased by a developing nation. It is not likely a project built in the U.S. would qualify under these standards.

Verified Emission Reductions (VER's): Outside of Kyoto compliant mechanisms, other actions taken to reduce greenhouse gas emissions are being verified and traded in the global over-the-counter market for greenhouse gas emissions. These are categorized as Non-Kyoto Compliant Reductions. Some companies are trading emission reductions in other markets, since they fail to meet all the requirements or obligations under Kyoto for certification, such as, non-compliant with "additionality" or "leakage."

These "verified emission reductions" (VERs) are not a standardized commodity. VER's may eventually become CERs or Emission Reduction Units (ERUs) which are more tradable in secondary markets. However, many of these reductions have no secondary market benefits outside of their embedded "green image value" or speculative value. Buyers therefore tend to pay a discounted price for VERs, which takes the inherent regulatory risks into account.

Although there is no national mandated carbon offset program in the United States, various state and regional programs provide for the voluntary reduction of greenhouse gases and credit trading. There are several initiatives such as the Regional Greenhouse Gas Initiative (RGGI) being developed by nine north eastern states, or the recent California Global Warming Bill, and many other programs, such as, the Chicago Climate Exchange, and the California Climate Action Registry.

The Chicago Climate Exchange, is a member based exchange for voluntary GHG reductions, trading and registry for the United States. Carbon credits called Carbon Financial Instruments or CFIs, are registered under the Chicago Climate Exchange and traded amongst its registered member companies in the United States. Companies who fail to reduce their own emissions, can purchase credits from those who make extra emission cuts, or from verified offset projects. As of July 2006, more than 11.6 million metric tons were traded at prices between \$2.00-5.00 per metric ton.

Incentives to Business For Creating New Jobs in Oregon

Incentives to business creating new jobs in Oregon come in three forms, tax exemption, financing and employee training. The tax credits include income and property tax abatement available to businesses that provide and assure continuation of a pledged number of new jobs. Financing for capital and startup costs are either fixed term fixed rate or other loan term preferential loans through participating private lenders. There are a number of programs available. Employee training is in the form of an employer tax credit or matching grants for skills training through community colleges. There is little in the way of other grants to offset the capital cost for developing the new employment opportunities.

The incentives are both state and federal. You can get more information than is found in this summary at:

http://www.employmentincentives.com/state_incentives/Oregon/or_investment_advantage.htm

Oregon Enterprise Zone and Other Tax Exemption

Enterprise Zone requirements for the business to qualify for at least the three-year enterprise zone exemption are as follows:

- Increase full-time, permanent employment of the firm inside the enterprise zone by the greater of one new job or 10 percent
- No concurrent job losses more than 30 miles from the zone
- Maintain mandatory employment levels during exemption period
- Enter into first-source agreement with local job training providers
- Satisfy local additional conditions, potentially imposed in an urban enterprise zone.

The extended abatement of four or five consecutive years depends on:

- (1) “compensation” of new workers at 150 percent of county average wage,
- (2) a written agreement with the local zone sponsor, and
- (3) additional requirements that the local zone sponsor reasonably requests.

The Oregon Investment Advantage (OIA).

This program helps businesses start or locate new activities in Oregon. Companies setting up operations in a qualifying county are eligible for a 10-year waiver on all income/excise taxes related to those operations—potentially avoiding state business tax liability for that period.

Company must create at least five new full-time, year-round jobs; facility operations need to be the first of their kind in Oregon for that company and not compete within the local economy. The jobs created as a result of this program can go to qualified persons with disabilities who are seeking employment. Exemption of taxable income can be combined with an enterprise zone exemption on taxable property where available.

Financing Options

<http://www.oregon4biz.com/Business-financing-resources/Oregon-Finance-Programs/Oregon-Business-Development-Fund/>

Oregon Business Development Fund (OBDF).

The OBDF is a revolving loan fund that provides long-term fixed-rate financing for land, buildings, equipment, machinery and permanent working capital.

The fund emphasizes rural and distressed areas, and businesses with fewer than 100 employees. Participants must create or retain jobs and must be a traded-sector business in manufacturing, processing or a regionally significant tourist facility. The fund features a Targeted Development Account for distressed areas of Oregon.

Oregon Capital Access Program

This program helps lenders (banks) make more commercial loans to small businesses and provides capital for startup or expansion. CAP is designed for profit and nonprofit businesses seeking funds for most business purposes, except to purchase or improve residential housing or real property not used for business operations, or for refinancing an existing balance of a non-enrolled loan.

All types of loans and lines of credit are available. Lenders build a loan-loss reserve each time they provide a loan. Contributions to the loan-loss reserve account are matched by the state of Oregon.

Oregon Credit Enhancement Fund

Provides enrolled lenders with certain loan repayment guarantees for participants of the OBDF or CAP programs. Most local and regional banks in Oregon are enrolled.

Entrepreneurial Development Loan Fund

The Entrepreneurial Development Loan Fund provides initial direct loans to help companies get started in Oregon. This fund:

- assists micro-enterprise and small businesses;
- fills a niche not provided through traditional lending markets; and
- offers small-business counseling.

Participants must meet two of the following three criteria:

- Be in operation for less than 36 months
- Have revenues of less than \$175,000 in the previous 12 months
- Be a business owned by a severely disabled person

Business Retention Program (BRP).

This program provides consulting services to assist Oregon companies facing difficult times. The program offers companies consulting services that are delivered by some of the best and most experienced private sector consultants in the state. A consultant is matched with a company based on specific needs and industry requirements. The maximum benefits are \$5,000 for consulting services and \$30,000 for feasibility studies. In addition, to qualify for a feasibility study, the applicant must contribute 25 percent of the feasibility cost in cash.

Businesses must meet the following criteria to be eligible for Oregon Business Retention Program services:

- Be an Oregon company
- Be a company facing a period of hardship, such as financial or organizational distress
- Be willing to fully disclose its financial status to the consultant

If eligible, the business must complete an application form, participate in a brief qualification review process and, sign a service contract if approved for the program.

Employee Based Programs

New Employee Training

Oregon Governors Workforce Training Fund Or Governors Strategic Training Funds provide grants to offset the cost of the training of new employees needing skill upgrades for the work. This is administered through Community Colleges and is typically a 50% matching grant that is paid directly to the college on the businesses behalf.

Work Opportunity Tax Credits

This federal tax credit program is for businesses employing qualified target group members. It can reduce an employer's federal income tax liability. At the end of the tax year, the employer claims a credit of up to \$2,400 for most WOTC certified new hires.

This is based on 40 percent of up to \$6,000 of qualified first-year wages paid to those employed 400 hours or more. For certified employees that worked at least 120 hours but less than 400 hours, the tax credit is 25 percent of wages paid up to a maximum of \$6,000.

A maximum of \$4,800 in tax credit may be claimed on each WOTC certified disabled veteran, which is based on 40 percent of up to \$12,000 of qualified first-year wages paid on those employed 400 hours or more.

An employer may claim up to \$9,000 in tax credit for every WOTC certified long-term family assistance recipient. This is based on 40 percent of up to \$10,000 of qualified wages paid during the first year and 50 percent of up to \$10,000 paid in the second year for qualified long-term family assistance recipients employed 400 hours or more in each year.

Note: A new hire that is a previous employee, dependent, or relative of the employer cannot qualify the employer for the tax credit. Additional questions concerning how the credit could affect your federal taxes can be answered by an accountant or the Internal Revenue Service.

Target groups

- Temporary Assistance for Needy Families (TANF) recipients
- Veterans (recent food stamp recipients and qualified disabled veterans)
- Recently convicted or released ex-felons
- Vocational Rehabilitation referrals/Ticket-to-Work holders
- Food Stamp (FS) recipients 18 through 39 years of age
- Supplemental Security Income (SSI) recipients
- Disconnected Youth 16 through 24 years of age (added by ARRA 2009)
- Unemployed Veterans (Added by ARRA 2009)
- Long-term family assistance recipients

<http://www.doleta.gov/business/Incentives/opptax/>

http://www.oregon.gov/EMPLOY/ES/BUS/tax_incentive_programs.shtml

Sources of Private Equity

Historically, renewable energy project developers have used project - level debt, in the form of tax equity and bank loans, to finance their projects.

The Great Recession has had a negative impact on private investments in renewable energy. Renewable energy funding was down in 2009 from 2008 from all of the private funding sources. Given the current state of the credit markets, banks and other renewable energy lenders are unable to provide the same level of financing to the industry. Despite no changes in the project - level cash flows, lenders are now sizing their tranches on much more stringent terms, depressing the overall level of financing.

For the first three months of 2010, there has been an improvement in renewable energy funding from almost all of the private sources of money. This has been led by government incentives that have lowered the amount of private funds needed to finance a project.

The main sources of funding for renewable energy are as follows:

Sources of Renewable Energy Funding

Government

- ◆ Grants & Loans
- ◆ Incentives & Tax Credits
- ◆ Universities and Laboratories - Recipients of the lion's share of federal research and development dollars. They provide access to advanced technologies through technology transfer offices.
- ◆ Corporate Investors – Historically they have provided the leading share of capital for commercializing technologies developed at federal laboratories. For profit motives, invest at the pre-seed stage as they shop for new technologies to enhance their processes or launch new products.
- ◆ Seed Funds - Seed funds are professionally managed investment partnerships or limited liability companies (LLCs) that invest in very young, seed-stage companies.
- ◆ Angel Investors –Individual Investors – an affluent individual who provides capital for a business start-up, usually in exchange for convertible debt or ownership equity.
- ◆ Venture Funds – Institutional investors - long-term equity capital invested in rapidly expanding enterprises with an expectation of significant capital gains, often for product rollout. Typical investee companies have demonstrated sales, but are not yet profitable.
- ◆ Banks – Traditionally banks have made loans to companies that in their mature growth stage.

- ◆ **Utilities** – Utilities will often buy energy production projects once they are completed. In recent years, utilities have offered new and developing projects Power Purchase Agreements that have been used by project developers to secure construction funding.

Investments are made into companies at various stages of a company's life. The stages and their definitions are as follows:

- ◆ **R&D Capital** – funds invested in support of basic research and product/service development.
- ◆ **Pre-Seed Capital** – funds invested in support of applied research with the aim of developing new products.
- ◆ **Seed Capital** – funds invested in young companies that have not yet fully established commercial operations, often to launch new products, and may involve continued research and product development.
- ◆ **Venture Capital** – funds invested in exchange for equity in the company. Venture capital firms often want a high rate of return (20%+) and will finance the business with \$500,000 to millions. A venture capitalist differs from an angel investor in terms of wanting greater control of company and quicker return on investment.
- ◆ **Mezzanine Capital** – funds invested for unsecured debt (no collateral is required). The tradeoff is a high interest rate, in the 20- 30 percent range. Lender has the right to convert the debt into equity in the company if the company defaults on payments.
- ◆ **Secured Debt** – funds invested for secured debt, with the promise to return the principal, in addition to an agreed-upon level of interest . In addition, some type of collateral is required, usually business equipment or property.

The following chart, shows the basic forms of capital, the providers of the capital and the stages of development when providers invest in that capital. As can be seen in the chart, the forms of capital are complementary and often blend together, and may even be used simultaneously to meet the capital needs of a company.

The following sections detail the top funders by funding source, and the elements funders are looking for in an investment.

Government

Stimulus investment and tax credits from the U.S. government has boosted clean tech, with \$2.3 billion going to 183 clean tech manufacturing projects in 43 states, according to the report. Venture-backed projects got \$402 million.

Specific types of government funding that this project would be eligible are contained in the government funding section later in this plan.

Corporate Investors

In the corporate space, direct investments announced during 1st Quarter 2010 increased by 140 percent quarter over quarter compared to 4th Quarter 2009, primarily by energy and consumer and industrial products companies. Significant investments in biomass and wind projects were announced by Royal Dutch Shell, General Motors, Google and Valero Energy.

Traditionally, corporate investors have invested in projects that were heavy in research and development and had the opportunity for very large potential revenue, over \$100 million.

However, in 2010 corporate investors did invest in projects that had potential revenue of \$10 million.

Corporate invest is also done to off-set taxable income, by investing in projects that provide them tax credits. Overall though, reduced taxable income for corporations has resulted in tax credit investments being greatly reduced.

Corporate investments in biomass energy projects announced in 2009 and 2010 all involved waste streams of the corporation. These included announcements of projects by Recology, Waste Management and Walmart.

Seed Funds

Seed funds are usually composed of a group of angel investors who pool their money to invest together.

Seed funds generally invest in local companies. The funds are motivated by returns, but also community development and to mentor local entrepreneurs.

Seed investments are traditionally not publically announced, so there is little detail regarding the amount or type of seed investment made in to renewable energy projects.

Angel Capital Association estimates there were almost 8,000 seed fund investments totaling \$7.5 billion made in 2009. The ACA does not break these investments down by category type.

Angel Investors

Angel investors are the primary source of start-up and early-stage capital. The Angel Capital Association is North America's professional alliance of angel groups. The association brings together many of the angel organizations in the United States and Canada to share best practices and collaboration opportunities

According to the Angel Capital Association, Angels invest in companies for the following reasons:

- ◆ Have an interest and knowledge in a particular business sector, often the industry in which he or she has gained personal wealth;
- ◆ Can accommodate the smaller financing needs of start-up companies;
- ◆ Feel they can help a start-up company with their considerable experience.

The following is a list of angel groups in the Pacific Northwest.

- [Alliance of Angels](#) - Seattle, WA
- [Bellingham Angel Group](#) - Bellingham, WA
- [Boise Angel Alliance](#) - Boise, ID
- Columbia Investor Group - Spokane, WA
- [Delta Angel Group](#) - Spokane, WA
- [Keiretsu Forum - Bellevue/Eastside](#) - Bellevue, WA

- [Keiretsu Forum - Boise](#) - Boise, ID
- [Keiretsu Forum - Portland](#) - Portland, OR
- [Keiretsu Forum Seattle/Northwest](#) - Seattle, WA
- [Northwest Angel Network Inc](#) - Boise, ID
- [Northwest Energy Angels](#) - Maple Valley, WA
- [Oregon Angel Fund](#) - Portland, OR
- [Oregon Sustainability Angels](#) - OR
- [Portland Angel Network](#) - Portland, OR
- Portland Venture Group - Lake Oswego, OR
- [Puget Sound Venture Club](#) - Bellevue, WA
- [Seraph Capital Forum](#) - Seattle, WA
- [Southern Oregon Angel Network](#) - Medford, OR
- [Southern Willamette Angel Network](#) - Eugene, OR
- [Tacoma Angel Network](#) - Tacoma, WA
- [Women's Investment Network](#) - Portland, OR
- [ZINO Society](#) - Seattle, WA

Venture Funds

Though it is the best known source of capital investment, venture capital plays almost no role in funding basic innovation, and a relatively small role in funding true start-ups. Generally, VCs only invest in high-growth business sectors where they can see a return on their investment in 5 years or less.

Among the items that VC's invest in companies for:

- ♦ Business sectors which are growing rapidly & have not yet reached the competitive shakeout stage.
- ♦ 5-year Exit Strategy
- ♦ Minimum 10x Return on Investment
- ♦ Proven project team

Most Active Cleantech Venture Investors: 1Q 2010

Venture Capital Firm	# of rounds	Companies
Draper Fisher Jurvetson	5	Genomatica, Konarka Technologies, Power Assure, Prudent Energy, Scientific Conservation
Braemar Energy Ventures	3	Ciris Energy, Enerkem, Luminus Devices
Carbon Trust Investments	3	AeroThermal, Marine Current Turbines, Oxsensis

Foundation Capital	3	Azure Power, CalStar Products, Purfresh
Good Energies	3	Agile Energy, Konarka Technologies, Nexamp
Intel Capital	3	Cymbet Corporation, SpectraWatt
Nth Power	3	CalStar Products, Propel Biofuels, Tempronics
Rho Ventures	3	Ciris Energy, Coulomb Technologies, Enerkem
Sequoia Capital	3	Achates Power, Prudent Energy
VantagePoint Venture Partners	3	Acura Technologies, Better Place, Ze-gen

Source: Cleantech Group (cleantech.com)

Other Notable Cleantech Venture Funds

[Kleiner Perkins Caufield & Byers \(KPCB\)](#)

Northwest/Oregon Based Cleantech Venture Funds

[OVP Venture Partners VII \(Oregon\)](#)

[Riverlake Partners \(Oregon\)](#)

[Smart Forest Ventures \(Oregon\)](#)

[Tamarack Mezzanine Partners \(Oregon\)](#)

[Buerk Dale Victor II \(Washington\)](#)

Banks

A bank loan for a renewable energy project is secured by the assets of the project and is sized based on the project's projected cash flows. (Banks may also secure the debt with other assest of the project developer including their house and other properties they own).

In the past, bank's loaned up to 80% of the cost of a piece of equipment. More recently that number has dropped to 50%.

According to a survey conducted by the federal reserve and released May 4, 2010, most U.S. banks maintained tight restrictions on most types of loans to businesses and consumers over the past three months, making it difficult for borrowers to obtain credit.

The survey said that banks began tightening lending standards in 2007 and haven't let up since. Banks tighten standards in several ways: raising thresholds for credit scores, reducing credit limits, shortening maturities, charging higher interest payments and fees, requiring higher minimum payments, or requiring greater collateral.

The Fed reported that the volume of outstanding commercial and industrial loans at commercial banks had declined 19% over the past year. Access to financing outside of commercial banks also remains impaired, with the commercial paper market down 21% in the past year.

Small businesses continued to find credit hard to obtain, the Fed survey said. Just 2% of banks said they had loosened standards for commercial and industrial loans to small businesses, equal to the percentage that tightened standards further.

In a special question in this quarter's survey, 70% of banks said their standards for business credit card accounts for small businesses were stricter than usual, with 27% saying their standards were unchanged.

Several banks in the Pacific Northwest have made loans to renewable energy projects.

These include:

- ◆ Umpqua Bank
- ◆ Bank of the Cascades
- ◆ Shoreline Bank

Equipment Leasing

In addition, banks and leasing companies will lease equipment to renewable energy projects

In a lease arrangement, the capital equipment is owned by the lease company and is used by a project. The project pays a monthly fee for the use of the equipment. The leasing company takes the tax credits and depreciation for a five-year term, and they claim any tax credits.

At the end of the lease term, the energy project can buy the equipment for a lump sum based on the fair market price of the depreciated equipment. Currently, the lease residual payment at the end of the 5 years is approximately 15% of the new equipment price. Because there is no ownership of the equipment capital expenses are drastically reduced. Without the equipment on the books as assets there is a reduced owner benefit of depreciation for tax purposes. The equipment financier will handle and control the equipment from purchase to installation, and cover all placements cost and commissioning.

Banks in the Pacific Northwest that are interested in renewable energy project leasing include:

- Bank of the West

Federal Loan Guarantee Program for Banks

For renewable energy projects, both the US Department of Energy and the US Department of Agriculture over banks a guarantee of up to 80 percent of a loan made for a project.

The DOE program is for projects that are unable to obtain conventional private sector financing due to technology risks and projects that are unable to obtain private loans due to the credit crisis, including projects that do not employ innovative technology.

The term of the loan may be up to the lesser of 30 years or 90 percent of the projected useful life of project assets.

Upon reaching agreement with a borrower on terms for the project loan, the Lender-Applicant will apply to DOE for a guarantee of up to 80 percent of that loan.

(The federal guarantee programs are discussed in more detail in the government incentive section).

Utilities

Total capacity additions announced by utilities increased in 1Q 2010 compared to 4Q 2009, as government incentives spurred spending on the part of companies. In the U.S., Wind and Solar PV remained the most attractive energy sources for utilities due to extended tax credits.

Typically, in small renewable energy project, those under 9.9MW, a developer will sell the power from the project to a utility and retain ownership of the project.

Interconnection and Power Purchase for Small Capacity

Renewable Resources in Oregon

The Oregon Public Utility Commission regulates standard power purchase agreement conditions, with investor owned utilities in Oregon. Bonneville Power Administration and consumer owned utility standard agreements with qualified facilities generally follow similar format and address the same agreement elements. The elements in standard firm power purchase agreements in Oregon address the following:

Recital defines the seller's intent, capacity of the generation system, and the utilities intent.

Definitions explain the terms used throughout the agreement. They describe the meanings of the terms as they pertain to that specific agreement. Definitions across various utility agreements are generally universal.

Term and Commercial Operation Date specifies the start of energy and power delivery from the power producer and the length of time the agreement is in force.

Representations and Warranties the assurances and limits of warrantee provided by and to each party. It addresses the limits to which the power producer may accept liens and encumbrance. The minimum and maximum annual energy delivery to the point of delivery and the term of the generation interconnection agreement are agreed to. It requires the power producer to warrant that the facility will produce nameplate capacity, and operate within the standards of a net dependable generation facility that complies with prudent electrical practices.

Delivery of Power sets forth the minimum power delivery assurance (typically 75% of nameplate). It addresses that the power producer has elected to the power purchase rates and terms. Conditions for delivery of power less than the net minimum are specified. Agreement to provide the utility supplemental definition of the as-built system are also conditions of this section.

Contract Price specifies the power seller's choice of rate that the utility agrees to pay over the term of the agreement. Options include a fixed price contract that usually escalates over the term based upon the utilities supply mix forecasted avoided cost. Other price options include specific gas supply price indexes. Those may include a dead band index an agreed upon gas index price or an index at a certain gas marketing location such as Mid C or Henry Hub.

Operation and Control defines the obligation of the power producer to meet minimum standards for operations and controls at the facility. It identifies the conditions for notification of scheduled or unscheduled shut down. It alleviates the utility from the obligation to purchase power should the facility be operated outside safe or prudent generation practice or outside the terms and conditions of the interconnection agreement. This section obligates the power producer to resume generation as soon as

safely possible after unscheduled shutdown regardless of progress on annual net delivery agreements.

Creditworthiness requires the power producer to agree that should their liabilities affect delivery or warranties or the power producer's solvency to notify the utility and accept an escrow, step in, cash or senior lien position request by the utility.

Metering allows the utility to install, operate, maintain and test the metering of power produced as specified in the generation interconnection agreement at the power producer's cost.

Billings, computations and payments define the terms for billing and payment of costs agreed. Payment delivery (usually net 30 days) and interest rate on any payments owed past the due date are agreed to.

Default remedies and termination set out the conditions for determining default, the options for reconciliation or termination of the agreement. The roles and responsibilities of the parties are defined under default circumstances.

Indemnification and liability usually creates severalty between the power producer and the purchasing utility. This excludes the utility from liabilities associated with the power producer's operations of the facility regarding finance obligations, human resource liabilities, or other aspects of conducting business to produce power for sale to the utility. Likewise, it excludes the power producer from any negligence on behalf of the utility or any other liabilities owing to the utility from its other delivery of power to consumers. It exempts any parties not signatory to the agreement from having rights under the agreement.

Insurance defines the insurance requirements of the utility placed upon the power producer. General liability of \$1 million per incident is usually required. It further obligates the power producer to repair damaged, destroyed or ineffective equipment either through insurance or equity financing and allows the utility to terminate the agreement should the facility be substantially destroyed such as to effect non-delivery under the agreement.

Force Majeure can be referred to as an act of god or other conditions which are outside of the control of either the utility or the power producer and describe the actions required by the parties. It defines the roles, responsibilities, terms and conditions of alleviating either party under these circumstances. It further defines the resolution of any failure to perform under the agreement by either party.

Severall obligations simply stipulates that the parties are not in partnership in any way and that the agreement is a conditional sale and purchase relationship.

Partial invalidity and PURPA repeal specifies that the intent of the parties is to follow utility regulatory law and to comply with it should it change.

Governmental and jurisdictional authorizations address the parties' role in compliance with other outside governmental authorities.

Successors and assigns makes the agreement between the signatory power producer and the utility and that no assignment of rights or obligations can be made under the agreement without the other parties acknowledgement and subsequent agreement.

Entire agreement states that the agreement supersedes any previous similar purpose agreements between the parties. It requires that any amendment or modification of the agreement shall be agreed to in writing by both parties.

Notices specifies that all communication regarding the rights or obligations under the agreement and specifies their certified delivery through the U.S. Postal Service.

Signatories the power purchasing utilities signing authority and the authorized legal representative of the power producer are required to sign the agreement and it requires witnesses.

Interconnection Agreement Samples

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms shall have the following meanings:

1.1 “**As-built Supplement**” shall be a supplement to **Exhibit A** and **Exhibit B**, provided by Seller following completion of construction of the Facility, describing the Facility as actually built.

1.2 “**Average Annual Generation**” shall have the meaning set forth in Section 4.2.

1.3 “**Billing Period**” means calendar months.

1.4 “**Commercial Operation Date**” means the date that the Facility is deemed by PacifiCorp to be fully operational and reliable, which shall require, among other things, that all of the following events have occurred:

1.4.1 PacifiCorp has received a certificate addressed to PacifiCorp from a Licensed Professional Engineer stating (a) the Facility Capacity Rating of the Facility at the anticipated Commercial Operation Date; and (b) that the Facility is able to generate electric power reliably in amounts required by this Agreement and in accordance with all other terms and conditions of this Agreement;

1.4.2 The Facility has completed Start-Up Testing (applies to new Facilities and new upgrades only);

1.4.3 PacifiCorp has received a certificate addressed to PacifiCorp from an attorney in good standing in the State of Oregon stating that Seller has obtained all Required Facility Documents (Facilities over 200 kW only) and, if requested by PacifiCorp, in writing, has provided copies of any or all such requested Required Facility Documents.

1.4.4 Seller has complied with the security requirements of Section 10.

1.4.5 PacifiCorp has received an executed copy of **Exhibit F** - Seller’s Interconnection Request.

1.5 “**Commission**” means the Oregon Public Utilities Commission.

1.6 “**Contract Price**” means the applicable price for Net Output stated in Sections 5.1 and 5.2.

1.7 “**Contract Year**” means a twelve (12) month period commencing at 00:00 hours Pacific Prevailing Time (“**PPT**”) on January 1 and ending on 24:00 hours PPT on

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December 31; *provided, however*, that the first Contract Year shall commence on the Commercial Operation Date and end on the next succeeding December 31, and the last Contract Year shall end on the Termination Date.

1.8 “**Credit Requirements**” means a long-term credit rating (corporate or long-term senior unsecured debt) of (1) “Baa3” or greater by Moody’s, or (2) “BBB-” or greater by S&P, or such other indicia of creditworthiness acceptable to PacifiCorp in its reasonable judgment.

1.9 “**Default Security**”, unless otherwise agreed to by the Parties in writing, means the amount of either a Letter of Credit or cash placed in an escrow account sufficient to replace twelve (12) average months of replacement power costs over the term of this Agreement, and shall be calculated by taking the average, over the term of this Agreement, of the positive difference between (a) the monthly forward power prices at _____ **[specify POD]** (as determined by PacifiCorp in good faith using information from a commercially reasonable independent source), multiplied by 110%, minus (b) the average of the Fixed Avoided Cost Prices specified in Schedule 37, and multiplying such difference by (c) the Minimum Annual Delivery; provided, however, the amount of Default Security shall in no event be less than the amount equal to the payments PacifiCorp would make for three (3) average months based on Seller’s average monthly volume over the term of this Agreement and utilizing the average Fixed Avoided Cost Prices specified in Schedule 37. Such amount shall be fixed at the Effective Date of this Agreement.

1.10 “**Effective Date**” shall have the meaning set forth in Section 2.1.

1.11 “**Energy Delivery Schedule**” shall have the meaning set forth in Section 4.5.

1.12 “**Environmental Attributes**” shall have the meaning set forth in Section 5.5.

1.13 “**Excess Output**” shall mean any increment of Net Output produced at a rate, on an hourly basis, exceeding the Facility Capacity Rating.

1.14 “**Facility**” shall have the meaning set forth in Recital A.

1.15 “**Facility Capacity Rating**” means the sum of the Nameplate Capacity Ratings for all generators comprising the Facility.

1.16 “**FERC**” means the Federal Energy Regulatory Commission, or its successor.

1.17 “**Generation Scheduling Addendum**” means **Addendum W**, the portion of this Agreement providing for the measurement, scheduling, and delivery of Net Output from the Facility to the Point of Delivery via a non-PacifiCorp transmission provider.

1.18 “**Interconnected Utility**” means _____, the operator of the electric utility system at the Point of Interconnection.

1.19 “**Interconnection Agreement**” means the agreement (or contemporaneous agreements) between Seller and the Interconnected Utility governing interconnection of

Interconnection Agreement Samples

Seller's Facility at the Point of Interconnection and associated use of the Interconnected Utility's system.

1.20 “**Letter of Credit**” means an irrevocable standby letter of credit, from an institution that has a long-term senior unsecured debt rating of “A” or greater from S&P or “A2” or greater from Moody's, in a form reasonably acceptable to PacifiCorp, naming PacifiCorp as the party entitled to demand payment and present draw requests thereunder.

1.21 “**Licensed Professional Engineer**” means a person acceptable to PacifiCorp in its reasonable judgment who is licensed to practice engineering in the state of Oregon, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer shall be licensed in an appropriate engineering discipline for the required certification being made.

1.22 “**Material Adverse Change**” means the occurrence of any event of default under any material agreement to which Seller is a party and of any other development, financial or otherwise, which would have a material adverse effect on Seller, the Facility or Seller's ability to develop, construct, operate, maintain or own the Facility as provided in this Agreement

1.23 “**Maximum Annual Delivery**” shall have the meaning set forth in Section 4.3.

1.24 “**Minimum Annual Delivery**” shall have the meaning set forth in Section 4.3.

1.25 “**Nameplate Capacity Rating**” means the full-load electrical quantities assigned by the designer to a generator and its prime mover or other piece of electrical equipment, such as transformers and circuit breakers, under standardized conditions, expressed in amperes, kilovoltamperes, kilowatts, volts, or other appropriate units. Usually indicated on a nameplate attached to the individual machine or device.

1.26 “**Net Energy**” means the energy component, in kWh, of Net Output.

1.27 “**Net Output**” means all energy and capacity produced by the Facility, less station use and less transformation and transmission losses and other adjustments (e.g., Seller's load other than station use), if any, up to and including the Point of Interconnection. For purposes of calculating payment under this Agreement, Net Output of energy shall be the amount of energy flowing through the Point of Interconnection, less any station use not provided by the Facility.

1.28 “**Net Replacement Power Costs**” shall have the meaning set forth in Section 11.4.1.

1.29 “**Off-Peak Hours**” means all hours of the week that are not On-Peak Hours.

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1.30 “**On-Peak Hours**” means the hours between 6 a.m. Pacific Prevailing Time (“**PPT**”) and 10 p.m. PPT, Mondays through Saturdays, excluding all hours occurring on holidays as provided in Schedule 37.

1.31 “**Point of Delivery**” means the location in PacifiCorp’s system where PacifiCorp has agreed to receive Seller’s Net Energy, as specified in **Exhibit B**.

1.32 “**Point of Interconnection**” means the point of interconnection between Seller’s Facility and the Transmitting Entity’s system, if applicable, as specified in **Exhibit B**.

1.33 “**Prime Rate**” means the publicly announced prime rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate shall be the announced prime rate for commercial loans in effect from time to time quoted by a bank with \$10 billion or more in assets in New York City, New York, selected by the Party to whom interest based on the Prime Rate is being paid.

1.34 “**Prudent Electrical Practices**” means any of the practices, methods and acts engaged in or approved by a significant portion of the electrical utility industry or any of the practices, methods or acts, which, in the exercise of reasonable judgment in the light of the facts known at the time a decision is made, could have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition. Prudent Electrical Practices is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be a spectrum of possible practices, methods or acts.

1.35 “**QF**” means “**Qualifying Facility**,” as that term is defined in the FERC regulations (codified at 18 CFR Part 292) in effect on the Effective Date.

1.36 “**Replacement Price**” means the price at which PacifiCorp, acting in a commercially reasonable manner, purchases for delivery at the Point of Delivery a replacement for any Net Output that Seller is required to deliver under this Agreement plus (i) costs reasonably incurred by PacifiCorp in purchasing such replacement Net Output, and (ii) additional transmission charges, if any, reasonably incurred by PacifiCorp in causing replacement energy to be delivered to the Point of Delivery. If PacifiCorp elects not to make such a purchase, the Replacement Price shall be the market price at the Mid-Columbia trading hub for such energy not delivered, plus any additional cost or expense incurred as a result of Seller’s failure to deliver, as determined by PacifiCorp in a commercially reasonable manner (but not including any penalties, ratcheted demand or similar charges).

1.37 “**Required Facility Documents**” means all licenses, permits, authorizations, and agreements, including an Interconnection Agreement and Transmission Agreement(s), necessary for construction, operation and maintenance of the Facility, and delivery of Facility output, consistent with the terms of this Agreement. The Required Facility Documents are set forth in **Exhibit C**.

1.38 “**Schedule 37**” means the Schedule 37 of Pacific Power & Light Company’s Commission-approved tariffs, providing pricing options for Qualifying Facilities of 10,000 kW

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or less, which is in effect on the Effective Date of this Agreement. A copy of that Schedule 37 is attached as **Exhibit G**.

1.39 “**Scheduled Commercial Operation Date**” shall have the meaning set forth in Recital C.

1.40 “**Scheduled Initial Delivery Date**” shall have the meaning set forth in Recital B.

1.41 “**Start-Up Testing**” means the completion of required factory and start-up tests as set forth in **Exhibit E** hereto.

1.42 “**Termination Date**” shall have the meaning set forth in Section 2.4.

1.43 “**Transmission Agreement**” means the agreement (or contemporaneous agreements) between Seller and the Transmitting Entity providing for Seller’s uninterrupted right to transmit Net Output to the Point of Delivery.

1.44 “**Transmitting Entity(s)**” means _____, the (non-PacifiCorp) operator of the transmission system at the Point of Delivery.

SECTION 2: TERM; COMMERCIAL OPERATION DATE

2.1 This Agreement shall become effective after execution by both Parties (“**Effective Date**”).

2.2 **Time is of the essence for this Agreement**, and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to deliver Net Output by the Scheduled Commercial Operation Date is critically important. Therefore,

2.2.1 By _____, Seller shall provide PacifiCorp with a copy of an executed Interconnection Agreement and an executed Transmission Agreement, which shall be consistent with all material terms and requirements of this Agreement.

2.2.2 Upon completion of construction, Seller, in accordance with Section 6.1, shall provide PacifiCorp with an As-built Supplement acceptable to PacifiCorp;

2.2.3 By the date thirty (30) days after the Effective Date, Seller shall provide Default Security required under Sections 10.1 or 10.2, as applicable.

2.3 Seller shall cause the Facility to achieve Commercial Operation on or before the Scheduled Commercial Operation Date. If Commercial Operation occurs after the Scheduled Commercial Operation Date, Seller shall be in default, and liable for delay damages specified in Section 11.

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2.4 Except as otherwise provided herein, this Agreement shall terminate on _____ [enter Date that is no later than 20 years after the Scheduled Initial Delivery Date] (“**Termination Date**”).

SECTION 3: REPRESENTATIONS AND WARRANTIES

- 3.1 PacifiCorp represents, covenants, and warrants to Seller that:
- 3.1.1 PacifiCorp is duly organized and validly existing under the laws of the State of Oregon.
 - 3.1.2 PacifiCorp has the requisite corporate power and authority to enter into this Agreement and to perform according to the terms of this Agreement.
 - 3.1.3 PacifiCorp has taken all corporate actions required to be taken by it to authorize the execution, delivery and performance of this Agreement and the consummation of the transactions contemplated hereby.
 - 3.1.4 The execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on PacifiCorp or any valid order of any court, or any regulatory agency or other body having authority to which PacifiCorp is subject.
 - 3.1.5 This Agreement is a valid and legally binding obligation of PacifiCorp, enforceable against PacifiCorp in accordance with its terms (except as the enforceability of this Agreement may be limited by bankruptcy, insolvency, bank moratorium or similar laws affecting creditors’ rights generally and laws restricting the availability of equitable remedies and except as the enforceability of this Agreement may be subject to general principles of equity, whether or not such enforceability is considered in a proceeding at equity or in law).
- 3.2 Seller represents, covenants, and warrants to PacifiCorp that:
- 3.2.1 Seller is a [corporation, partnership, or limited liability company] duly organized and validly existing under the laws of _____.
 - 3.2.2 Seller has the requisite power and authority to enter into this Agreement and to perform according to the terms hereof, including all required regulatory authority to make wholesale sales from the Facility.
 - 3.2.3 Seller has taken all actions required to authorize the execution, delivery and performance of this Agreement and the consummation of the transactions contemplated hereby.

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- 3.2.4 The execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Seller or any valid order of any court, or any regulatory agency or other body having authority to which Seller is subject.
- 3.2.5 This Agreement is a valid and legally binding obligation of Seller, enforceable against Seller in accordance with its terms (except as the enforceability of this Agreement may be limited by bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies and except as the enforceability of this Agreement may be subject to general principles of equity, whether or not such enforceability is considered in a proceeding at equity or in law).
- 3.2.6 The Facility is and shall for the term of this Agreement continue to be a QF, and Seller will operate the Facility in a manner consistent with its FERC QF certification. Seller has provided to PacifiCorp the appropriate QF certification (which may include a FERC self-certification) prior to PacifiCorp's execution of this Agreement. At any time during the term of this Agreement, PacifiCorp may require Seller to provide PacifiCorp with evidence satisfactory to PacifiCorp in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements and, if PacifiCorp is not satisfied that the Facility qualifies for such status, a written legal opinion from an attorney who is (a) in good standing in the state of Oregon, and (b) who has no economic relationship, association or nexus with the Seller or the Facility, stating that the Facility is a QF and providing sufficient proof (including copies of all documents and data as PacifiCorp may request) demonstrating that Seller has maintained and will continue to maintain the Facility as a QF.
- 3.2.7 Compliance with Partial Stipulation in Commission Proceeding No. UM-1129. Seller will not make any changes in its ownership, control, or management during the term of this Agreement that would cause it to not be in compliance with the definition of a Small Cogeneration Facility or Small Power Production Facility provided in PacifiCorp's Schedule 37 tariff approved by the Commission at the time this Agreement is executed. Seller will provide, upon request by PacifiCorp not more frequently than every 36 months, such documentation and information as reasonably may be required to establish Seller's continued compliance with such Definition. PacifiCorp agrees to take reasonable steps to maintain the confidentiality of any portion of the above-described documentation and information that the Seller identifies as confidential except PacifiCorp will provide all such confidential information the Public Utility Commission of Oregon upon the Commission's request.

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3.2.8 Additional Seller Creditworthiness Warranties. Seller need not post security under Section 10 for PacifiCorp's benefit in the event of Seller default, provided that Seller warrants all of the following:

- (a) Neither the Seller nor any of its principal equity owners is or has within the past two (2) years been the debtor in any bankruptcy proceeding, is unable to pay its bills in the ordinary course of its business, or is the subject of any legal or regulatory action, the result of which could reasonably be expected to impair Seller's ability to own and operate the Facility in accordance with the terms of this Agreement.
- (b) Seller has not at any time defaulted in any of its payment obligations for electricity purchased from PacifiCorp.
- (c) Seller is not in default under any of its other agreements and is current on all of its financial obligations, including construction related financial obligations.
- (d) Seller owns, and will continue to own for the term of this Agreement, all right, title and interest in and to the Facility, free and clear of all liens and encumbrances other than liens and encumbrances related to third-party financing of the Facility.
- (e) **[Applicable only to Sellers with a Facility having a Facility Capacity Rating greater than 3,000 kW]** Seller meets the Credit Requirements.

Seller hereby declares (Seller initial one only):

_____ Seller affirms and adopts all warranties of this Section 3.2.8, and therefore is not required to post security under Section 10; or

_____ Seller does not affirm and adopt all warranties of this Section 3.2.8, and therefore Seller elects to post the security specified in Section 10.

3.3 Notice. If at any time during this Agreement, any Party obtains actual knowledge of any event or information which would have caused any of the representations and warranties in this Section 3 to have been materially untrue or misleading when made, such Party shall provide the other Party with written notice of the event or information, the representations and warranties affected, and the action, if any, which such Party intends to take to make the representations and warranties true and correct. The notice required pursuant to this Section shall be given as soon as practicable after the occurrence of each such event.

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SECTION 4: DELIVERY OF POWER

4.1 Commencing on the Commercial Operation Date, unless otherwise provided herein, Seller will sell and PacifiCorp will purchase all Net Output from the Facility delivered to the Point of Delivery.

4.2 Average Annual Generation. Seller estimates that the Facility will generate, on average, _____ kWh per Contract Year (“**Average Annual Generation**”). Seller may, upon at least six months prior written notice, modify the Average Annual Generation every other Contract Year.

4.3 Minimum and Maximum Delivery. Seller shall deliver (or cause to be delivered) from the Facility a minimum of _____ kWh of Net Output during each Contract Year, provided that such minimum for the first Contract Year shall be reduced *pro rata* to reflect the Commercial Operation Date, and further provided that such minimum delivered Net Output shall be reduced on a *pro rata* basis for any periods during a Contract Year that the Facility was prevented from generating or delivering electricity for reasons of Force Majeure (“**Minimum Annual Delivery**”). Seller estimates, for informational purposes, that it will deliver from the Facility a maximum of _____ kWh of Net Output during each Contract Year (“**Maximum Annual Delivery**”). Seller’s basis for determining the Minimum and Maximum Annual Delivery amounts is set forth in **Exhibit D**.

4.4 Deliveries in Deficit of Delivery Obligation. Seller’s failure to deliver the Minimum Annual Delivery in any Contract Year (prorated if necessary) shall be a default, and Seller shall be liable for damages in accordance with Section 11.

4.5 Energy Delivery Schedule. Seller has provided a monthly schedule of Net Energy expected to be delivered by the Facility (“**Energy Delivery Schedule**”), incorporated into **Exhibit D**.

SECTION 5: PURCHASE PRICES

5.1 Seller shall have the option to select one of four pricing options: Fixed Avoided Cost Prices (“Fixed Price”), Firm Market Indexed Avoided Cost Prices (“Firm Electric Market”), Gas Market Indexed Avoided Cost Prices (“Gas Market”), or Banded Gas Market Indexed Avoided Cost Prices (“Banded Gas Market”), as published in Schedule 37. Once an option is selected the option will remain in effect for the duration of the Facility’s contract. Seller has selected the following (Seller to initial one):

- _____ Fixed Price
- _____ Firm Electric Market
- _____ Gas Market
- _____ Banded Gas Market

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A copy of Schedule 37, and a table summarizing the purchase prices under the pricing option selected by Seller, is attached as **Exhibit G**.

5.2 (Applies only to “Fixed Price” Contracts Greater than 15 Years). In the event Seller elects the Fixed Price payment method, PacifiCorp shall pay Seller the applicable On-Peak and Off-Peak rates specified in **Schedule 37** during the first fifteen (15) years after the Scheduled Initial Delivery Date. Thereafter, PacifiCorp shall pay Seller market-based rates, using the following pricing option (Seller to initial one):

- _____ Firm Electric Market
- _____ Gas Market
- _____ Banded Gas Market

5.3 If the Seller elects a gas market indexed price option, the index shall be the Opal Gas Market Index as provided in Schedule 37. In the event that Platt ceases to publish the Opal Gas Market Index, the Company shall replace the index with a similar gas index.

5.4 For all Excess Output and for all Net Output delivered prior to the Commercial Operation Date, PacifiCorp shall pay Seller a blended market index price for day-ahead non-firm energy at Mid-Columbia, California Oregon Border (COB), Four Corners and Palo Verde market indices as reported by Dow Jones, for the On-Peak and Off-Peak periods. PacifiCorp shall document its calculation of the blended rate, upon request, to Seller. Such payment will be accomplished by adjustments pursuant to Section 9.2.

5.5 Environmental Attributes. PacifiCorp waives any claim to Seller’s ownership of Environmental Attributes under this Agreement. Environmental Attributes include, but are not limited to, Green Tags, Green Certificates, Renewable Energy Credits (RECs) and Tradable Renewable Certificates (TRCs) (as those terms are commonly used in the regional electric utility industry) directly associated with the production of energy from the Seller’s Facility.

SECTION 6: OPERATION AND CONTROL

6.1 As-Built Supplement. Upon completion of initial (and any subsequent) construction affecting the Facility, Seller shall provide PacifiCorp an As-built Supplement to specify the actual Facility as built. The As-built Supplement must be reviewed and approved by PacifiCorp, which approval shall not unreasonably be withheld, conditioned or delayed.

6.2 Incremental Utility Upgrades. At start-up (and at any other time upon at least six month’s prior written notice), Seller may increase Net Output, if such increase is due to normal variances in estimated versus actual performance, changed Facility operations, or improvements in Facility efficiency. Seller may not increase Net Output under this Agreement by installing additional generating units. In the case of substantial upgrades, PacifiCorp may require Seller to comply with Section 3.2.8(e) (in the event that the Facility upgrade causes the Facility Capacity Rating to exceed 3,000 kW) and increase its Minimum Annual Delivery obligation in Section 4.3 (if appropriate). PacifiCorp may also update Seller’s security obligation (if applicable). So long as the Facility Capacity Rating after the upgrade is 10,000

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kW or less, Seller will continue to receive the Contract Price for the Net Output, as set forth in Sections 5.1 and 5.2 of this Agreement. If Seller increases the Facility Capacity Rating above 10,000 kW, then (on a going forward basis) PacifiCorp shall pay Seller the Contract Price for the fraction of total Net Output equal to 10,000 kW divided by the Facility Capacity Rating of the upgraded Facility. For the remaining fraction of Net Output, PacifiCorp and Seller shall agree to a new negotiated rate. Seller shall be responsible for ensuring that any planned increase in the Facility Capacity Rating or the maximum instantaneous capacity of the Facility complies with Seller's Interconnection Agreement, Transmission Agreement and any other relevant agreements.

6.3 Seller shall operate and maintain the Facility in a safe manner in accordance with this Agreement, the Interconnection Agreement, Prudent Electrical Practices and in accordance with the requirements of all applicable federal, state and local laws and the National Electric Safety Code as such laws and code may be amended from time to time. PacifiCorp shall have no obligation to purchase Net Output from the Facility to the extent the interconnection between the Facility and the Point of Delivery is disconnected, suspended or interrupted, in whole or in part, pursuant to the Interconnection Agreement or Transmission Agreement(s), or to the extent generation curtailment is required as a result of Seller's non-compliance with the Interconnection Agreement or Transmission Agreement(s). PacifiCorp shall have the right to inspect the Facility to confirm that Seller is operating the Facility in accordance with the provisions of this Section 6.3 upon reasonable notice to Seller. Seller is solely responsible for the operation and maintenance of the Facility. PacifiCorp shall not, by reason of its decision to inspect or not to inspect the Facility, or by any action or inaction taken with respect to any such inspection, assume or be held responsible for any liability or occurrence arising from the operation and maintenance by Seller of the Facility.

6.4 Scheduled Outages. Seller may cease operation of the entire Facility or individual units, if applicable, for maintenance or other purposes. Seller shall exercise its best efforts to notify PacifiCorp of planned outages at least ninety (90) days prior, and shall reasonably accommodate PacifiCorp's request, if any, to reschedule such planned outage in order to accommodate PacifiCorp's need for Facility operation.

6.5 Unplanned Outages. In the event of an unscheduled outage or curtailment exceeding twenty-five (25) percent of the Facility Capacity Rating (other than curtailments due to lack of motive force), Seller immediately shall notify PacifiCorp of the necessity of such unscheduled outage or curtailment, the time when such has occurred or will occur and the anticipated duration. Seller shall take all reasonable measures and exercise its best efforts to avoid unscheduled outage or curtailment, to limit the duration of such, and to perform unscheduled maintenance during Off-Peak hours.

SECTION 7: FUEL/MOTIVE FORCE

Prior to the Effective Date of this Agreement, Seller provided to PacifiCorp a fuel or motive force plan acceptable to PacifiCorp in its reasonable discretion and attached hereto as **Exhibit D-1**, together with a certification from a Licensed Professional Engineer to PacifiCorp attached hereto as **Exhibit D-2**, certifying that the implementation of the fuel or motive force plan can

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reasonably be expected to provide fuel or motive force to the Facility for the duration of this Agreement adequate to generate power and energy in quantities necessary to deliver the Minimum Annual Delivery set forth by Seller in Section 4.

SECTION 8: METERING AT THE POINT OF INTERCONNECTION

8.1 Metering shall be performed at the location and in a manner consistent with this Agreement, as specified in **Exhibit B**. Seller shall provide to PacifiCorp metered Facility Net Output in hourly increments, and any other energy measurements required to administer this Agreement. If the Transmitting Entity requires Seller to telemeter data, PacifiCorp shall be entitled to receive the same data Seller provides to the Transmitting Entity, if such data is useful to PacifiCorp's administration of this Agreement. All quantities of energy purchased hereunder shall be adjusted to account for electrical losses, if any, between the point of metering and the Point of Interconnection. The loss adjustment shall be ___% of the kWh energy production recorded on the Facility output meter.

8.2 Seller shall pay for the installation, testing, and maintenance of any metering required by Section 8.1, and shall provide reasonable access to such meters. PacifiCorp shall have reasonable access to inspection, testing, repair and replacement of the metering equipment. If any of the inspections or tests discloses a measurement error exceeding two percent (2%), either fast or slow, proper correction, based upon the inaccuracy found, shall be made of previous readings for the actual period during which the metering equipment rendered inaccurate measurements if that period can be ascertained. If the actual period cannot be ascertained, the proper correction shall be made to the measurements taken during the time the metering equipment was in service since last tested, but not exceeding three (3) Billing Periods, in the amount the metering equipment shall have been shown to be in error by such test. Any correction in billings or payments resulting from a correction in the meter records shall be made in the next monthly billing or payment rendered following the repair of the meter.

SECTION 9: BILLINGS, COMPUTATIONS, AND PAYMENTS

9.1 On or before the thirtieth (30th) day following the end of each Billing Period, PacifiCorp shall send to Seller payment for Seller's deliveries of Net Output to PacifiCorp, together with computations supporting such payment. PacifiCorp may offset any such payment to reflect amounts owing from Seller to PacifiCorp pursuant to this Agreement or any other agreement between the Parties.

9.2 Corrections. PacifiCorp shall have up to eighteen months to adjust any payment made pursuant to Section 9.1. In the event PacifiCorp determines it has overpaid Seller (for Excess Output or otherwise), PacifiCorp may adjust Seller's future payment accordingly in order to recapture any overpayment in a reasonable time.

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9.3 Any amounts owing after the due date thereof shall bear interest at the Prime Rate plus two percent (2%) from the date due until paid; *provided, however*, that the interest rate shall at no time exceed the maximum rate allowed by applicable law.

SECTION 10: SECURITY

Unless Seller has adopted the creditworthiness warranties contained in Section 3.2.8, Seller must provide security (if requested by PacifiCorp) in the form of a cash escrow, letter of credit, senior lien, or step-in rights. Seller hereby elects to provide, in accordance with the applicable terms of this Section 10, the following security (Seller to initial one selection only):

- _____ Cash Escrow
- _____ Letter of Credit
- _____ Senior Lien
- _____ Step-in Rights
- _____ Seller has adopted the Creditworthiness Warranties of Section 3.2.8.

In the event Seller's obligation to post default security (under Section 10 or Section 11.1.4) arises solely from Seller's delinquent performance of construction-related financial obligations, upon Seller's request, PacifiCorp will excuse Seller from such obligation in the event Seller has negotiated financial arrangements with its construction lenders that mitigate Seller's financial risks to PacifiCorp's reasonable satisfaction.

[SKIP THIS SECTION 10.1 UNLESS SELLER SELECTED CASH ESCROW ALTERNATIVE]

10.1 Cash Escrow Security. Seller shall deposit in an escrow account established by PacifiCorp in a banking institution acceptable to both Parties, the Default Security. Such sum shall earn interest at the rate applicable to money market deposits at such banking institution from time to time. To the extent PacifiCorp receives payment from the Default Security, Seller shall, within fifteen (15) days, restore the Default Security as if no such deduction had occurred.

[SKIP THIS SECTION 10.2 UNLESS SELLER SELECTED LETTER OF CREDIT ALTERNATIVE]

10.2 Letter of Credit Security. Seller shall post and maintain in an amount equal to the Default Security: (a) a guaranty from a party that satisfies the Credit Requirements, in a form acceptable to PacifiCorp in its discretion, or (b) a Letter of Credit in favor of PacifiCorp. To the extent PacifiCorp receives payment from the Default Security, Seller shall, within fifteen (15) days, restore the Default Security as if no such deduction had occurred.

[SKIP THIS SECTION 10.3 UNLESS SELLER SELECTED SENIOR LIEN ALTERNATIVE]

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10.3 Senior Lien. Before the Scheduled Commercial Operation Date, Seller shall grant PacifiCorp a senior, unsubordinated lien on the Facility and its assets as security for performance of this Agreement by executing, acknowledging and delivering a security agreement and a deed of trust or a mortgage, in a recordable form (each in a form satisfactory to PacifiCorp in the reasonable exercise of its discretion). Pending delivery of the senior lien to PacifiCorp, Seller shall not cause or permit the Facility or its assets to be burdened by liens or other encumbrances that would be superior to PacifiCorp's, other than workers', mechanics', suppliers' or similar liens, or tax liens, in each case arising in the ordinary course of business that are either not yet due and payable or that have been released by means of a performance bond posted within eight (8) calendar days of the commencement of any proceeding to foreclose the lien.

[SKIP THIS SECTION 10.4 UNLESS SELLER SELECTED STEP-IN RIGHTS ALTERNATIVE]

10.4 Step-in Rights (Operation by PacifiCorp Following Event of Default of Seller).

10.4.1 Prior to any termination of this Agreement due to an Event of Default of Seller, as identified in Section 11, PacifiCorp shall have the right, but not the obligation, to possess, assume control of, and operate the Facility as agent for Seller (in accordance with Seller's rights, obligations, and interest under this Agreement) during the period provided for herein. Seller shall not grant any person, other than the lending institution providing financing to the Seller for construction of the Facility ("Facility Lender"), a right to possess, assume control of, and operate the Facility that is equal to or superior to PacifiCorp's right under this Section 10.4.

10.4.2 PacifiCorp shall give Seller ten (10) calendar days notice in advance of the contemplated exercise of PacifiCorp's rights under this Section 10.4. Upon such notice, Seller shall collect and have available at a convenient, central location at the Facility all documents, contracts, books, manuals, reports, and records required to construct, operate, and maintain the Facility in accordance with Prudent Electrical Practices. Upon such notice, PacifiCorp, its employees, contractors, or designated third parties shall have the unrestricted right to enter the Facility for the purpose of constructing and/or operating the Facility. Seller hereby irrevocably appoints PacifiCorp as Seller's attorney-in-fact for the exclusive purpose of executing such documents and taking such other actions as PacifiCorp may reasonably deem necessary or appropriate to exercise PacifiCorp's step-in rights under this Section 10.4.

10.4.3 During any period that PacifiCorp is in possession of and constructing and/or operating the Facility, no proceeds or other monies attributed to operation of the Facility shall be remitted to or otherwise provided to the account of Seller until all Events of Default of Seller have been cured.

10.4.4 During any period that PacifiCorp is in possession of and operating the Facility, Seller shall retain legal title to and ownership of the Facility and

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PacifiCorp shall assume possession, operation, and control solely as agent for Seller.

- (a) In the event PacifiCorp is in possession and control of the Facility for an interim period, Seller shall resume operation and PacifiCorp shall relinquish its right to operate when Seller demonstrates to PacifiCorp's reasonable satisfaction that it will remove those grounds that originally gave rise to PacifiCorp's right to operate the Facility, as provided above, in that Seller (i) will resume operation of the Facility in accordance with the provisions of this Agreement, and (ii) has cured any Events of Default of Seller which allowed PacifiCorp to exercise its rights under this Section 10.4.
- (b) In the event that PacifiCorp is in possession and control of the Facility for an interim period, the Facility Lender, or any nominee or transferee thereof, may foreclose and take possession of and operate the Facility and PacifiCorp shall relinquish its right to operate when the Facility Lender or any nominee or transferee thereof, requests such relinquishment.

10.4.5 PacifiCorp's exercise of its rights hereunder to possess and operate the Facility shall not be deemed an assumption by PacifiCorp of any liability attributable to Seller. If at any time after exercising its rights to take possession of and operate the Facility PacifiCorp elects to return such possession and operation to Seller, PacifiCorp shall provide Seller with at least fifteen (15) calendar days advance notice of the date PacifiCorp intends to return such possession and operation, and upon receipt of such notice Seller shall take all measures necessary to resume possession and operation of the Facility on such date.

SECTION 11: DEFAULTS AND REMEDIES

11.1 Events of Default. The following events shall constitute defaults under this Agreement:

- 11.1.1 Breach of Material Term. Failure of a Party to perform any material obligation imposed upon that Party by this Agreement (including but not limited to failure by Seller to meet any deadline set forth in Section 2) or breach by a Party of a representation or warranty set forth in this Agreement.
- 11.1.2 Default on Other Agreements. Seller's failure to cure any default under any commercial or financing agreements or instrument (including the Interconnection Agreement and any Transmission Agreement) within the time allowed for a cure under such agreement or instrument.

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- 11.1.3 Insolvency. A Party (a) makes an assignment for the benefit of its creditors; (b) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy or similar law for the protection of creditors, or has such a petition filed against it and such petition is not withdrawn or dismissed within sixty (60) days after such filing; (c) becomes insolvent; or (d) is unable to pay its debts when due.
- 11.1.4 Material Adverse Change. A Material Adverse Change has occurred with respect to Seller and Seller fails to provide such performance assurances as are reasonably requested by PacifiCorp, including without limitation the posting of additional Default Security, within thirty (30) days from the date of such request;
- 11.1.5 Delayed Commercial Operations. Seller's failure to achieve the Commercial Operation Date by the Scheduled Commercial Operation Date.
- 11.1.6 Underdelivery. If Seller's Facility has a Facility Capacity Rating of 100 kW or less, Seller's failure to satisfy the minimum delivery obligation of Section 4.3 for two (2) consecutive years; else Seller's failure to satisfy the minimum delivery obligation of Section 4.3 for one year.
- 11.2 Notice; Opportunity to Cure.
- 11.2.1 Notice. In the event of any default hereunder, the non-defaulting Party must notify the defaulting Party in writing of the circumstances indicating the default and outlining the requirements to cure the default.
- 11.2.2 Opportunity to Cure. A Party defaulting under Section 11.1.1 or 11.1.5 shall have thirty (30) days to cure after receipt of proper notice from the non-defaulting Party. This thirty (30) day period shall be extended by an additional ninety (90) days if (a) the failure cannot reasonably be cured within the thirty (30) day period despite diligent efforts, (b) the default is capable of being cured within the additional ninety (90) day period, and (c) the defaulting Party commences the cure within the original thirty (30) day period and is at all times thereafter diligently and continuously proceeding to cure the failure.
- 11.2.3 Seller Default Under Other Agreements. Seller shall cause any notices of default under any of its commercial or financing agreements or instruments to be sent by the other party to such agreements or instruments, or immediately forwarded, to PacifiCorp as a notice in accordance with Section 23.
- 11.2.4 Seller Delinquent on Construction-related Financial Obligations. Seller promptly shall notify PacifiCorp (or cause PacifiCorp to be notified) anytime it becomes delinquent under any construction related financing

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agreement or instrument related to the Facility. Such delinquency may constitute a Material Adverse Change, subject to Section 11.1.4.

11.3 Termination.

11.3.1 Notice of Termination. If a default described herein has not been cured within the prescribed time, above, the non-defaulting Party may terminate this Agreement at its sole discretion by delivering written notice to the other Party and may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement; *provided, however* that PacifiCorp shall not terminate: (a) for a default under Section 11.1.5 unless PacifiCorp is in a resource deficient state during the period Commercial Operation is delayed; or (b) for a default under Section 11.1.6, unless such default is material. The rights provided in Section 10 and this Section 11 are cumulative such that the exercise of one or more rights shall not constitute a waiver of any other rights. Further, the Parties may by mutual written agreement amend this Agreement in lieu of a Party's exercise of its right to terminate.

11.3.2 In the event this Agreement is terminated because of Seller's default and Seller wishes to again sell Net Output to PacifiCorp following such termination, PacifiCorp in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price, until the Termination Date (as set forth in Section 2.4). At such time Seller and PacifiCorp agree to execute a written document ratifying the terms of this Agreement.

11.3.3 Damages. If this Agreement is terminated as a result of Seller's default, Seller shall pay PacifiCorp the positive difference, if any, obtained by subtracting the Contract Price from the sum of the Replacement Price for the Minimum Annual Delivery that Seller was otherwise obligated to provide for a period of twenty-four (24) months from the date of termination plus any cost incurred for transmission purchased to deliver the replacement power to the Point of Delivery, and the estimated administrative cost to the utility to acquire replacement power. Amounts owed by Seller pursuant to this paragraph shall be due within five (5) business days after any invoice from PacifiCorp for the same.

11.3.4 If this Agreement is terminated because of Seller's default, PacifiCorp may foreclose upon any security provided pursuant to Section 10 to satisfy any amounts that Seller owes PacifiCorp arising from such default.

11.4 Damages.

11.4.1 Failure to Deliver Net Output. In the event of Seller default under Subsection 11.1.5 or Subsection 11.1.6, then Seller shall pay PacifiCorp the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price for any energy and capacity that Seller was

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otherwise obligated (under Section 4.3) to provide during the period of default (“**Net Replacement Power Costs**”); *provided, however*, that the positive difference obtained by subtracting the Contract Price from the Replacement Price shall not exceed the Contract Price, and the period of default under this Section 11.4.1 shall not exceed one Contract Year.

11.4.2 Recoupment of Damages.

- (a) Default Security Available. If Seller has posted Default Security, PacifiCorp may draw upon that security to satisfy any damages, above.
- (b) Default Security Unavailable. If Seller has not posted Default Security, or if PacifiCorp has exhausted the Default Security, PacifiCorp may collect any remaining amount owing by partially withholding future payments to Seller over a reasonable period of time, which period shall not be less than the period over which the default occurred. PacifiCorp and Seller shall work together in good faith to establish the period, and monthly amounts, of such withholding so as to avoid Seller’s default on its commercial or financing agreements necessary for its continued operation of the Facility.

SECTION 12: INDEMNIFICATION AND LIABILITY

12.1 Indemnities.

12.1.1 Indemnity by Seller. Seller shall release, indemnify and hold harmless PacifiCorp, its directors, officers, agents, and representatives against and from any and all loss, fines, penalties, claims, actions or suits, including costs and attorney’s fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with (a) the energy delivered by Seller under this Agreement to and at the Point of Delivery, (b) any facilities on Seller’s side of the Point of Delivery, (c) Seller’s operation and/or maintenance of the Facility, or (d) arising from this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PacifiCorp, Seller or others, excepting only such loss, claim, action or suit as may be caused solely by the fault or gross negligence of PacifiCorp, its directors, officers, employees, agents or representatives.

12.1.2 Indemnity by PacifiCorp. PacifiCorp shall release, indemnify and hold harmless Seller, its directors, officers, agents, Lenders and representatives against and from any and all loss, fines, penalties, claims, actions or suits, including costs and attorney’s fees, both at trial and on appeal, resulting

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from, or arising out of or in any way connected with the energy delivered by Seller under this Agreement after the Point of Delivery, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property, excepting only such loss, claim, action or suit as may be caused solely by the fault or gross negligence of Seller, its directors, officers, employees, agents, Lenders or representatives.

12.2 No Dedication. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PacifiCorp as an independent public utility corporation or Seller as an independent individual or entity.

12.3 No Consequential Damages. EXCEPT TO THE EXTENT SUCH DAMAGES ARE INCLUDED IN THE LIQUIDATED DAMAGES, DELAY DAMAGES, COST TO COVER DAMAGES OR OTHER SPECIFIED MEASURE OF DAMAGES EXPRESSLY PROVIDED FOR IN THIS AGREEMENT, NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR SPECIAL, PUNITIVE, INDIRECT, EXEMPLARY OR CONSEQUENTIAL DAMAGES, WHETHER SUCH DAMAGES ARE ALLOWED OR PROVIDED BY CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY, STATUTE OR OTHERWISE.

SECTION 13: INSURANCE (FACILITIES OVER 200KW ONLY)

13.1 Certificates. Prior to connection of the Facility to PacifiCorp's electric system, or another utility's electric system, Seller shall secure and continuously carry insurance in compliance with the requirements of this Section. Seller shall provide PacifiCorp insurance certificate(s) (of "ACORD Form" or the equivalent) certifying Seller's compliance with the insurance requirements hereunder. Commercial General Liability coverage written on a "claims-made" basis, if any, shall be specifically identified on the certificate. If requested by PacifiCorp, a copy of each insurance policy, certified as a true copy by an authorized representative of the issuing insurance company, shall be furnished to PacifiCorp.

13.2 Required Policies and Coverages. Without limiting any liabilities or any other obligations of Seller under this Agreement, Seller shall secure and continuously carry with an insurance company or companies rated not lower than "B+" by the A.M. Best Company the insurance coverage specified below:

13.2.1 Commercial General Liability insurance, to include contractual liability, with a minimum single limit of \$1,000,000 to protect against and from all loss by reason of injury to persons or damage to property based upon and arising out of the activity under this Agreement.

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13.2.2 All Risk Property insurance providing coverage in an amount at least equal to the full replacement value of the Facility against "all risks" of physical loss or damage, including coverage for earth movement, flood, and boiler and machinery. The Risk policy may contain separate sub-limits and deductibles subject to insurance company underwriting guidelines. The Risk Policy will be maintained in accordance with terms available in the insurance market for similar facilities.

13.3 The Commercial General Liability policy required herein shall include i) provisions or endorsements naming PacifiCorp, its Board of Directors, Officers and employees as additional insureds, and ii) cross liability coverage so that the insurance applies separately to each insured against whom claim is made or suit is brought, even in instances where one insured claims against or sues another insured.

13.4 All liability policies required by this Agreement shall include provisions that such insurance is primary insurance with respect to the interests of PacifiCorp and that any other insurance maintained by PacifiCorp is excess and not contributory insurance with the insurance required hereunder, and provisions that such policies shall not be canceled or their limits of liability reduced without 1) ten (10) days prior written notice to PacifiCorp if canceled for nonpayment of premium, or 2) thirty (30) days prior written notice to PacifiCorp if canceled for any other reason.

13.5 Insurance coverage provided on a "claims-made" basis shall be maintained by Seller for a minimum period of five (5) years after the completion of this Agreement and for such other length of time necessary to cover liabilities arising out of the activities under this Agreement.

SECTION 14: FORCE MAJEURE

14.1 As used in this Agreement, "**Force Majeure**" or "**an event of Force Majeure**" means any cause beyond the reasonable control of the Seller or of PacifiCorp which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of fuel or motive force resources to operate the Facility or changes in market conditions that affect the price of energy or transmission. If either Party is rendered wholly or in part unable to perform its obligation under this Agreement because of an event of Force Majeure, that Party shall be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the event of Force Majeure, after which such Party shall re-commence performance of such obligation, provided that:

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- 14.1.1 the non-performing Party, shall, within two (2) weeks after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and
- 14.1.2 the suspension of performance shall be of no greater scope and of no longer duration than is required by the event of Force Majeure; and
- 14.1.3 the non-performing Party uses its best efforts to remedy its inability to perform.

14.2 No obligations of either Party which arose before the Force Majeure causing the suspension of performance shall be excused as a result of the event of Force Majeure.

14.3 Neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

14.4 PacifiCorp may terminate the Agreement if Seller fails to remedy Seller's inability to perform, due to an event of Force Majeure, within six months after the occurrence of the event.

SECTION 15: SEVERAL OBLIGATIONS

Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party shall be jointly and severally liable for Seller's obligations under this Agreement.

SECTION 16: CHOICE OF LAW

This Agreement shall be interpreted and enforced in accordance with the laws of the State of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

SECTION 17: PARTIAL INVALIDITY

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement shall remain in effect. If any terms are finally held or determined to be invalid, illegal or void, the Parties shall enter into negotiations concerning the terms affected by such decision for the purpose of achieving conformity with requirements of any applicable law and the intent of the Parties to this Agreement.

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SECTION 18: WAIVER

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement must be in writing, and such waiver shall not be deemed a waiver with respect to any subsequent default or other matter.

SECTION 19: GOVERNMENTAL JURISDICTIONS AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. Seller shall at all times maintain in effect all local, state and federal licenses, permits and other approvals as then may be required by law for the construction, operation and maintenance of the Facility, and shall provide upon request copies of the same to PacifiCorp.

SECTION 20: REPEAL OF PURPA

This Agreement shall not terminate upon the repeal of the PURPA, unless such termination is mandated by federal or state law.

SECTION 21: SUCCESSORS AND ASSIGNS

This Agreement and all of the terms hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties. No assignment hereof by either Party shall become effective without the written consent of the other Party being first obtained and such consent shall not be unreasonably withheld, conditioned or delayed. Notwithstanding the foregoing, either Party may assign this Agreement without the other Party's consent to a lender as part of a financing transaction or as part of (a) a sale of all or substantially all of the assigning Party's assets, or (b) a merger, consolidation or other reorganization of the assigning Party.

SECTION 22: ENTIRE AGREEMENT

22.1 This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding PacifiCorp's purchase of Net Output from the Facility. No modification of this Agreement shall be effective unless it is in writing and signed by both Parties.

22.2 By executing this Agreement, Seller releases PacifiCorp from any claims, known or unknown, that may have arisen prior to the Effective Date.

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SECTION 23: NOTICES

23.1 All notices except as otherwise provided in this Agreement shall be in writing, shall be directed as follows and shall be considered delivered if delivered in person or when deposited in the U.S. Mail, postage prepaid by certified or registered mail and return receipt requested.

Notices	PacifiCorp	Seller
All Notices	PacifiCorp 825 NE Multnomah Street Portland, OR 97232 Attn: Contract Administration, Suite 600 Phone: (503) 813 - 5952 Facsimile: (503) 813 - 6291 Duns: 00-790-9013 Federal Tax ID Number: 93-0246090	
All Invoices:	(same as street address above) Attn: Back Office, Suite 700 Phone: (503) 813 - 5578 Facsimile: (503) 813 – 5580	
Scheduling:	(same as street address above) Attn: Resource Planning, Suite 600 Phone: (503) 813 - 6090 Facsimile: (503) 813 – 6265	
Payments:	(same as street address above) Attn: Back Office, Suite 700 Phone: (503) 813 - 5578 Facsimile: (503) 813 – 5580	
Wire Transfer:	Bank One N.A. ABA: ACCT: NAME: PacifiCorp Wholesale	
Credit and Collections:	(same as street address above) Attn: Credit Manager, Suite 1900 Phone: (503) 813 - 5684 Facsimile: (503) 813 – 5609	
With Additional Notices of an Event of Default or Potential Event of Default to:	(same as street address above) Attn: PacifiCorp General Counsel Phone: (503) 813-5029 Facsimile: (503) 813-7252	

23.2 The Parties may change the person to whom such notices are addressed, or their addresses, by providing written notices thereof in accordance with this Section 23.

Interconnection Agreement Samples

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed in their respective names as of the date first above written.

PacifiCorp

Seller

By: _____

By: _____

Name: _____

Name: _____

Title: _____

Title: _____

Interconnection Agreement Samples

**EXHIBIT A
DESCRIPTION OF SELLER'S FACILITY**

[Seller to Complete]

Seller's Facility consists of _____ generators manufactured by _____ . More specifically, each generator at the Facility is described as:

A. Manufacturer's Nameplate Data:

Type (synchronous or inductive):

Model:

Number of Phases:

Rated Output (kW):

Rated Output (kVA):

Rated Voltage (line to line):

Rated Current (A): Stator: _____ A; Rotor: _____ A

Power factor requirements:

Rated Power Factor (PF) or reactive load (kVAR):

B. Seller's Estimate of Facility Output Under Ideal (Maximum) or Worst (Minimum) Conditions

Maximum kW Output: _____ kW **Maximum kVA Output:** _____ kVA

Minimum kW Output: _____ kW

Manufacturer's Guaranteed Cut-in Wind Speed [if applicable]:

Facility Capacity Rating: _____ kW at _____

Identify the maximum output of the generator(s) and describe any differences between that output and the Nameplate Capacity Rating:

Station service requirements, and other loads served by the Facility, if any, are described as follows:

_____.

C: Location of the Facility: The Facility is to be constructed in the vicinity of _____ in _____ County, _____. The location is more particularly described as follows:

[legal description of parcel]

Interconnection Agreement Samples

EXHIBIT B

SELLER'S INTERCONNECTION FACILITIES

[Seller to provide its own diagram and description]

POINT OF DELIVERY / SELLER'S INTERCONNECTION FACILITIES

Instructions to Seller:

1. Describe the point(s) of metering, including the type of meter(s), and the owner of the meter(s).
2. Provide single line diagram of Facility including station use meter, Facility output meter(s), Interconnection Facilities, Point of Interconnection,
3. Specify the Point of Delivery, and any transmission facilities on Seller's side of the Point of Delivery used to deliver Net Output.

Interconnection Agreement Samples

EXHIBIT C REQUIRED FACILITY DOCUMENTS

REQUIRED OF ALL FACILITIES:

- QF Certification
- Interconnection Agreement
- Fuel Supply Agreement, if applicable

REQUIRED IF SELLER ELECTS TO GRANT SENIOR LIEN OR STEP-IN RIGHTS:

- Deed or Lease to Facility Premises
- Preliminary Title Report of Premises
- Proof of ownership of Facility
- Off-take sale agreements, e.g. surplus heat sale contract, if applicable

Depending upon the type of Facility and its specific characteristics, additional Required Facility Documents may be requested.

Interconnection Agreement Samples

Interconnection Agreement Samples

EXHIBIT D-1 SELLER'S MOTIVE FORCE PLAN

A. MONTHLY DELIVERY SCHEDULES AND SCHEDULED MAINTENANCE

Month	Average Energy (kWh)
January	
February	
March	
April	
May	
June	
July	
August	
September	
October	
November	
December	

Seller provide an estimate of the average monthly Net Output of the Facility, and explain the basis for the estimate.

B. MINIMUM ANNUAL DELIVERY CALCULATION

Seller specify the Minimum Annual Delivery of the Facility, and explain the basis for the estimate. NOTE: The Minimum Annual Delivery should be based on the most adverse natural motive force conditions reasonably expected and should take into account unscheduled repairs or maintenance and Seller's load (if any).

C. MAXIMUM ANNUAL DELIVERY CALCULATION

Seller specify the estimated Maximum Annual Delivery of the Facility, and explain the basis for the estimate.

Interconnection Agreement Samples

EXHIBIT D-2 ENGINEER'S CERTIFICATION OF MOTIVE FORCE PLAN

Seller provide a written declaration from a Licensed Professional Engineer to PacifiCorp that the Facility is likely capable under average conditions foreseeable during the term of this Agreement of meeting Seller's estimated average, maximum, and minimum Net Output.

Interconnection Agreement Samples

EXHIBIT E

START-UP TESTING

Required factory testing includes such checks and tests necessary to determine that the equipment systems and subsystems have been properly manufactured and installed, function properly, and are in a condition to permit safe and efficient start-up of the Facility, which may include but are not limited to (as applicable): **[Seller identify appropriate tests]**

1. Pressure tests of all steam system equipment;
2. Calibration of all pressure, level, flow, temperature and monitoring instruments;
3. Operating tests of all valves, operators, motor starters and motor;
4. Alarms, signals, and fail-safe or system shutdown control tests;
5. Insulation resistance and point-to-point continuity tests;
6. Bench tests of all protective devices;
7. Tests required by manufacturer of equipment; and
8. Complete pre-parallel checks with PacifiCorp.

Required start-up tests are those checks and tests necessary to determine that all features and equipment, systems, and subsystems have been properly designed, manufactured, installed and adjusted, function properly, and are capable of operating simultaneously in such condition that the Facility is capable of continuous delivery into PacifiCorp's electrical system, which may include but are not limited to (as applicable):

1. Turbine/generator mechanical runs including shaft, vibration, and bearing temperature measurements;
2. Running tests to establish tolerances and inspections for final adjustment of bearings, shaft run-outs;
3. Brake tests;
4. Energization of transformers;
5. Synchronizing tests (manual and auto);
6. Stator windings dielectric test;
7. Armature and field windings resistance tests;
8. Load rejection tests in incremental stages from 5, 25, 50, 75 and 100 percent load;
9. Heat runs;
10. Tests required by manufacturer of equipment;
11. Excitation and voltage regulation operation tests;
12. Open circuit and short circuit; saturation tests;
13. Governor system steady state stability test;
14. Phase angle and magnitude of all PT and CT secondary voltages and currents to protective relays, indicating instruments and metering;
15. Auto stop/start sequence;
16. Level control system tests; and
17. Completion of all state and federal environmental testing requirements.

Interconnection Agreement Samples

EXHIBIT F

Seller Authorization to Release Generation Data to PacifiCorp

[Interconnection Customer Letterhead]

Transmission Services
Attn: Director, Transmission Services
825 NE Multnomah, Suite 1600
Portland, OR 97232

RE: _____ Interconnection Request

Dear Sir:

_____ hereby voluntarily authorizes PacifiCorp's Transmission business unit to share _____'s generator interconnection information and generator meter data with Marketing Affiliate employees of PacifiCorp Energy, including, but not limited to those in the Commercial and Trading group. _____ acknowledges that PacifiCorp did not provide it any preferences, either operational or rate-related, in exchange for this voluntary consent.

Name

Title

Date

Interconnection Agreement Samples

EXHIBIT G
SCHEDULE 37 and PRICING SUMMARY TABLE

Interconnection Agreement Samples
ADDENDUM W

GENERATION SCHEDULING ADDENDUM

WHEREAS, Seller's Facility is not located within the control area of PacifiCorp;

WHEREAS, Seller's Facility will not interconnect directly to PacifiCorp's System;

WHEREAS, Seller and PacifiCorp have not executed, and will not execute, a Generation Interconnection Agreement in conjunction with the Power Purchase Agreement;

WHEREAS, Seller has elected to exercise its right under PURPA to deliver Net Output from its QF Facility to PacifiCorp via one (or more) Transmitting Entities.

WHEREAS, PacifiCorp desires that Seller schedule delivery of Net Output on a firm, hourly basis;

WHEREAS, PacifiCorp does not intend to buy, and Seller does not intend to deliver, more or less than Net Output from the Facility (except as expressly provided, below);

THEREFORE, Seller and PacifiCorp do hereby agree to the following, which shall become part of their Power Purchase Agreement:

DEFINITIONS

The meaning of the terms defined in the Power Purchase Agreement and this **Addendum W** shall apply to this Generation Scheduling Addendum:

"Day" means midnight to midnight, prevailing local time at the Point of Delivery, or any other mutually agreeable 24-hour period.

"Energy Imbalance Accumulation," or **"EIA,"** means the accumulated difference between Seller's Net Output and the energy actually delivered at the Point of Delivery. A positive accumulated difference indicates Seller's net delivery of Supplemented Output to PacifiCorp.

"Firm Delivery" means uninterruptible transmission service that is reserved and/or scheduled between the Point of Interconnection and the Point of Delivery pursuant to Seller's Transmission Agreement.

"Settlement Period" means one month.

"Supplemented Output" means any increment of scheduled hourly energy or capacity delivered to the Point of Delivery in excess of the Facility's Net Output during that same hour.

"Surplus Delivery" means any energy delivered by the Facility in excess of hourly Net Output that is not offset by the delivery of energy in deficit of hourly Net Output during the Settlement Period. PacifiCorp shall accept Surplus Delivery, but shall not pay for it.

Interconnection Agreement Samples

ADDENDUM W-ctd.

SELLER'S OBLIGATIONS IN LIEU OF THOSE CONTAINED IN A GENERATION INTERCONNECTION AGREEMENT.

1. **Seller's Responsibility to Arrange for Delivery of Net Output to Point of Delivery.** Seller shall arrange for the Firm Delivery of Net Output to the Point of Delivery. Seller shall comply with the terms and conditions of the Transmission Agreement(s) between the Seller and the Transmitting Entity(s). Whenever Seller fails to provide for Firm Delivery of Net Output, all Net Output delivered via non-firm transmission rights shall be deemed Excess Output, and therefore subject to the payment provision in Section 5.4.

2. **Seller's Responsibility to Schedule Delivery.** Seller shall coordinate with the Transmitting Entity(s) to provide PacifiCorp with a schedule of the next Day's hourly scheduled Net Output deliveries at least 24 (twenty-four) hours prior to the beginning of the day being scheduled, and otherwise in accordance with the WECC Prescheduling Calendar (which is updated annually and may be downloaded at: <http://www.wecc.biz/>).

3. **Seller's Responsibility to Maintain Interconnection Facilities.** PacifiCorp shall have no obligation to install or maintain any interconnection facilities on Seller's side of the Point of Interconnection. PacifiCorp shall not pay any costs arising from Seller interconnecting its Facility with the Transmitting Entity(s).

4. **Seller's Responsibility to Pay Transmission Costs.** Seller shall make all arrangements for, and pay all costs associated with, transmitting Net Output to PacifiCorp, scheduling energy into the PacifiCorp system and any other costs associated with delivering the Seller's Net Output to the Point of Delivery.

5. **Energy Reserve Requirements.** The Transmitting Entity shall provide all generation reserves as required by the WECC and/or as required by any other governing agency or industry standard to deliver the Net Energy to the Point of Delivery, at no cost to PacifiCorp.

6. **Seller's Responsibility to Report Net Output.** On or before the tenth (10th) day following the end of each Billing Period, Seller shall send a report documenting hourly station service, Excess Output, and Net Output from the Facility during the previous Billing Period, in columnar format substantially similar to the attached **Example 1**. If requested, Seller shall provide an electronic copy of the data used to calculate Net Output, in a standard format specified by PacifiCorp. For each day Seller is late delivering the certified report, PacifiCorp shall be entitled to postpone its payment deadline in Section 9 of this Power Purchase Agreement by one day. Seller hereby grants PacifiCorp the right to audit its certified reports of hourly Net Output. In the event of discovery of a billing error resulting in underpayment or overpayment, the Parties agree to limit recovery to a period of three years from the date of discovery.

7. **Seller's Supplemental Representations and Warranties.** In addition to the Seller's representations and warranties contained in Section 3 of this Agreement, Seller warrants that:

- (a) Seller's Supplemented Output, if any, results from Seller's purchase of some form of energy imbalance ancillary service;

Interconnection Agreement Samples

ADDENDUM W-ctd.

(b) The Transmitting Entity(s) requires Seller to procure the service, above, as a condition of providing transmission service;

(c) The Transmitting Entity requires Seller to schedule deliveries of Net Output in increments of no less than one (1) megawatt;

(d) Seller is not attempting to sell PacifiCorp energy or capacity in excess of its Net Output; and

(e) The energy imbalance service, above, is designed to correct a mismatch between energy scheduled by the QF and the actual real-time production by the QF.

8. **Seller's Right to Deliver Supplemented Output.** In reliance upon Seller's warranties in Section 5, above, PacifiCorp agrees to accept and pay for Supplemented Output; *provided, however, that* Seller agrees to achieve an EIA of zero (0) kilowatt-hours during On-Peak Hours and zero (0) kilowatt-hours during Off-Peak Hours at the end of each Settlement Period.

(a) **Remedy for Seller's Failure to Achieve zero EIA.** In the event Seller does not achieve zero EIA at the end of each Settlement Period, PacifiCorp will declare any positive balance to be Surplus Delivery, and Seller's EIA will be reset to zero. PacifiCorp will include an accounting of Surplus Delivery in each monthly statement provided to Seller pursuant to Section 9.1 of this Agreement.

(b) **Negative Energy Imbalance Accumulations.** Any negative EIA (indicating that the Transmitting Entity has delivered less than Seller's Net Output), will be reset to zero at the end of each Settlement Period without any corresponding compensation by PacifiCorp.

(c) **PacifiCorp's Option to Change EIA Settlement Period.** In the event PacifiCorp reasonably determines that doing so likely will have a *de minimis* net effect upon the cost of Seller's Net Output to PacifiCorp, it may elect to enlarge the Settlement Period, up to a maximum of one Contract Year. Conversely, if PacifiCorp reasonably determines, based on the QF's performance during the current year, that reducing the Settlement Period likely will significantly lower the net cost of Seller's Net Output to PacifiCorp, it shall have the right to shorten Seller's EIA settlement period beginning the first day of the following Contract Year. However, in no case shall the Settlement Period be less than one month.

Interconnection Agreement Samples

ADDENDUM W—Example 1

Example of Seller's Output Reporting Requirement

		A	B	C (=A-B)	D	E (=Max (0, C-D))	
	Hour ending (HE)	Meter Reading ^v at Point of Interconnectio n (MWh)	Meter reading at Station Power Meter* (MWh)	Net Output (MWh)	Facility Capacity Rating (MW)	Excess Output (MWh)	
Day	1	7:00	0.50	0.01	0.49	1.50	
	1	8:00	0.50	0.02	0.48	1.50	
	1	9:00	0.50	0.01	0.49	1.50	
	1	10:00	0.50	0.01	0.49	1.50	
	1	11:00	0.50	0.01	0.49	1.50	
	1	12:00	1.60	0.01	1.59	1.50	0.09
	1	13:00	1.70	0.01	1.69	1.50	0.19
	1	14:00	1.60	0.01	1.59	1.50	0.09
	1	15:00	1.50	0.01	1.49	1.50	
	1	16:00	1.50	0.01	1.50	1.50	
	1	17:00	1.50	0.00	1.50	1.50	
	1	18:00	1.50	0.01	1.49	1.50	
	1	19:00	0.50	0.02	0.48	1.50	
	1	20:00	0.50	0.01	0.49	1.50	

^v Seller shall show adjustment of Meter Reading for losses, if any, between point of metering and the Point of Interconnection, in accordance with Section 8.1.

* Does not apply if Station Service is provided from the gross output of the Facility.



**Small Generator Facility
Interconnection Equipment As-Built Specifications, Initial Settings, and Operating
Requirements***

Facility Location and Contact Information

Applicant: _____

Facility Operator (if different than previous): _____

Facility Contact Phone: _____ Cell phone: _____

Location Address/ GPS Coordinates: _____

City: _____ State: _____ Zip Code: _____

Application Completion Date: _____

Revision Date (if applicable): _____

Energy Production Equipment/Inverter Information

Synchronous Induction Inverter Other _____

Electric Nameplate Rating: _____ kW _____ kVA

Rated Voltage: _____ Volts

Rated Current: _____ Amps

Phase: Single 3-Phase

System Type Tested (Total System): Yes No (attach product literature)

Other Facility Information

Electrical One-Line Diagram (showing complete circuit between generator and proposed point-of-interconnection, including all protective devices, etc.)

Site Plan (including all protective devices, including isolation device location, point(s) of common coupling, and generator location)

Isolation Device Type: _____

Grounding Configuration: _____

Initial Commissioning Date: _____

* Initial operating set points and 'as-built' equipment data is to be recorded on or about the time of the Witness Test. It shall remain part of the permanent interconnection record described in OAR 860-082-0065. **Parties may not deviate from initial settings and agreed upon operating parameters except as permitted by the Rule, without written authorization of PGE.** The Interconnection Customer will furnish updated information to PGE any time a special operating requirement initial set point or the Interconnection Equipment is materially changed.

Switchgear/Circuit Interruption Devices

Switchgear type and control: (used to bring generator on line)

Circuit Breakers: Closed-transition Open-transition Auto Transfer Switch

Nameplate: _____

Telemetry

Telemetry Requirements: _____

System Configuration: _____

Data Scan Rate: _____

Data Point List: _____

Telemetry Data Delivery Location: _____

Initial Set Points at Point of Interconnection

Voltage: _____ kVAR: _____

Power factor: _____

Other: _____

Other: _____

Trip Re-Start Protocol

Reclosing Practice: _____

Hold out time: _____

Ramp Rate: _____

Notification required: Yes No

Operations and Maintenance Schedule

Operating Hours: _____ Availability: _____%

Seasonal Effect: _____

Routine and Annual Maintenance Schedule: _____

Applicant Signature:

I hereby certify that all of the information provided in this document is correct.

Applicant Signature: _____ Date: _____

Printed Name: _____ Title (*if applicable*): _____

**SCHEDULE 201
QUALIFYING FACILITY 10 MW or LESS
AVOIDED COST POWER PURCHASE INFORMATION**

PURPOSE

To provide information about Avoided Costs, Standard Contracts and negotiated Power Purchase Agreements, power purchase prices and price options for power delivered by a Qualifying Facility (QF) to the Company with nameplate capacity of 10,000 kW (10MW) or less.

(T)

AVAILABLE

To owners of QFs making sales of electricity to the Company in the State of Oregon (Seller).

APPLICABLE

For power purchased from small power production or cogeneration facilities that are QFs as defined in 18 Code of Federal Regulations (CFR) Section 292, that meet the eligibility requirements described herein and where the energy is delivered to the Company's system and made available for Company purchase pursuant to a Standard Contract Power Purchase Agreement.

ESTABLISHING CREDITWORTHINESS

The Seller must establish creditworthiness prior to service under this schedule. For a Standard Contract Power Purchase Agreement (Standard Contract), a Seller may establish creditworthiness with a written acknowledgment that it is current on all existing debt obligations and that it was not a debtor in a bankruptcy proceeding within the preceding 24 months. If the Seller is not able to establish creditworthiness, the Seller must provide security as deemed sufficient by the Company as set out in the Standard Contract.

POWER PURCHASE INFORMATION

A Seller may call the Power Production Coordinator at (503) 464-8000 to obtain more information about being a Seller or how to apply for service under this schedule.

SCHEDULE 201 (Continued)

POWER PURCHASE AGREEMENT

In accordance with terms set out in this schedule and the Commission's Rules as applicable, the Company will purchase any Energy in excess of station service (power necessary to produce generation) and amounts attributable to conversion losses, which are made available from the Seller.

A Seller must execute a Power Purchase Agreement with the Company prior to delivery of power to the Company. The agreement will have a term of up to 20 years as selected by the QF.

A QF with a nameplate capacity rating of 10 MW or less as defined herein may elect the option of a Standard Contract.

Any Seller may elect to negotiate a Power Purchase Agreement with the Company. Such negotiation will comply with the requirements of the Federal Energy Regulatory Commission (FERC), and the Commission including the guidelines in Order No. 07-360, and Schedule 202. Negotiations for power purchase pricing will be based on the filed Avoided Costs in effect at that time.

STANDARD CONTRACTS (Nameplate capacity of 10 MW or less)

A Seller choosing a Standard Contract will complete all informational and price option selection requirements in the applicable Standard Contract (Appendix 1 to this schedule) and submit the executed Agreement to the Company prior to service under this schedule. The Standard Contract is available at www.portlandgeneral.com. The available Standard Contracts are: Standard Contract Power Purchase Agreement, Standard Contract Off System Power Purchase Agreement, Standard Contract for Intermittent Resources and Standard Contract for Off System Intermittent Resources. The Standard Contracts applicable to Intermittent Resources are available only to QFs utilizing wind, solar or run of river hydro as the primary motive force.

GUIDELINES FOR 10 MW OR LESS FACILITIES

(T)

In order to execute the Standard Contract the Seller must complete all of the general project information requested in the applicable Standard Contract.

When all information required in the Standard Contract has been received in writing from the Seller, the Company will respond within 15 business days with a draft Standard Contract.

The Seller may request in writing that the Company prepare a final draft Standard Contract. The Company will respond to this request within 15 business days. In connection with such request the QF must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft Standard Contract.

When both parties are in full agreement as to all terms and conditions of the draft Standard Contract, the Company will prepare and forward to the Seller a final executable version of the agreement within 15 business days. Following the Company's execution, a completely executed copy will be returned to the Seller. Prices and other terms and conditions in the power purchase agreement will not be final and binding until the Standard Contract has been executed by both parties.

SCHEDULE 201 (Continued)

OFF SYSTEM POWER PURCHASE AGREEMENT

A Seller with a facility that interconnects with an electric system other than the Company's electric system may enter into a power purchase agreement with the Company after following the applicable standard or negotiated contract guidelines and making the arrangements necessary for transmission of power to the Company's system.

BASIS FOR POWER PURCHASE PRICE

AVOIDED COST SUMMARY

The power purchase rates are based on the Company's Avoided Costs. Avoided Costs are defined in 18 CFR 292.101(6) 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."

The Avoided Costs as listed in Tables 1 and 2 below include monthly On- and Off-Peak prices.

ON-PEAK PERIOD

The On-Peak period is 6:00 a.m. until 10:00 p.m., Monday through Saturday.

OFF-PEAK PERIOD

The Off-Peak period is 10:00 p.m. until 6:00 a.m., Monday through Saturday, and all day on Sunday.

Avoided Costs are based on forward market price estimates through December 2012, the period of time during which the Company's Avoided Costs are associated with incremental purchases of Energy and capacity from the market. For the period 2013 through 2028, the Avoided Costs reflect the fully allocated costs of a natural gas fueled combined cycle combustion turbine (CCCT) including fuel and capital costs. The CCCT Avoided Costs are based on the variable cost of Energy plus capitalized Energy costs at a 93% capacity factor based on a natural gas price forecast, with prices modified for shrinkage and transportation costs. (C)

PRICING OPTIONS FOR STANDARD CONTRACTS

Pricing options represent the purchase price per MWh the Company will pay for electricity delivered to a Point of Delivery (POD) within the Company's service territory pursuant to a Standard Contract up to the nameplate rating of the QF in any hour. Any Energy delivered in excess of the nameplate rating will be purchased at the applicable Off-Peak Prices for the selected pricing option. (C)

The Standard Contract pricing will be based on the Avoided Cost in effect at the time the agreement is executed.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)

Four pricing options are available for Standard Contracts. The pricing options include one Fixed Rate Option and three Market Based Options.

1) Fixed Price Option

The Fixed Price Option is based on Avoided Costs including forecasted natural gas prices.

This option is available for a maximum term of 15 years. Sellers with contracts exceeding 15 years will make a one time election at execution to select a Market-Based Option for all years up to five in excess of the initial 15. Under the Fixed Price Option, prices will be as established at the time the Standard Contract is executed and will be equal to the Avoided Costs in Tables 1 and 2 effective at execution for a term of up to 15 years.

TABLE 1												
Avoided Costs												
Fixed Price Option												
On-Peak Forecast (\$/MWH)												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	N/A	N/A	N/A	N/A	N/A	N/A	N/A	32.71	31.59	32.46	41.21	50.34
2010	51.25	47.75	42.75	41.00	36.00	33.25	53.75	58.25	57.75	53.75	56.00	59.25
2011	60.30	56.80	53.55	47.55	40.80	39.55	64.05	66.80	63.55	58.80	62.05	65.05
2012	62.07	57.81	51.71	49.58	43.48	40.13	65.12	70.61	70.00	65.12	67.86	71.83
2013	97.44	97.41	95.83	90.96	90.67	91.16	91.72	92.21	92.38	92.90	94.45	96.26
2014	96.31	96.28	94.76	90.04	89.79	90.26	90.83	91.27	91.46	91.99	93.47	95.24
2015	94.54	94.51	93.07	88.60	88.36	88.81	89.35	89.76	89.94	90.45	91.85	93.52
2016	94.77	94.74	93.32	88.90	88.66	89.11	89.64	90.05	90.23	90.73	92.12	93.77
2017	97.00	96.97	95.52	90.99	90.75	91.21	91.75	92.17	92.35	92.86	94.28	95.97
2018	100.22	100.19	98.67	93.92	93.66	94.14	94.71	95.15	95.34	95.88	97.37	99.15
2019	104.73	104.70	103.07	97.98	97.71	98.22	98.83	99.30	99.51	100.08	101.68	103.58
2020	105.39	105.35	103.73	98.65	98.38	98.89	99.50	99.97	100.17	100.75	102.34	104.23
2021	107.84	107.81	106.14	100.94	100.67	101.19	101.81	102.29	102.50	103.09	104.72	106.66
2022	110.17	110.13	108.43	103.10	102.82	103.35	103.99	104.49	104.70	105.30	106.97	108.96
2023	113.96	113.92	112.13	106.56	106.26	106.82	107.49	108.01	108.23	108.86	110.61	112.69
2024	117.35	117.31	115.45	109.62	109.31	109.89	110.59	111.13	111.37	112.03	113.85	116.03
2025	119.74	119.70	117.80	111.86	111.55	112.14	112.85	113.41	113.65	114.32	116.18	118.40
2026	122.01	121.97	120.04	113.99	113.66	114.27	115.00	115.56	115.80	116.49	118.38	120.64
2027	124.33	124.29	122.32	116.15	115.82	116.44	117.18	117.75	118.00	118.70	120.63	122.93
2028	126.65	126.61	124.60	118.32	117.98	118.61	119.37	119.95	120.20	120.91	122.88	125.23

(C)

 (C)

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
 FIXED PRICE OPTION (Continued)

TABLE 2												
Avoided Costs												
Fixed Price Option												
Off-Peak Forecast (\$/MWH)												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	N/A	N/A	N/A	N/A	N/A	N/A	N/A	26.59	27.21	27.71	35.21	43.71
2010	44.75	42.75	37.75	34.75	26.25	23.75	40.25	44.00	41.75	42.75	48.75	55.25
2011	55.30	51.80	48.05	36.80	29.80	27.30	45.30	50.55	50.30	49.80	53.80	57.05
2012	53.00	50.62	44.66	41.08	30.95	27.97	47.64	52.11	49.42	50.62	57.77	65.52
2013	64.67	64.64	63.06	58.19	57.89	58.39	58.94	59.44	59.60	60.13	61.68	63.49
2014	62.91	62.88	61.37	56.64	56.39	56.86	57.43	57.87	58.06	58.60	60.08	61.84
2015	60.51	60.48	59.04	54.57	54.33	54.78	55.32	55.73	55.91	56.42	57.82	59.49
2016	60.20	60.17	58.76	54.33	54.10	54.54	55.07	55.48	55.66	56.16	57.55	59.20
2017	61.55	61.52	60.07	55.55	55.30	55.76	56.30	56.72	56.90	57.42	58.83	60.52
2018	64.22	64.19	62.66	57.91	57.66	58.13	58.70	59.15	59.34	59.88	61.37	63.14
2019	68.04	68.01	66.38	61.29	61.02	61.53	62.14	62.61	62.82	63.39	64.99	66.89
2020	68.12	68.08	66.46	61.38	61.11	61.62	62.23	62.70	62.91	63.48	65.07	66.97
2021	69.74	69.71	68.04	62.84	62.57	63.09	63.71	64.20	64.40	64.99	66.62	68.56
2022	71.34	71.31	69.60	64.28	63.99	64.53	65.17	65.66	65.88	66.48	68.15	70.14
2023	74.27	74.23	72.45	66.87	66.57	67.13	67.80	68.32	68.54	69.18	70.92	73.01
2024	77.17	77.13	75.26	69.44	69.12	69.71	70.41	70.95	71.18	71.84	73.67	75.84
2025	78.66	78.62	76.72	70.79	70.47	71.06	71.78	72.33	72.57	73.24	75.10	77.32
2026	80.16	80.12	78.18	72.13	71.81	72.41	73.14	73.70	73.94	74.63	76.53	78.78
2027	81.68	81.64	79.66	73.50	73.17	73.78	74.52	75.10	75.35	76.04	77.98	80.28
2028	83.19	83.15	81.14	74.85	74.52	75.15	75.90	76.49	76.74	77.45	79.42	81.77

(C)

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Under the Fixed Price Option, the Company will pay Seller the Off-Peak Avoided Cost pursuant to Table 2 for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any Contract Year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard Contract; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. The Company will pay the Seller the On-Peak Avoided Cost pursuant to Table for all other output. (See Appendix 1, the Standard Contract for defined terms.)

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SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)

MARKET BASED PRICE OPTIONS:

Market Based Price Options include Option 2, Deadband Index Gas Price; Option 3, Index Gas Price; and Option 4, Dow Jones Mid-Columbia Daily On- and Off-Peak Electricity Firm Price Index (DJ-Mid-C Firm Index). The price components for pricing Options 2 and 3 are defined as follows:

On Peak Price:	P_{Peak}	
Off Peak Price:	P_{Off}	
Variable Operating and Maintenance, Fixed Costs, and Gas Transportation (Table 6):	VFG	
Capacity Value (Table 7):	C	
Heat Rate:	HR = 6,732 BTU/kWh	(C)
Losses: 1.9%		
Forecasted Gas Price (Table 5):	GP_F	
First of Month* Northwest Pipeline Corp. Canadian Border Index as Reported in <u>Platts</u> <u>Inside FERC's Gas Market Report</u> GP	Sumas	
First of Month* one-month spot price averages for AECO/NIT transactions as Reported in <u>Canadian Gas Price Reporter</u> <u>Natural Gas Market Report</u> (in US dollars):	GP_{AECO}	
Monthly Indexed Gas Price:	$GP_{MI} = (GP_{Sumas} + GP_{AECO})/2$	
Deadband Gas Index:	GP_{DB}	

Where:

If $GP_{MI} > GP_F$
 $GP_{DB} = \text{Minimum of } (GP_{MI} \text{ or } 1.1 * GP_F)$
Otherwise
 $GP_{DB} = \text{Maximum of } (GP_{MI} \text{ or } .9 * GP_F)$

* "First of Month" means the first such monthly issuance.

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
 MARKET BASED PRICE OPTIONS (Continued)

Tables 3 and 4 below list applicable rates for Options 2(Deadband Index Gas Price Option) and 3 (Index Gas Price Option) for the period through 2012. The monthly On- and Off-Peak prices will be applied for all Market Based Price Options.

TABLE 3												
Avoided Costs												
On-Peak Resource Sufficiency Rate (\$/MWH)												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	N/A	N/A	N/A	N/A	N/A	N/A	N/A	32.71	31.59	32.46	41.21	50.34
2010	51.25	47.75	42.75	41.00	36.00	33.25	53.75	58.25	57.75	53.75	56.00	59.25
2011	60.30	56.80	53.55	47.55	40.80	39.55	64.05	66.80	63.55	58.80	62.05	65.05
2012	62.07	57.81	51.71	49.58	43.48	40.13	65.12	70.61	70.00	65.12	67.86	71.83

TABLE 4												
Avoided Costs												
Off-Peak Resource Sufficiency Rate (\$/MWH)												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	N/A	N/A	N/A	N/A	N/A	N/A	N/A	26.59	27.21	27.71	35.21	43.71
2010	44.75	42.75	37.75	34.75	26.25	23.75	40.25	44.00	41.75	42.75	48.75	55.25
2011	55.30	51.80	48.05	36.80	29.80	27.30	45.30	50.55	50.30	49.80	53.80	57.05
2012	53.00	50.62	44.66	41.08	30.95	27.97	47.64	52.11	49.42	50.62	57.77	65.52

SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

(M)

2) Deadband Index Gas Price Option

The Deadband Index Gas Price Option bases the fuel price component of the Energy rate on comparisons between the Forecast Gas Price (Table 5) and the simple average of the First of Month gas indices for Sumas and AECO trading hubs. The Northwest Pipeline Gas Index (Sumas) will be as reported in Platts Inside FERC's Gas Market Report. The AECO/NIT (AECO) Gas Index will be as reported in Canadian Gas Price Reporter Natural Gas Market Report (in US dollars). The fuel price component used will be bound between 90% and 110% of the natural gas price forecast but based on the then current gas price.

The price paid per MWh will be:

$$\begin{aligned} P_{\text{Peak}} &= GP_{\text{DB}} * HR / 1,000 / (1 - \text{Losses}) + VFG + C \\ P_{\text{Off}} &= GP_{\text{DB}} * HR / 1,000 / (1 - \text{Losses}) + VFG \end{aligned}$$

Under the Deadband method, the Company will pay Seller the Off-Peak prices for: (a) all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any Contract Year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard Contract; (d) Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. All other purchases will be at On-Peak prices. (See Appendix 1, the Standard Contract for defined terms.)

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SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
MARKET BASED PRICE OPTIONS (Continued)

3) Index Gas Price Option

The Index Gas Price Option is the simple average of the First of Month gas indices for Sumas and AECO trading hubs used in establishing the Avoided Costs. The Sumas Gas Index will be as reported in Platts Inside FERC's Gas Market Report. The AECO Gas Index will be as reported in the Canadian Gas Price Reporter Natural Gas Market Report (in US dollars).

The price paid per MWh will be:

$$\begin{aligned} P_{\text{Peak}} &= GP_{\text{MI}} * \text{HR} / 1,000 / (1 - \text{Losses}) + \text{VFG} + \text{C} \\ P_{\text{Off}} &= GP_{\text{MI}} * \text{HR} / 1,000 / (1 - \text{Losses}) + \text{VFG} \end{aligned}$$

Under the Index Gas Price, the Company will pay Seller the Off-Peak Prices for: (a) for all Net Output delivered prior to the Commercial Operation Date; (b) all Net Output deliveries greater than Maximum Net Output in any Contract Year; (c) any generation subject to and as adjusted by the provisions of Section 4.3 of the Standard Contract; (d) for Net Output delivered in the Off-Peak Period; and (e) deliveries above the nameplate capacity in any hour. All other purchases will be at On-Peak prices. (See Appendix 1, the Standard Contract for defined terms.)

4) Mid C Index Price Option

Under this option, prices paid per MWh will be based on the DJ-Mid-C Firm Index plus 0.221 ¢ per kWh for wholesale wheeling.

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SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
 MARKET BASED PRICE OPTIONS (Continued)

Table 5 contains the gas pricing components for Option 1 (Fixed Price Option) and Option 2 (Deadband Index Gas Price Option).

TABLE 5												
Forecasted Gas Price - GP _F (\$/MMBTU) - Without Transportation												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2013	7.41	7.41	7.18	6.48	6.44	6.51	6.59	6.66	6.69	6.76	6.98	7.24
2014	7.13	7.12	6.90	6.23	6.19	6.26	6.34	6.40	6.43	6.51	6.72	6.97
2015	6.75	6.74	6.54	5.89	5.86	5.92	6.00	6.06	6.09	6.16	6.36	6.60
2016	6.67	6.67	6.46	5.83	5.79	5.86	5.93	5.99	6.02	6.09	6.29	6.53
2017	6.82	6.82	6.61	5.96	5.93	5.99	6.07	6.13	6.16	6.23	6.43	6.67
2018	7.17	7.16	6.94	6.26	6.23	6.29	6.38	6.44	6.47	6.54	6.76	7.01
2019	7.68	7.67	7.44	6.71	6.67	6.74	6.83	6.90	6.93	7.01	7.24	7.51
2020	7.65	7.65	7.41	6.69	6.65	6.72	6.81	6.88	6.91	6.99	7.22	7.49
2021	7.84	7.84	7.60	6.85	6.81	6.89	6.98	7.05	7.08	7.16	7.39	7.67
2022	8.03	8.02	7.78	7.02	6.98	7.05	7.14	7.22	7.25	7.33	7.57	7.86
2023	8.41	8.40	8.15	7.35	7.30	7.38	7.48	7.56	7.59	7.68	7.93	8.23
2024	8.79	8.78	8.51	7.68	7.63	7.72	7.82	7.89	7.93	8.02	8.28	8.60
2025	8.95	8.95	8.67	7.82	7.78	7.86	7.97	8.04	8.08	8.18	8.44	8.76
2026	9.12	9.12	8.84	7.97	7.93	8.01	8.12	8.20	8.23	8.33	8.60	8.93
2027	9.30	9.29	9.01	8.12	8.08	8.16	8.27	8.35	8.39	8.49	8.77	9.10
2028	9.47	9.47	9.18	8.28	8.23	8.32	8.43	8.51	8.55	8.65	8.93	9.27

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SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
 MARKET BASED PRICE OPTIONS (Continued)

Table 6 contains the Variable O&M and Fixed Costs that are derived from a natural gas-fired CCCT. (C)

TABLE 6												
Variable O&M, Fixed Costs and Gas Transportation Forecast - VFG (\$/MWH)												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2013	13.95	13.95	13.92	13.81	13.80	13.82	13.83	13.84	13.84	13.85	13.89	13.93
2014	14.15	14.15	14.12	14.02	14.01	14.02	14.03	14.04	14.05	14.06	14.09	14.13
2015	14.34	14.34	14.31	14.21	14.21	14.22	14.23	14.24	14.24	14.25	14.28	14.32
2016	14.56	14.56	14.52	14.43	14.42	14.43	14.44	14.45	14.46	14.47	14.50	14.53
2017	14.87	14.86	14.83	14.74	14.73	14.74	14.75	14.76	14.76	14.78	14.81	14.84
2018	15.18	15.18	15.15	15.04	15.04	15.05	15.06	15.07	15.07	15.09	15.12	15.16
2019	15.53	15.53	15.49	15.38	15.37	15.38	15.40	15.41	15.41	15.42	15.46	15.50
2020	15.76	15.76	15.73	15.62	15.61	15.62	15.64	15.65	15.65	15.66	15.70	15.74
2021	16.10	16.10	16.06	15.95	15.95	15.96	15.97	15.98	15.99	16.00	16.03	16.08
2022	16.41	16.41	16.38	16.26	16.25	16.27	16.28	16.29	16.29	16.31	16.34	16.39
2023	16.76	16.76	16.72	16.60	16.59	16.60	16.62	16.63	16.64	16.65	16.69	16.73
2024	17.08	17.08	17.04	16.91	16.90	16.92	16.93	16.94	16.95	16.96	17.00	17.05
2025	17.44	17.44	17.39	17.27	17.26	17.27	17.29	17.30	17.30	17.32	17.36	17.41
2026	17.77	17.77	17.72	17.59	17.59	17.60	17.62	17.63	17.63	17.65	17.69	17.74
2027	18.11	18.10	18.06	17.93	17.92	17.93	17.95	17.96	17.97	17.98	18.02	18.07
2028	18.41	18.41	18.37	18.23	18.22	18.24	18.25	18.27	18.27	18.29	18.33	18.38

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SCHEDULE 201 (Continued)

PRICING OPTIONS FOR STANDARD CONTRACTS (Continued)
 MARKET BASED PRICE OPTIONS (Continued)

Table 7 represents the variable C in the formulas for Option 2 (Deadband Index Gas PriceOption) and Option 3 (Index Gas Price Option).

TABLE 7												
Capacity Value - C (\$/MWH)												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2013	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77	32.77
2014	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40	33.40
2015	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03	34.03
2016	34.57	34.57	34.57	34.57	34.57	34.57	34.57	34.57	34.57	34.57	34.57	34.57
2017	35.45	35.45	35.45	35.45	35.45	35.45	35.45	35.45	35.45	35.45	35.45	35.45
2018	36.01	36.01	36.01	36.01	36.01	36.01	36.01	36.01	36.01	36.01	36.01	36.01
2019	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69	36.69
2020	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27	37.27
2021	38.10	38.10	38.10	38.10	38.10	38.10	38.10	38.10	38.10	38.10	38.10	38.10
2022	38.82	38.82	38.82	38.82	38.82	38.82	38.82	38.82	38.82	38.82	38.82	38.82
2023	39.69	39.69	39.69	39.69	39.69	39.69	39.69	39.69	39.69	39.69	39.69	39.69
2024	40.18	40.18	40.18	40.18	40.18	40.18	40.18	40.18	40.18	40.18	40.18	40.18
2025	41.08	41.08	41.08	41.08	41.08	41.08	41.08	41.08	41.08	41.08	41.08	41.08
2026	41.86	41.86	41.86	41.86	41.86	41.86	41.86	41.86	41.86	41.86	41.86	41.86
2027	42.65	42.65	42.65	42.65	42.65	42.65	42.65	42.65	42.65	42.65	42.65	42.65
2028	43.46	43.46	43.46	43.46	43.46	43.46	43.46	43.46	43.46	43.46	43.46	43.46

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SCHEDULE 201 (Continued)

MONTHLY SERVICE CHARGE

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Each separately metered QF not associated with a retail Customer account will be charged \$10.00 per month.

INSURANCE REQUIREMENTS

The following insurance requirements are applicable to Sellers with a Standard Contract:

- 1) QFs with nameplate capacity ratings greater than 200 kW are required to secure and maintain a prudent amount of general liability insurance. The Seller must certify to the Company that it is maintaining general liability insurance coverage for each QF at prudent amounts. A prudent amount will be deemed to mean liability insurance coverage for both bodily injury and property damage liability in the amount of not less than \$1,000,000 each occurrence combined single limit, which limits may be required to be increased or decreased by the Company as the Company determines in its reasonable judgment economic conditions or claims experience may warrant.
- 2) Such insurance will include an endorsement naming the Company as an additional insured insofar as liability arising out of operations under this schedule and a provision that such liability policies will not be canceled or their limits reduced without 30 days' written notice to the Company. The Seller will furnish the Company with certificates of insurance together with the endorsements required herein. The Company will have the right to inspect the original policies of such insurance.
- 3) QFs with a design capacity of 200 kW or less are encouraged to pursue liability insurance on his/her own. The Oregon Public Utility Commission in Order No. 05-584 determined that it is inappropriate to require QFs that have a design capacity of 200 kW or less to obtain general liability insurance.

TRANSMISSION AGREEMENTS

If the QF is located outside the Company's service territory, the Seller is responsible for the transmission of power at its cost to the Company's service territory.

INTERCONNECTION REQUIREMENTS

Except as otherwise provided in a generation Interconnection Agreement between the Company and Seller, if the QF is located within the Company's service territory, switching equipment capable of isolating the QF from the Company's system will be accessible to the Company at all times. At the Company's option, the Company may operate the switching equipment described above if, in the sole opinion of the Company, continued operation of the QF in connection with the utility's system may create or contribute to a system emergency.

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SCHEDULE 201 (Continued)

INTERCONNECTION REQUIREMENTS (Continued)

The QF owner interconnecting with the Company's distribution system must comply with all requirements for interconnection as established pursuant to Commission rule, in the Company's Rules and Regulations (Rule C) or the Company's Interconnection Procedures contained in its FERC Open Access Transmission Tariff (OATT), as applicable. The Seller will bear full responsibility for the installation and safe operation of the interconnection facilities.

DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER PRODUCTION FACILITY ELIGIBLE TO RECEIVE THE STANDARD RATES AND STANDARD CONTRACT

A QF will be eligible to receive the standard rates and Standard Contract if the nameplate capacity of the QF, together with any other electric generating facility using the same motive force, owned or controlled by the same person(s) or affiliated person(s), and located at the same site, does not exceed 10 MW.

Definition of Person(s) or Affiliated Person(s)

As used above, the term "same person(s)" or "affiliated person(s)" means a natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. However, two facilities will not be held to be owned or controlled by the same person(s) or affiliated person(s) solely because they are developed by a single entity.

Furthermore, two facilities will not be held to be owned or controlled by the same person(s) or affiliated person(s) if such common person or persons is a "passive investor" whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit. A unit of Oregon local government may also be a "passive investor" if the local governmental unit demonstrates that it will not have an equity ownership interest nor exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Definition of Same Site

For purposes of the foregoing, generating facilities are considered to be located at the same site as the QF for which qualification for the standard rates and Standard Contract is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for the standard rates and standard contract is sought.

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(C)

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SCHEDULE 201 (Concluded)

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DEFINITION OF A SMALL COGENERATION FACILITY OR SMALL POWER
PRODUCTION FACILITY ELIGIBLE TO RECEIVE THE STANDARD RATES
AND STANDARD CONTRACT (Continued)

(M)

Shared Interconnection and Infrastructure

QFs otherwise meeting the above-described separate ownership test and thereby qualified for entitlement to the standard rates and Standard Contract will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for the standard rates and Standard Contract so long as the use of the shared interconnection complies with the interconnecting utility's safety and reliability standards, interconnection contract requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility's approved Standard Contract.

Dispute Resolution

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to the standard rates and Standard Contract. Any dispute concerning a QF's entitlement to the standard rates and Standard Contract will be presented to the Commission for resolution. (T)

SPECIAL CONDITIONS

1. Delivery of energy by Seller will be at a voltage, phase, frequency, and power factor as specified by the Company.
2. If the Seller also receives retail Electricity Service from the Company at the same location, any payments under this schedule will be credited to the Seller's retail Electricity Service bill. At the option of the Customer, any net credit over \$10.00 will be paid by check to the Customer.
3. Contracts entered into pursuant to this schedule will not terminate prior to the Standard or negotiated contract's termination date if the 1978 Public Utility Regulatory Policies Act (PURPA) is repealed.

TERM OF AGREEMENT

Not less than one year and not to exceed 20 years.

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Interconnection Agreement Samples

Attachment: 2.0 MW Net Electric Production

Assumptions:

2 Megawatt (MW) bio-gas powered compression engine generator (Caterpillar G3520C, GE Jenbacher Type 6, Cummins 2000 DQKAB) or equivalent)
 Mean thermal efficiency estimated at 35% thermal efficiency; rounded up to 10,000 British Thermal Units (BTU's) per kilowatt hour (kWh)
 360 hours of shut down per year (15 days averaged over all months)
 Production at 2 MW capacity begins 2012
 Green waste mean gas capacity of .29 cubic meters of CH4 per kilogram or 16.05 cubic feet of CH4 per pound; rounded down to 2 million Btu/ton based on Willamette Valley feedstock laboratory trials.
 Engine generator gas requirements are 20,060 cubic feet of CH4 (20.06 million Btu/hr) per hour at 1,000 Btu's per cubic foot
 Feedstock revenue is based on \$30 per ton tipping fee for 50,000 tons and purchase of the remaining 37,000 tons at \$30
 Engine waste heat assumes 20% recoverable with thermal load coincidence variability and exchanger efficiency for jacket cooling water (40%) and exhaust (60%, in Btu's per month)

Production Month	Days	Hours	Run Hours	MW	MWH	Ancillary Loads in kW kWh				Net MWH	Gas Cubic Fee	Feed Stock Tons	Recoverable		Therm	Feedstock
						Pumps	Cooling Tox	Sum Loads	Ave KW				Engine Waste	Waste Heat		
Jan	31	744	709.03	2.000	1,418.06	2.0	12.0	1,430	2.02	1,417	14,676,962	7,338	1,176,993,120	11,770	\$ 8,239	\$ 30,822
Feb	28	672	641.09	2.000	1,282.18	2.0	12.0	1,294	2.02	1,281	13,270,522	6,635	1,064,206,080	10,642	\$ 7,449	\$ 27,868
Mar	31	744	714.24	2.000	1,428.48	2.0	12.0	1,440	2.02	1,427	14,784,768	7,392	1,185,638,400	11,856	\$ 8,299	\$ 31,048
Apr	30	720	691.20	2.000	1,382.40	2.0	12.0	1,394	2.02	1,381	14,307,840	7,154	1,147,392,000	11,474	\$ 8,032	\$ 30,046
May	31	744	714.24	2.000	1,428.48	2.0	12.0	1,440	2.02	1,427	14,784,768	7,392	1,185,638,400	11,856	\$ 8,299	\$ 31,048
Jun	30	720	691.20	2.000	1,382.40	2.0	12.0	1,394	2.02	1,381	14,307,840	7,154	1,147,392,000	11,474	\$ 8,032	\$ 30,046
Jul	31	744	714.24	2.000	1,428.48	2.0	12.0	1,440	2.02	1,427	14,784,768	7,392	1,185,638,400	11,856	\$ 8,299	\$ 31,048
Aug	31	744	714.24	2.000	1,428.48	2.0	12.0	1,440	2.02	1,427	14,784,768	7,392	1,185,638,400	11,856	\$ 8,299	\$ 31,048
Sep	30	720	691.20	2.000	1,382.40	2.0	12.0	1,394	2.02	1,381	14,307,840	7,154	1,147,392,000	11,474	\$ 8,032	\$ 30,046
Oct	31	744	714.24	2.000	1,428.48	2.0	12.0	1,440	2.02	1,427	14,784,768	7,392	1,185,638,400	11,856	\$ 8,299	\$ 31,048
Nov	30	720	691.20	2.000	1,382.40	2.0	12.0	1,394	2.02	1,381	14,307,840	7,154	1,147,392,000	11,474	\$ 8,032	\$ 30,046
Dec	31	744	714.24	2.000	1,428.48	2.0	12.0	1,440	2.02	1,427	14,784,768	7,392	1,185,638,400	11,856	\$ 8,299	\$ 31,048
		8,760	8,400.36		16,801			16,945		16,784	173,887,452	86,944	13,944,597,600	139,446	\$ 97,612	\$ 365,164
Mean MW										2.00						

Portland General Electric

Assumptions:

Capacity (Peak) rate at 2/3 of hours (5,600 hrs) and fuel rate at 1/3 of hours (2,800 hrs/yr) for 8,400 hours per year
 Years 19 and 20 replicate last published avoided cost estimates for 2028
 On peak and off peak in mills per kilowatt hour or dollars per MWH
 On peak is 6 am to 10 pm Mondays through Saturdays (4,992 hrs) and off peak is 10 pm to 6 am Monday through Saturday and all day Sunday (3,768)
 2.0 MW capacity begins 2012 - buy-all, sell-all agreement makes ancillary loads purchased at retail
 PGE avoided cost are monthly values averaged annually for peak and off peak
 Sales begin January 2012

Year	On Peak	Hrs. Peak	Peak MWH	Peak Rev	Off Peak	Hrs. Off Pe	Off MWH	Value	Sum MWH	SUM	Mean Rate	
2012	\$ 59.61	4,992	9,984.0	\$ 595,146	\$ 47.61	3,768	7,536.0	\$ 358,789	17,520	\$ 953,935	\$ 54.45	
2013	\$ 93.62	4,992	9,984.0	\$ 934,702	\$ 60.84	3,768	7,536.0	\$ 458,490	17,520	\$ 1,393,192	\$ 79.52	
2014	\$ 92.64	4,992	9,984.0	\$ 924,918	\$ 59.24	3,768	7,536.0	\$ 446,433	17,520	\$ 1,371,350	\$ 78.27	
2015	\$ 91.06	4,992	9,984.0	\$ 909,143	\$ 57.03	3,768	7,536.0	\$ 429,778	17,520	\$ 1,338,921	\$ 76.42	
2016	\$ 91.34	4,992	9,984.0	\$ 911,939	\$ 56.77	3,768	7,536.0	\$ 427,819	17,520	\$ 1,339,757	\$ 76.47	
2017	\$ 93.49	4,992	9,984.0	\$ 933,404	\$ 58.04	3,768	7,536.0	\$ 437,389	17,520	\$ 1,370,794	\$ 78.24	
2018	\$ 96.53	4,992	9,984.0	\$ 963,756	\$ 60.53	3,768	7,536.0	\$ 456,154	17,520	\$ 1,419,910	\$ 81.05	
2019	\$ 100.78	4,992	9,984.0	\$ 1,006,188	\$ 64.09	3,768	7,536.0	\$ 482,982	17,520	\$ 1,489,170	\$ 85.00	
2020	\$ 101.45	4,992	9,984.0	\$ 1,012,877	\$ 64.18	3,768	7,536.0	\$ 483,660	17,520	\$ 1,496,537	\$ 85.42	
2021	\$ 103.81	4,992	9,984.0	\$ 1,036,439	\$ 65.71	3,768	7,536.0	\$ 495,191	17,520	\$ 1,531,630	\$ 87.42	
2022	\$ 106.03	4,992	9,984.0	\$ 1,058,604	\$ 67.21	3,768	7,536.0	\$ 506,495	17,520	\$ 1,565,098	\$ 89.33	
2023	\$ 109.63	4,992	9,984.0	\$ 1,094,546	\$ 69.94	3,768	7,536.0	\$ 527,068	17,520	\$ 1,621,614	\$ 92.56	
2024	\$ 112.83	4,992	9,984.0	\$ 1,126,495	\$ 72.64	3,768	7,536.0	\$ 547,415	17,520	\$ 1,673,910	\$ 95.54	
2025	\$ 115.13	4,992	9,984.0	\$ 1,149,458	\$ 74.06	3,768	7,536.0	\$ 558,116	17,520	\$ 1,707,574	\$ 97.46	
2026	\$ 117.32	4,992	9,984.0	\$ 1,171,323	\$ 75.46	3,768	7,536.0	\$ 568,667	17,520	\$ 1,739,989	\$ 99.31	
2027	\$ 119.55	4,992	9,984.0	\$ 1,193,587	\$ 75.46	3,768	7,536.0	\$ 568,667	17,520	\$ 1,762,254	\$ 100.59	
2028	\$ 121.78	4,992	9,984.0	\$ 1,215,852	\$ 76.89	3,768	7,536.0	\$ 579,443	17,520	\$ 1,795,295	\$ 102.47	
2029	\$ 121.80	4,992	9,984.0	\$ 1,216,051	\$ 78.31	3,768	7,536.0	\$ 590,144	17,520	\$ 1,806,195	\$ 103.09	
2030	\$ 121.80	4,992	9,984.0	\$ 1,216,051	\$ 78.31	3,768	7,536.0	\$ 590,144	17,520	\$ 1,806,195	\$ 103.09	
2031	\$ 121.80	4,992	9,984.0	\$ 1,216,051	\$ 78.31	3,768	7,536.0	\$ 590,144	17,520	\$ 1,806,195	\$ 103.09	
Sum										\$ 27,377,125		
Average										\$ 1,368,856		

Interconnection Agreement Samples

California Feed in Tariff at Market Price Referant for a 20 Year Resource

Assumptions: Uses the 2012, fifteen year California Market Price Referent of 105.07 per MWH to start and a 2% escalation agreement
 Time of Delivery Factors Assume 1.3 of MPR Peak and Super Peak Average (3640 hrs), and .75 Off Peak (4760)
 Peak represents weekdays 6 am to 8 pm and Off-Peak all other hours of 8,400 hour per year - As Per CA MPR Schedules
 Wheeling cost for 2.055 net MWH is \$18 per MWH (Mid valley to Malin at California Oregon Border then to buyer) or and \$14 per MWH (BPA to John Day then to California buyer)
 Sales begin in January 2012

Year	MPR/MWH	With TOD	MWH Peak	Value	Off-Peak	MWH	Value	Sum MWH	SUM Sales	Wheeling Cost	Net Revenue
2012	\$ 105.07	\$ 136.59	3,642.0	\$ 497,464	\$102.443	9,520	\$ 975,260	13,162	\$ 1,472,724	\$ (236,916)	\$ 1,235,808
2013	\$ 107.17	\$ 139.32	3,642.0	\$ 507,414	\$104.492	9,520	\$ 994,765	13,162	\$ 1,502,179	\$ (236,916)	\$ 1,265,263
2014	\$ 109.31	\$ 142.11	3,642.0	\$ 517,562	\$106.582	9,520	\$ 1,014,660	13,162	\$ 1,532,222	\$ (236,916)	\$ 1,295,306
2015	\$ 111.50	\$ 144.95	3,642.0	\$ 527,913	\$108.714	9,520	\$ 1,034,953	13,162	\$ 1,562,867	\$ (236,916)	\$ 1,325,951
2016	\$ 113.73	\$ 147.85	3,642.0	\$ 538,471	\$110.888	9,520	\$ 1,055,653	13,162	\$ 1,594,124	\$ (236,916)	\$ 1,357,208
2017	\$ 116.01	\$ 150.81	3,642.0	\$ 549,241	\$113.106	9,520	\$ 1,076,766	13,162	\$ 1,626,006	\$ (236,916)	\$ 1,389,090
2018	\$ 118.33	\$ 153.82	3,642.0	\$ 560,226	\$115.368	9,520	\$ 1,098,301	13,162	\$ 1,658,527	\$ (236,916)	\$ 1,421,611
2019	\$ 120.69	\$ 156.90	3,642.0	\$ 571,430	\$117.675	9,520	\$ 1,120,267	13,162	\$ 1,691,697	\$ (236,916)	\$ 1,454,781
2020	\$ 123.11	\$ 160.04	3,642.0	\$ 582,859	\$120.029	9,520	\$ 1,142,672	13,162	\$ 1,725,531	\$ (236,916)	\$ 1,488,615
2021	\$ 125.57	\$ 163.24	3,642.0	\$ 594,516	\$122.429	9,520	\$ 1,165,526	13,162	\$ 1,760,042	\$ (236,916)	\$ 1,523,126
2022	\$ 128.08	\$ 166.50	3,642.0	\$ 606,406	\$124.878	9,520	\$ 1,188,836	13,162	\$ 1,795,243	\$ (236,916)	\$ 1,558,327
2023	\$ 130.64	\$ 169.83	3,642.0	\$ 618,534	\$127.375	9,520	\$ 1,212,613	13,162	\$ 1,831,147	\$ (236,916)	\$ 1,594,231
2024	\$ 133.25	\$ 173.23	3,642.0	\$ 630,905	\$129.923	9,520	\$ 1,236,865	13,162	\$ 1,867,770	\$ (236,916)	\$ 1,630,854
2025	\$ 135.92	\$ 176.70	3,642.0	\$ 643,523	\$132.521	9,520	\$ 1,261,602	13,162	\$ 1,905,126	\$ (236,916)	\$ 1,668,210
2026	\$ 138.64	\$ 180.23	3,642.0	\$ 656,394	\$135.172	9,520	\$ 1,286,835	13,162	\$ 1,943,228	\$ (236,916)	\$ 1,706,312
2027	\$ 141.41	\$ 183.83	3,642.0	\$ 669,522	\$137.875	9,520	\$ 1,312,571	13,162	\$ 1,982,093	\$ (236,916)	\$ 1,745,177
2028	\$ 144.24	\$ 187.51	3,642.0	\$ 682,912	\$140.633	9,520	\$ 1,338,823	13,162	\$ 2,021,735	\$ (236,916)	\$ 1,784,819
2029	\$ 147.12	\$ 191.26	3,642.0	\$ 696,570	\$143.445	9,520	\$ 1,365,599	13,162	\$ 2,062,169	\$ (236,916)	\$ 1,825,253
2030	\$ 150.07	\$ 195.09	3,642.0	\$ 710,502	\$146.314	9,520	\$ 1,392,911	13,162	\$ 2,103,413	\$ (236,916)	\$ 1,866,497
2031	\$ 153.07	\$ 198.99	3,642.0	\$ 724,712	\$149.240	9,520	\$ 1,420,769	13,162	\$ 2,145,481	\$ (236,916)	\$ 1,908,565
Sum								236,916	\$ 31,534,430	\$ (4,264,488)	\$ 27,269,942
Average									\$ 1,576,721	\$ (213,224)	\$ 1,363,497

Portland General Electric Avoided Costs												
Fixed Price Option												
On-Peak Forecast (\$/MWH)												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	N/A	N/A	N/A	N/A	N/A	N/A	N/A	\$ 32.71	\$ 31.59	\$ 32.46	\$ 41.21	\$ 50.34
2010	\$ 51.25	\$ 47.75	\$ 42.75	\$ 41.00	\$ 36.00	\$ 33.25	\$ 53.75	\$ 58.25	\$ 57.75	\$ 53.75	\$ 56.00	\$ 59.25
2011	\$ 60.30	\$ 56.80	\$ 53.55	\$ 47.55	\$ 40.80	\$ 39.55	\$ 64.05	\$ 66.80	\$ 63.55	\$ 58.80	\$ 62.05	\$ 65.05
2012	\$ 62.07	\$ 57.81	\$ 51.71	\$ 49.58	\$ 43.48	\$ 40.13	\$ 65.12	\$ 70.61	\$ 70.00	\$ 65.12	\$ 67.86	\$ 71.83
2013	\$ 97.44	\$ 97.41	\$ 95.83	\$ 90.96	\$ 90.67	\$ 91.16	\$ 91.72	\$ 92.21	\$ 92.38	\$ 92.90	\$ 94.45	\$ 96.26
2014	\$ 96.31	\$ 96.28	\$ 94.76	\$ 90.04	\$ 89.79	\$ 90.26	\$ 90.83	\$ 91.27	\$ 91.46	\$ 91.99	\$ 93.47	\$ 95.24
2015	\$ 94.54	\$ 94.51	\$ 93.07	\$ 88.60	\$ 88.36	\$ 88.81	\$ 89.35	\$ 89.76	\$ 89.94	\$ 90.45	\$ 91.85	\$ 93.52
2016	\$ 94.77	\$ 94.74	\$ 93.32	\$ 88.90	\$ 88.66	\$ 89.11	\$ 89.64	\$ 90.05	\$ 90.23	\$ 90.73	\$ 92.12	\$ 93.77
2017	\$ 97.00	\$ 96.97	\$ 95.52	\$ 90.99	\$ 90.75	\$ 91.21	\$ 91.75	\$ 92.17	\$ 92.35	\$ 92.86	\$ 94.28	\$ 95.97
2018	\$ 100.22	\$ 100.19	\$ 98.67	\$ 93.92	\$ 93.66	\$ 94.14	\$ 94.71	\$ 95.15	\$ 95.34	\$ 95.88	\$ 97.37	\$ 99.15
2019	\$ 104.73	\$ 104.70	\$ 103.07	\$ 97.98	\$ 97.71	\$ 98.22	\$ 98.83	\$ 99.30	\$ 99.51	\$ 100.08	\$ 101.68	\$ 103.58
2020	\$ 105.39	\$ 105.35	\$ 103.73	\$ 98.65	\$ 98.38	\$ 98.89	\$ 99.50	\$ 99.97	\$ 100.17	\$ 100.75	\$ 102.34	\$ 104.23
2021	\$ 107.84	\$ 107.81	\$ 106.14	\$ 100.94	\$ 100.67	\$ 101.19	\$ 101.81	\$ 102.29	\$ 102.50	\$ 103.09	\$ 104.72	\$ 106.66
2022	\$ 110.17	\$ 110.13	\$ 108.43	\$ 103.10	\$ 102.82	\$ 103.35	\$ 103.99	\$ 104.49	\$ 104.70	\$ 105.30	\$ 106.97	\$ 108.96
2023	\$ 113.96	\$ 113.92	\$ 112.13	\$ 106.56	\$ 106.26	\$ 106.82	\$ 107.49	\$ 108.01	\$ 108.23	\$ 108.86	\$ 110.61	\$ 112.69
2024	\$ 117.35	\$ 117.31	\$ 115.45	\$ 109.62	\$ 109.31	\$ 109.89	\$ 110.59	\$ 111.13	\$ 111.37	\$ 112.03	\$ 113.85	\$ 116.03
2025	\$ 119.74	\$ 119.70	\$ 117.80	\$ 111.86	\$ 111.55	\$ 112.14	\$ 112.85	\$ 113.41	\$ 113.65	\$ 114.32	\$ 116.18	\$ 118.40
2026	\$ 122.01	\$ 121.97	\$ 120.04	\$ 113.99	\$ 113.66	\$ 114.27	\$ 115.00	\$ 115.56	\$ 115.80	\$ 116.49	\$ 118.38	\$ 120.64
2027	\$ 124.33	\$ 124.29	\$ 122.32	\$ 116.15	\$ 115.82	\$ 116.44	\$ 117.18	\$ 117.75	\$ 118.00	\$ 118.70	\$ 120.63	\$ 122.93
2028	\$ 126.65	\$ 126.61	\$ 124.60	\$ 118.32	\$ 117.98	\$ 118.61	\$ 119.37	\$ 119.95	\$ 120.20	\$ 120.91	\$ 122.88	\$ 125.23

Mean

\$ 59.61
\$ 93.62
\$ 92.64
\$ 91.06
\$ 91.34
\$ 93.49
\$ 96.53
\$ 100.78
\$ 101.45
\$ 103.81
\$ 106.03
\$ 109.63
\$ 112.83
\$ 115.13
\$ 117.32
\$ 119.55
\$ 121.78

Portland General Electric Avoided Costs

Interconnection Agreement Samples

Fixed Price Option													
Off-Peak Forecast (\$/MWH)													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Mean
2009	N/A	N/A	N/A	N/A	N/A	N/A	N/A	\$ 26.59	\$ 27.21	\$ 27.71	\$ 35.21	\$ 43.71	
2010	\$ 44.75	\$ 42.75	\$ 37.75	\$ 34.75	\$ 26.25	\$ 23.75	\$ 40.25	\$ 44.00	\$ 41.75	\$ 42.75	\$ 48.75	\$ 55.25	
2011	\$ 55.30	\$ 51.80	\$ 48.05	\$ 36.80	\$ 29.80	\$ 27.30	\$ 45.30	\$ 50.55	\$ 50.30	\$ 49.80	\$ 53.80	\$ 57.05	
2012	\$ 53.00	\$ 50.62	\$ 44.66	\$ 41.08	\$ 30.95	\$ 27.97	\$ 47.64	\$ 52.11	\$ 49.42	\$ 50.62	\$ 57.77	\$ 65.52	\$ 47.61
2013	\$ 64.67	\$ 64.64	\$ 63.06	\$ 58.19	\$ 57.89	\$ 58.39	\$ 58.94	\$ 59.44	\$ 59.60	\$ 60.13	\$ 61.68	\$ 63.49	\$ 60.84
2014	\$ 62.91	\$ 62.88	\$ 61.37	\$ 56.64	\$ 56.39	\$ 56.86	\$ 57.43	\$ 57.87	\$ 58.06	\$ 58.60	\$ 60.08	\$ 61.84	\$ 59.24
2015	\$ 60.51	\$ 60.48	\$ 59.04	\$ 54.57	\$ 54.33	\$ 54.78	\$ 55.32	\$ 55.73	\$ 55.91	\$ 56.42	\$ 57.82	\$ 59.49	\$ 57.03
2016	\$ 60.20	\$ 60.17	\$ 58.76	\$ 54.33	\$ 54.10	\$ 54.54	\$ 55.07	\$ 55.48	\$ 55.66	\$ 56.16	\$ 57.55	\$ 59.20	\$ 56.77
2017	\$ 61.55	\$ 61.52	\$ 60.07	\$ 55.55	\$ 55.30	\$ 55.76	\$ 56.30	\$ 56.72	\$ 56.90	\$ 57.42	\$ 58.83	\$ 60.52	\$ 58.04
2018	\$ 64.22	\$ 64.19	\$ 62.66	\$ 57.91	\$ 57.66	\$ 58.13	\$ 58.70	\$ 59.15	\$ 59.34	\$ 59.88	\$ 61.37	\$ 63.14	\$ 60.53
2019	\$ 68.04	\$ 68.01	\$ 66.38	\$ 61.29	\$ 61.02	\$ 61.53	\$ 62.14	\$ 62.61	\$ 62.82	\$ 63.39	\$ 64.99	\$ 66.89	\$ 64.09
2020	\$ 68.12	\$ 68.08	\$ 66.46	\$ 61.38	\$ 61.11	\$ 61.62	\$ 62.23	\$ 62.70	\$ 62.91	\$ 63.48	\$ 65.07	\$ 66.97	\$ 64.18
2021	\$ 69.74	\$ 69.71	\$ 68.04	\$ 62.84	\$ 62.57	\$ 63.09	\$ 63.71	\$ 64.20	\$ 64.40	\$ 64.99	\$ 66.62	\$ 68.56	\$ 65.71
2022	\$ 71.34	\$ 71.31	\$ 69.60	\$ 64.28	\$ 63.99	\$ 64.53	\$ 65.17	\$ 65.66	\$ 65.88	\$ 66.48	\$ 68.15	\$ 70.14	\$ 67.21
2023	\$ 74.27	\$ 74.23	\$ 72.45	\$ 66.87	\$ 66.57	\$ 67.13	\$ 67.80	\$ 68.32	\$ 68.54	\$ 69.18	\$ 70.92	\$ 73.01	\$ 69.94
2024	\$ 77.17	\$ 77.13	\$ 75.26	\$ 69.44	\$ 69.12	\$ 69.71	\$ 70.41	\$ 70.95	\$ 71.18	\$ 71.84	\$ 73.67	\$ 75.84	\$ 72.64
2025	\$ 78.66	\$ 78.62	\$ 76.72	\$ 70.79	\$ 70.47	\$ 71.06	\$ 71.78	\$ 72.33	\$ 72.57	\$ 73.24	\$ 75.10	\$ 77.32	\$ 74.06
2026	\$ 80.16	\$ 80.12	\$ 78.18	\$ 72.13	\$ 71.81	\$ 72.41	\$ 73.14	\$ 73.70	\$ 73.94	\$ 74.63	\$ 76.53	\$ 78.78	\$ 75.46
2027	\$ 81.68	\$ 81.64	\$ 79.66	\$ 73.50	\$ 73.17	\$ 73.78	\$ 74.52	\$ 75.10	\$ 75.35	\$ 76.04	\$ 77.98	\$ 80.28	\$ 76.89
2028	\$ 83.19	\$ 83.15	\$ 81.14	\$ 74.85	\$ 74.52	\$ 75.15	\$ 75.90	\$ 76.49	\$ 76.74	\$ 77.45	\$ 79.42	\$ 81.77	\$ 78.31

Portland General Electric Company
P.U.C. Oregon No. E-18
Advice No. 09-16
Issued July 10, 2009

SCHEDULE 201
QUALIFYING FACILITY 10 MW or LESS