Introduction

In support of our development, production and sales of biomass-to-energy systems, Biomass Energy

electrical energy. Using a 300 kW electrical generator driven by a reciprocating gas fired engine, the system produces over 1 MWh of electrical energy for every ton of biomass material converted. In addition, another 2 MWh of thermal energy is produced from that same ton of biomass. Much

MWh of thermal energy can be used for thermal applications.

Gasification

Gasification coverts biomass into a burnable gas, called producer gas, using a closed process. Since the system is closed, there are no emissions from the gasification process. The burnable gas produced is cleaned and cooled, removing tars and particulates from the gas before it is used in an engine. As long as the biomass is not contaminated with sulfur containing waste, the final

2 to plant material and releases oxygen from water, the oxygen used and the
CO_2 released during combustion of the producer gas make no net change to the atmosphere.

Performance

Depending on the efficiency of the generating system and the energy content of the biomass, Biomass Energy Systems gasifiers will typically convert 1,500 lbs of dried (15-16% water content l energy. Since about 95% of the
carbon in the biomass is converted to producer gas, one ton of 15-16% water content biomass will

The carbon ash can be reprocessed in the gasifier, adding to its fuel. The carbon can also be activated and used for filtering applications, or returned to the land, effectively sequestering the carbon instead of returning it to the atmosphere as CO_2.

Operational Considerations

The gasification process can startup in less than 15 minutes when the gasifier has been operated

power generation system to produce dispatchable electrical power. The system can run continuously or be easily operated to meet scheduled power needs. With our rapid startup capability, a system with several gasifiers can also meet varying power needs as they come on-line. In such a system,

gasifiers run 24 hours per day,
but not all applications can support such full operation. Since the Biomass Energy Systems gasifiers

power requirements.

Plant Design Considerations

The Biomass Energy Systems gasifier utilizes biomass that has been preprocessed into physically

gasifier. Therefore the entire biomass-to-power generation system consists of three major areas.

Material Handling	- Drying, cubing, short term storage, conveying biomass fuel
Gasification	- Production of burnable producer gas, filtering of producer gas
Electrical Generation	- Combustion of producer gas in engine to drive electrical generator, recovery of waste heat from engine exhaust for drying biomass fuel.

The material handling and preprocessing dries the biomass material to 15-16% water content use in the gasifier. Therefore, drying
and cubing can be operated separately from the gasification process, allowing the two areas to operate on different schedules. Similarly, the size of the equipment needed for drying and cubing can be determined to optimize the cost and scheduling of the preprocessing operation. One dryer

hour operation.

Although the material preprocessing system runs as a batch operation, the gasification system can

bins into the gasifier. The gasifier is fully monitored and controlled by a microprocessor based control system. New fuel is automatically fed into the gasifier as the biomass is converted and the

bottom of the gasifier, cooled and stored in bags.

Power generation is accomplished with a generator driven by a reciprocating or turbine engine. The producer gas output of several gasifiers can be combined to fuel one engine, but operation

during planned or unplanned gasifier shut downs. Reduction in producer gas flow to the engine simply reduces the power available from the electrical generator. Heat can be recovered from the exhaust and from the cooling of the engine. This heat can be used to dry the biomass material as it is brought into the facility. The heat from the exhaust of several engines can also be used to boil water and run a separate steam cycle electrical generator, adding to the electrical output.

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What is Gasification of Biomass

Gasification turns solid or liquid biomass material into a clean burning gas fuel. How does this

and char. The gases with lower ignition temperatures then begin to burn, combining with any oxygen present and generating more heat. As the temperature of the biomass increases, carbon char freed

however, the amount of oxygen is restricted so that the gasses that are produced are not allowed to continue to fully combust. Instead, they are collected, cooled and cleaned.

The gas produced through this gasification process is known as producer gas. The burnable

carbon dioxide, nitrogen and water vapor. Producer gas typically has an energy density of approximately 200 BTU/cu ft, which is about one fifth of the energy density of natural gas. However, since these gases exist in the gasification reaction at elevated temperatures, some of the energy of that reaction

The chemistry of the gasification reaction is a combination of reactions that both produce heat

from this process and effectively store it chemically as increased energy density of the producer gas. The "water gas shift reaction" is typical of these enhancements. This reaction uses the heat

added hydrogen. This enhancement is an efficient use of the thermal energy from the gasification reaction that would otherwise be lost as the producer gas is cooled.

BIOENERGY systems inc.

Why Gasify Biomass Instead of Just Burning it?

Gasification of biomass produces a clean burning gas fuel. But why not just burn the biomass fficiency, convenience of use and
environmental pollution.

Efficiency

The producer gas from the gasification process contains only the energy that was contained in the original biomass material. The efficiency of the conversion of this energy from the original biomass into the producer gas is above 90%. Depending on the age and state of the boiler, when biomass is burned directly in a biomass fired boiler much of the energy produced from the combustion of

50% more efficient at converting the energy contained in the biomass into a useful form. This increased efficiency is due in large part to the closed process design, where only a small amount of the process heat escapes.

Convenience of Use and Efficiency

Producer gas can be readily used to drive both reciprocating and gas turbine engines. Since the ves a more efficient conversion to
mechanical energy than the use of steam turbines where the steam is injected at high temperature

the increased efficiency of a gas turbine over a steam turbine, the energy converted from the biomass through gasification and the use of a gas turbine engine can increase overall efficiency by 100% over a biomass fired boiler and steam turbine. Therefore, gasification derived producer gas is both efficient use of the energy than
direct firing of the biomass.

Environmental Pollution

As biomass is heated for combustion or gasification, many hydrocarbons are produced as the material

ce efficiency and add cost to the
process. Since gasification is a closed process, these pollutants are broken down within the process and then what is left is filtered out of the gas. No efficiency is lost and the gas filtering is done in a closed system. There is no stack or any significant emissions from the gasification process.

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What is a Downdraft Gasifier?

Thermal gasification of biomass is accomplished in a closed system to allow the producer gas to be collected and extracted. However, the biomass can be introduced and reacted in the vessel using different approaches. A downdraft gasifier feeds the biomass into the top of the reactor, drawing air in with the feed and down through the reactor. After the air and biomass react, the producer gas is drawn out and the residual, unreacted carbon is removed from the bottom of the reactor. The amount of oxygen supplied to the reaction is controlled through limiting the amount of air drawn in with the feed by metering the amount of gas drawn out of the reactor. The feed rate and the gas flows are balanced to produce a gas with the highest energy density.

The downdraft gasifier has a simple and stable design, making it effective for small, modular applications. Since the biomass feed creates an insulating bed on the top surface of the reaction

in the process. Also, if the bed is too large in diameter, the flow of the biomass down through the reaction area can develop unstable patterns. However, if the system design deals with these issues correctly, the downdraft gasifier is the least complicated approach to gasify biomass.

Other gasifier design approaches include pressurized vessels and fluidized beds. These approaches

will allow. However, developing and maintaining the fluidized bed requires considerable ancillary equipment to blow gas through and fluidize the bed. The pressurized vessel also requires the

The downdraft gasifier design is effective for modular units that are up to approximately 1 MW of electrical output each. Since the producer gas output from the gasifier can also be used for thermal

BIOENERGY systems inc.

What do BioEnergy Systems gasifiers produce?

Bio Energy Systems downdraft gasifiers convert biomass into a gas that is a combination of hydrogen,

producer gas is shown in the table below.

Gas Component	Percent of Total
Hydrogen	31%
Carbon Monoxide	20%
Methane	6%
Propane	0.5%

With these levels of combustible gases, the producer gas contains about 225 BTU/cu ft. Between 90% and 95% of the energy contained in the biomass is converted into energy available

The Bio Energy Systems gasifiers are fully automated systems. Operational and process parameters

can start up and produce gas in 15 to 30 minutes. Similarly, it can shut down from stable operations in just 15 minutes. During the stable operation between start up and shut down, the system

There is no stack on the gasifier since there are no atmospheric emissions from the gasification

of the gasifier. Residual tars and particulates that are filtered out of the producer gas stream are injected back into the gasification process to be broken down and destroyed. Since the gasifier

RJ 1000 Specifications

- Fully automated operation
- Microprocessor based control system
- Combined Heat and Power (CHP) Co-Gen capability
- Can use a variety of biomass fuels (cubed hog fuel, wood pellets, cubed MSW)
- Electrical power: capable of 1 MWe
- Thermal power: 10 million BTU/hr
- Gas: HHV ~ 225 BTU/cu ft
- Fuel Conversion: ~1,500 lbs of evenly compressed fuel produces 1MWhe at 33% efficient generator
- Full cold start up: 30 minutes
- Warm startup: 15 minutes
- Turn down ratio: 5 to 1
- Gas composition: O_2 0.5%, H_2 31%, CO 20%, CH_4 6%, CO_2 20%, Balance is N_2

Appendix IV

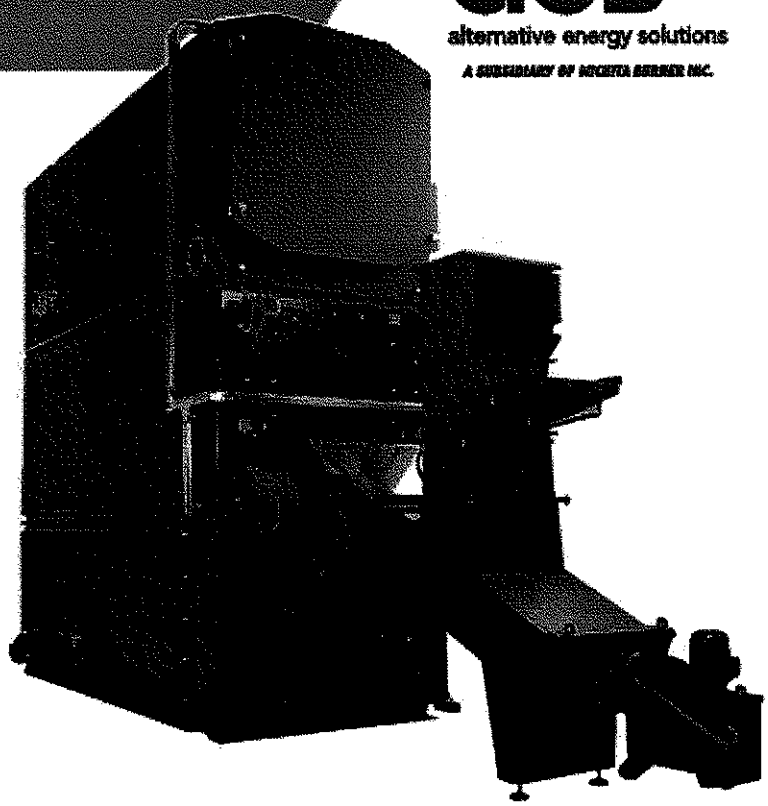
Alternative Energy Solutions Presentation

Modular Biomass Gasification

Proven Biomass Energy Systems By Alternative Energy Solutions

Reduce or remove your dependence on costly fossil fuel

aes
alternative energy solutions
A SUBSIDIARY OF KRUETA BERNER INC.



AES Uniconfort Global G Series

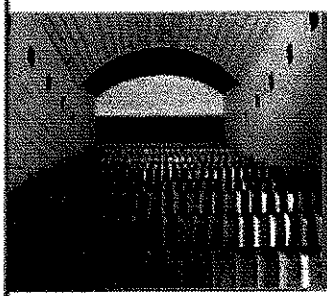
Alternative Energy Solutions offers the premiere modular

BENEFIT FROM MODULARITY

Downtime is not an option, so

Hot Water @ 203° F | 290 psig Superheated Water up to 302° F & 157 psig Saturated Steam up to 20 bar | and/or Electricity up to 1 mWe*

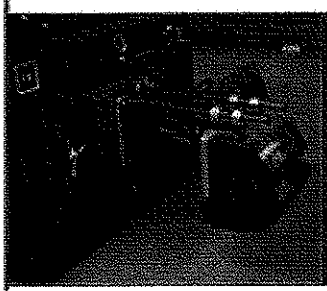
*per boiler, when paired with steam-driven electricity generating equipment



A Superior Grate System

The inclined moving grate provides for gentile agitation of high

compartment control the grate temperatures. Distributed primary, secondary and tertiary air offers complete control of combustion modulation.



Designed For Performance

The Uniconfort is a feat of engineering that is over 50 years in the making. Many generations of product design and improvement have resulted in a highly automated, efficient, and user-friendly system that makes operating a biomass boiler nearly as simple as running a traditionally fueled system.

Product Features:

Versatile Fuel Handling

- Utilize a wide range of biomass fuels High
- moisture fuels up to 120% dry base
- Accepts fuel sized up to 12" x 2" x 2"
- Accepts dirt content up to 10%
- High ash content tolerances
-

Automated Operation

- PLC Panel w/ Remote Monitoring
-
- Automatic ash extraction
- Automatic soot blower (optional)

Durable, Quality Components

- Stainless steel water cooled moving grates*
- Plate steel shell
- Hand laid fireblock refractory
- Retractable burner assembly

** Standard on G300,G400,G500 ; Optional on other models*

uniconfort

Currently, there are over 3000 Uniconfort

Information subject to change without prior notification.

100 S. Main Suite 520 | Wichita, KS 67202 | 316.201.4143 | info@aesenergy.com | www.aesenergy.net

Cleaner Combustion Through Gasification

By using Gasification with Vertically Integrated Combustion (GVIC) our boilers boast extremely low emissions, and high efficiency (80-

combustion chamber that increases efficiency and eliminates klinkering and slagging.

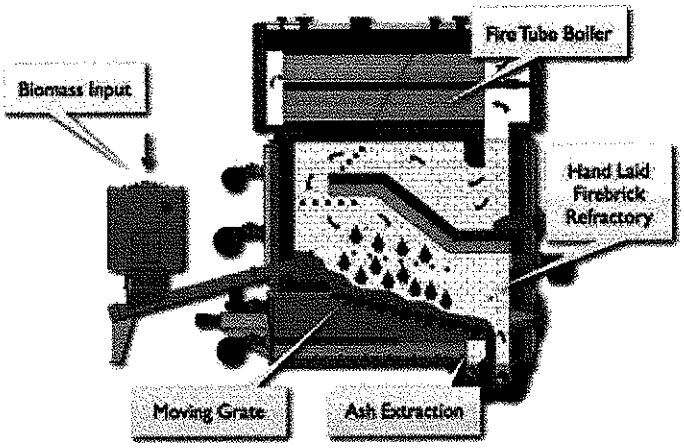


Figure 1: Uniconfort Global Series Components

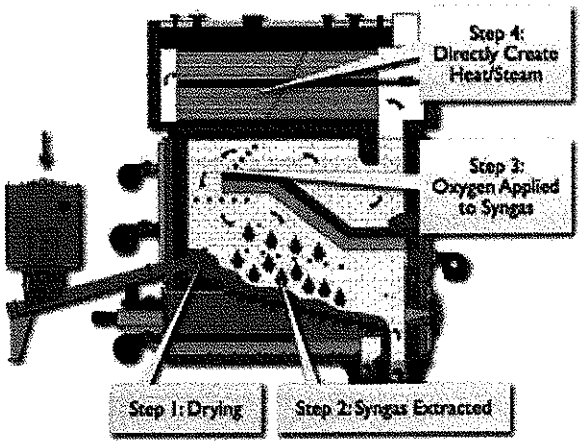


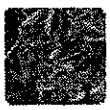
Figure 2: Gasification & Vertically Integrated Combustion

AES UNICONFORT GLOBAL G

Model	Thermal Output	Steam Output	Dimensions (feet) Boiler Only			Boiler Weight	Fuel Consumed (7500 btu/lb, 20% moisture)	
	mm btu/h	lb/hr	L	W	H	lbs	lbs/hr	tons/hr
G-30	1.18	1102	8.85	5.00	13.2	33,020	160	0.08
G-60	2.37	2204	11.50	5.60	13.4	41,800	316	0.14
G-90	3.57	3306	13.12	6.02	16	50,419	476	0.24
G-120	4.75	4408	14.76	6.02	17.2	57,254	560	0.28
G-150	5.95	5,511	14.76	6.73	18	65,631	793	0.39
G-180	7.14	6,614	16.40	6.73	20	73,590	952	0.48
G-240	9.82	8,819	18.00	6.95	21	84,833	1,476	0.74
G-300	11.87	11,023	19.70	6.95	22	95,195	1,582	0.79
G-400	15.83	14,550	21.33	7.55	24	106,181	2,110	1.05
G-500	19.84	18,364	24.60	7.55	25.9	144,089	2,645.0	1.20
600 +	Contact Alternative Energy Solutions for information on larger models							

Electrical Generation Capabilities Range From 100kWe - 1 mWe per boiler pending configuration

What Is Your Opportunity Fuel?



Wood
Sawdust, limbs, bark, trimmings mulch, remnants, debris

Agriculture
Chaff, hulls, stalks, midds shells, skins, husks, algae

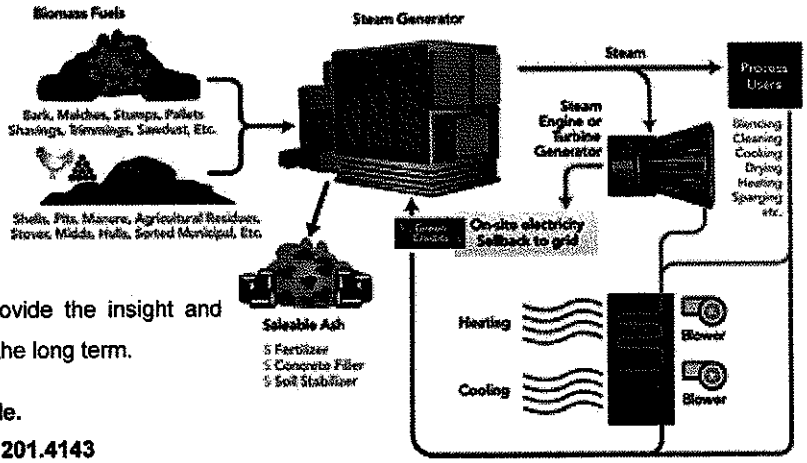
Animal & Municipal Waste
Manure, litter, washdown, organic municipal solids

Industrial & Commercial Waste
Paper, crates, pallets, pulp fats, oils, sludges, remnants

Turnkey System Integration

Alternative Energy Solutions offers turnkey modular systems

years of experience to each project-ensuring that your



AES' experts remain involved with your operations and provide the insight and expertise to keep your biomass system running at its best on the long term.

Biomass energy has never been simpler or more accessible.
Call Alternative Energy Solutions today to learn more. 316.201.4143

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Appendix V

Pacific Power Schedule 37

Available

To owners of Qualifying Facilities making sales of electricity to the Company in the State of Oregon.

Applicable

For power purchased from Qualifying Facilities with a nameplate capacity of 10,000 kW or less or that, 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, has a nameplate capacity of 10,000 kW or less. Owners of these Qualifying Facilities will be required to enter into a written power sales contract with the Company.

Definitions

Cogeneration Facility

A facility which produces electric energy together with steam or other form of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes through the sequential use of energy.

Qualifying Facilities

Qualifying cogeneration facilities or qualifying small power production facilities within the meaning of section 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. 796 and 824a-3.

Small Power Production Facility

A facility which produces electric energy using as a primary energy source biomass, waste, renewable resources or any combination thereof and has a power production capacity which, together with other facilities located at the same site, is not greater than 80 megawatts.

On-Peak Hours or Peak Hours

On-peak hours are defined as 6:00 a.m. to 10:00 p.m. Pacific Prevailing Time Monday through Saturday, excluding NERC holidays.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005, the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April and for the period between the last Sunday in October and the first Sunday in November.

Off-Peak Hours

All hours other than On-Peak.

West Side Gas Market Index

The monthly indexed gas price shall be the average of the price indexes published by Platts in "Inside FERC's Gas Market Report" monthly price report for Northwest Pipeline Corp. Rock Mountains, Northwest Pipeline Corp. Canadian Border, and Rockies/Northwest Stanfield, OR.

Excess Output

Excess output shall mean any increment of Net Output delivered at a rate, on an hourly basis, exceeding the Facility Nameplate Capacity. PacifiCorp shall pay Seller the Off-peak Price as described and calculated under pricing option 5 for all Excess Output.

(Continued)

Same Site
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.

Person(s) or Affiliated Person(s):
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. 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. 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 in or 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.

Shared Interconnection and Infrastructure:
QFs otherwise meeting the 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 shall be presented to the Commission for resolution.

(Continued)

Pricing Options

1. Fixed Avoided Cost Prices

Prices are fixed at the time that the contract is signed by both the Qualifying Facility and the Company and will not change during the term of the contract. Fixed Avoided Cost Prices are available for a contract term of up to 15 years and prices under a longer term contract (up to 20 years) will thereafter be under either Banded Gas Market Indexed Avoided Cost Prices or Gas Market Indexed Avoided Cost Prices.

2. Gas Market Indexed Avoided Cost Prices

Fixed prices apply during the resource sufficiency period (2007 through 2011), thereafter a portion of avoided cost prices are indexed to actual monthly West Side Gas Market Index prices. The remaining portion of avoided cost prices will be fixed at the time that the contract is signed by both the Qualifying Facility and the Company and will not change during the term of the contract. Prices are available for a term of up to 20 years.

3. Banded Gas Market Indexed Avoided Cost Prices

Fixed prices apply during the resource sufficiency period (2007 through 2011), thereafter a portion of avoided cost prices are indexed to actual monthly West Side Gas Market Index prices. The remaining portion of avoided cost prices will be fixed at the time that the contract is signed by both the Qualifying Facility and the Company and will not change during the term of the contract. The gas indexed portion of the avoided cost prices are banded to limit the amount that prices can vary with changes in gas prices. Prices are available for a term of up to 20 years.

4. Firm Market Indexed Avoided Cost Prices

Firm market index avoided cost prices are available to Qualifying Facilities that contract to deliver firm power. Monthly on-peak / off-peak prices paid are a blending of Dow Jones Index Firm day-ahead Mid-Columbia, California Oregon Border (COB), Four Corners and Palo Verde on-peak and off-peak prices. The monthly blending matrix is available upon request.

5. Non-firm Market Index Avoided Cost Prices

Non- Firm market index avoided cost prices are available to Qualifying Facilities that do not elect to provide firm power. Qualifying Facilities taking this option will have contracts that do not include minimum delivery requirements, default damages for construction delay, for under delivery or early termination, or default security for these purposes. Monthly On-Peak / Off-Peak prices paid are a blending of Dow Jones Index Non-firm day-ahead Mid-Columbia, California Oregon Border (COB), Four Corners and Palo Verde on-peak and off-peak prices. The monthly blending matrix is available upon request.

(Continued)

Monthly Payments

A Qualifying Facility shall select the option of payment at the time of signing the contract under one of three Pricing Options as specified above. Once an option is selected the option will remain in effect for the duration of the Facility's contract.

Fixed Avoided Cost Prices

In accordance with the terms of a contract with a Qualifying Facility, the Company shall pay for all separately metered kilowatt-hours of On-Peak and Off-Peak generation at the fixed prices as provided in this tariff. The definition of On-Peak and Off-Peak is as defined in the definitions section of this tariff.

Gas Market Indexed Avoided Cost Prices

In accordance with the terms of a contract with a Qualifying Facility, the Company shall pay for all separately metered kilowatt-hours of On-Peak and Off-Peak generation at On-Peak and Off-Peak prices calculated each month.

To calculate the Off-Peak price, multiply the West Side Gas Market Index price in $/MMBtu by 0.727 to get actual gas price in cents/kWh. The Off-Peak Energy Adder is added to the actual gas price to get the Off-Peak Price.

The On-Peak price is the Off-Peak price plus the On-Peak Capacity Adder.

Banded Gas Indexed Avoided Cost Prices

In accordance with the terms of a contract with a Qualifying Facility, the Company shall pay for all separately metered kilowatt-hours of On-Peak and Off-Peak generation at On-Peak and Off-Peak prices calculated each month.

To calculate the Off-Peak price, multiply the West Side Gas Market Index price in $/MMBtu by 0.727 to get actual gas price in cents/kWh. This price is banded such that the actual gas price shall be no lower than the Gas Market Index Floor nor greater than the Gas Market Index Ceiling as listed in the price section of this tariff. The Off-Peak Energy Adder is added to the actual gas price to get the Off-Peak Price.

The On-Peak price is the Off-Peak price plus the On-Peak Capacity Adder.

Firm Market Indexed and Non-firm Market Index Avoided Cost Prices

In accordance with the terms of a contract with a Qualifying Facility, the Company shall pay for all separately metered kilowatt-hours of On-Peak and Off-Peak generation at the market prices calculated at the time of delivery. The definition of On-Peak and Off-Peak is as defined in the definitions section of this tariff.

(Continued)

Avoided Cost Prices

Pricing Option 1 - Fixed Avoided cost Prices ¢/kWh

Deliveries During Calendar Year	On-Peak Energy Price (a)	Off-Peak Energy Price (b)
2007	6.65	5.56
2008	7.06	5.70
2009	7.11	5.62
2010	7.21	5.59
2011	7.16	5.42
2012	7.68	5.86
2013	7.72	5.86
2014	7.95	6.06
2015	8.25	6.32
2016	8.40	6.44
2017	8.55	6.55
2018	8.69	6.66
2019	8.86	6.78
2020	9.03	6.91
2021	9.01	6.86
2022	9.03	6.83
2023	9.06	6.82

(Continued)

Avoided Cost Prices (Continued)

Pricing Option 2 - Gas Market Indexed Avoided Cost Prices ¢/kWh

Deliveries During Calendar Year	Fixed Prices		Gas Market Index		Forecast West Side Gas Market Index Price (2)	Estimated Prices (3)	
	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Capacity Adder (1)	Off-Peak Energy Adder	$/MMBtu	On-Peak Energy Price	Off-Peak Energy Price
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
			Avoided Firm Capacity Costs / (0.876 * 85.4% * 57%)	Total Avoided Energy Costs - ((e) * 0.727)		(g) + (c)	((e) * 0.727) + (d)
2007	6.65	5.56					
2008	7.06	5.70					
2009	7.11	5.62	Market Based Prices 2007 through 2011				
2010	7.21	5.59					
2011	7.16	5.42					
2012			1.82	0.50	$7.37	7.68	5.86
2013			1.85	0.51	$7.36	7.72	5.86
2014			1.89	0.52	$7.62	7.95	6.06
2015			1.93	0.54	$7.96	8.25	6.32
2016			1.96	0.55	$8.10	8.40	6.44
2017			2.00	0.56	$8.24	8.55	6.55
2018			2.04	0.56	$8.38	8.69	6.66
2019			2.08	0.57	$8.54	8.86	6.78
2020			2.12	0.59	$8.70	9.03	6.91
2021			2.16	0.59	$8.62	9.01	6.86
2022			2.20	0.61	$8.56	9.03	6.83
2023			2.24	0.61	$8.54	9.06	6.82
2024			2.28	0.62	$8.45	9.04	6.76
2025			2.32	0.63	$8.38	9.04	6.72
2026			2.37	0.64	$8.30	9.04	6.67
2027			2.41	0.65	$8.32	9.11	6.70
2028			2.46	0.66	$8.38	9.21	6.75

(1) Avoided Firm Capacity Costs are equal to the fixed costs of a SCCT as identified in the Company's 2007 IRP.

(2) A heat rate of 0.727 is used to adjust gas prices from $/MMBtu to ¢/kWh

(3) Estimated avoided cost prices based upon forecast West Side Gas Market Index prices.
Actual prices will be calculated each month using actual index gas prices.

(Continued)

Avoided Cost Prices (Continued)

Pricing Option 3 - Banded Gas Market Indexed Avoided Cost Prices ¢/kWh

Deliveries During Calendar Year	Fixed Prices		Banded Gas Market Index				Forecast West Side Gas Market Index Price (2)	Estimated Prices (3)	
	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Capacity Adder (1)	Off-Peak Energy Adder	Gas Market Index Floor 90%	Gas Market Index Ceiling 110%	$/MMBtu	On-Peak Energy Price	Off-Peak Energy Price
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
			Avoided Firm Capacity Costs / (0.876 * 85.4% * 57%)	Total Avoided Energy Costs - ((e) * 0.727)	(g) * 0.727 * 90%	(g) * 0.727 * 110%		(i) + (c)	MIN(MAX(((g) * 0.727), (e)), (f)) + (d)
2007	6.65	5.56							
2008	7.06	5.70							
2009	7.11	5.62	Market Based Prices 2007 through 2011						
2010	7.21	5.59							
2011	7.16	5.42							
2012			1.82	0.50	4.82	5.89	$7.37	7.68	5.86
2013			1.85	0.51	4.82	5.89	$7.36	7.72	5.86
2014			1.89	0.52	4.99	6.09	$7.62	7.95	6.06
015			1.93	0.54	5.21	6.37	$7.96	8.25	6.32
2016			1.96	0.55	5.30	6.48	$8.10	8.40	6.44
2017			2.00	0.56	5.39	6.59	$8.24	8.55	6.55
2018			2.04	0.56	5.48	6.70	$8.38	8.69	6.66
2019			2.08	0.57	5.59	6.83	$8.54	8.86	6.78
2020			2.12	0.59	5.69	6.96	$8.70	9.03	6.91
2021			2.16	0.59	5.64	6.89	$8.62	9.01	6.86
2022			2.20	0.61	5.60	6.85	$8.56	9.03	6.83
2023			2.24	0.61	5.59	6.83	$8.54	9.06	6.82
2024			2.28	0.62	5.53	6.76	$8.45	9.04	6.76
2025			2.32	0.63	5.48	6.70	$8.38	9.04	6.72
2026			2.37	0.64	5.43	6.64	$8.30	9.04	6.67
2027			2.41	0.65	5.44	6.65	$8.32	9.11	6.69
2028			2.46	0.66	5.48	6.70	$8.38	9.21	6.75

(1) Avoided Firm Capacity Costs are equal to the fixed costs of a SCCT as identified in the Company's 2007 IRP.

(2) A heat rate of 0.727 is used to adjust gas prices from $/MMBtu to ¢/kWh

(3) Estimated avoided cost prices based upon forecast West Side Gas Market Index prices.
Actual prices will be calculated each month using actual index gas prices.

(Continued)

Example of Gas Pricing Options available to the Qualifying Facility
An example of the two gas pricing options using different assumed gas prices is provided at the end of this tariff.

Qualifying Facilities Contracting Procedure

Interconnection and power purchase agreements are handled by different functions within the Company. Interconnection agreements (both transmission and distribution level voltages) are handled by the Company's transmission function (PacifiCorp Transmission Services) while power purchase agreements are handled by the Company's merchant function (PacifiCorp Commercial and Trading).

It is recommended that the owner initiate its request for interconnection 18 months ahead of the anticipated in-service date to allow time for studies, negotiation of agreements, engineering, procurement, and construction of the required interconnection facilities. Early application for interconnection will help ensure that necessary interconnection arrangements proceed in a timely manner on a parallel track with negotiation of the power purchase agreement.

1. Qualifying Facilities up to 10,000 kW

APPLICATION: To owners of existing or proposed QFs with a design capacity less than or equal to 10,000 kW who desire to make sales to the Company in the state of Oregon. Such owners will be required to enter into a written power purchase agreement with the Company pursuant to the procedures set forth below.

I. Process for Completing a Power Purchase Agreement

A. Communications

Unless otherwise directed by the Company, all communications to the Company regarding QF power purchase agreements should be directed in writing as follows:

Pacific Power & Light Company
Manager-QF Contracts
825 NE Multnomah St, Suite 600
Portland, Oregon 97232

The Company will respond to all such communications in a timely manner. If the Company is unable to respond on the basis of incomplete or missing information from the QF owner, the Company shall indicate what additional information is required. Thereafter, the Company will respond in a timely manner following receipt of all required information.

B. Procedures

1. The Company's approved generic or standard form power purchase agreements may be obtained from the Company's website at www.pacificorp.com, or if the owner is unable to obtain it from the website, the Company will send a copy within seven days of a written request.

2. In order to obtain a project specific draft power purchase agreement the owner must provide in writing to the Company, general project information required for the completion of a power purchase agreement, including, but not limited to:

(a) demonstration of ability to obtain QF status;

(Continued)

B. Procedures (Continued)

b) design capacity (MW), station service requirements, and net amount of power to be delivered to the Company's electric system;
c) generation technology and other related technology applicable to the site;
d) proposed site location;
e) schedule of monthly power deliveries;
f) calculation or determination of minimum and maximum annual deliveries;
g) motive force or fuel plan;
h) proposed on-line date and other significant dates required to complete the milestones;
i) proposed contract term and pricing provisions (i.e.,fixed, deadband, gas indexed);
j) status of interconnection or transmission arrangements;
k) point of delivery or interconnection;

3. The Company shall provide a draft power purchase agreement when all information described in Paragraph 2 above has been received in writing from the QF owner. Within 15 business days following receipt of all information required in Paragraph 2, the Company will provide the owner with a draft power purchase agreement including current standard avoided cost prices and/or other optional pricing mechanisms as approved by the Oregon Public Utilities Commission in this Schedule 37.

4. If the owner desires to proceed with the power purchase agreement after reviewing the Company's draft power purchase agreement, it may request in writing that the Company prepare a final draft power purchase agreement. In connection with such request, the owner 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 power purchase agreement. Within 15 business days following receipt of all information requested by the Company in this paragraph 4, the Company will provide the owner with a final draft power purchase agreement.

5 After reviewing the final draft power purchase agreement, the owner may either prepare another set of written comments and proposals or approve the final draft power purchase agreement. If the owner prepares written comments and proposals the Company will respond in 15 business days to those comments and proposals.

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

(Continued)

II. Process for Negotiating Interconnection Agreements

[NOTE: Section II applies only to QFs connecting directly to PacifiCorp's electrical system. An off-system QF should contact its local utility or transmission provider to determine the interconnection requirements and wheeling arrangement necessary to move the power to PacifiCorp's system.]

In addition to negotiating a power purchase agreement, QFs intending to make sales to the Company are also required to enter into an interconnection agreement that governs the physical interconnection of the project to the Company's transmission or distribution system. The Company's obligation to make purchases from a QF is conditioned upon the QF completing all necessary interconnection arrangements. It is recommended that the owner initiate its request for interconnection 18 months ahead of the anticipated in-service date to help ensure that necessary interconnection arrangements proceed in a timely manner on a parallel track with negotiation of the power purchase agreement.

Because of functional separation requirements mandated by the Federal Energy Regulatory Commission, interconnection and power purchase agreements are handled by different functions within the Company. Interconnection agreements (both transmission and distribution level voltages) are handled by the Company's transmission function (including but not limited to PacifiCorp Transmission Services) while power purchase agreements are handled by the Company's merchant function (including but not limited to PacifiCorp's Commercial and Trading Group).

A. Communications

Initial communications regarding interconnection agreements should be directed to the Company in writing as follows:

PacifiCorp
Director - Transmission Services
825 NE Multnomah St, Suite 1600
Portland, Oregon 97232

Based on the project size and other characteristics, the Company will direct the QF owner to the appropriate individual within the Company's transmission function who will be responsible for negotiating the interconnection agreement with the QF owner. Thereafter, the QF owner should direct all communications regarding interconnection agreements to the designated individual, with a copy of any written communications to the address set forth above.

B. Procedures

Generally, the interconnection process involves (1) initiating a request for interconnection, (2) undertaking studies to determine the system impacts associated with the interconnection and the design, cost, and schedules for constructing any necessary interconnection facilities, and (3) executing an interconnection agreement to address facility construction, testing, acceptance, ownership, operation and maintenance issues. Consistent with PURPA and Oregon Public Utility Commission regulations, the owner is responsible for all interconnection costs assessed by the Company on a nondiscriminatory basis. For interconnections impacting the Company's Transmission and Distribution System, the Company will process the interconnection application through PacifiCorp Transmission Services.

(Continued)

Example of Gas Pricing Options given Assumed Gas Prices ¢/kWh

Banded Gas Market Index

Year	Prices Listed in the Tariff				Example using assumed Gas Prices						Compared to Fixed Prices	
	On-Peak Capacity Adder	Off-Peak Energy Adder	Gas Market Index Floor 90%	Gas Market Index Ceiling 110%	Assumed Gas Price $/MMBtu	Actual Energy Price	Fuel Index Floor / Ceiling Component	Fuel Index Type of Price	Price Paid to QF Off-Peak Price	Price Paid to QF On-Peak Price	Off-Peak Price	On-Peak Price
	(a)	(b)	(c)	(d)	(e)	(f) (e)x0.727	(g)	(h)	(i) (b)+(g)	(j) (e)+(f)	(k)	(l)
2012	1.82	0.50	4.82	5.89	$5.00	3.64	4.82	Floor	5.32	7.14	5.86	7.68
					$6.00	4.36	4.82	Floor	5.32	7.14		
					$7.00	5.09	5.09	Actual	5.59	7.41		
					$10.00	7.27	5.89	Ceiling	6.39	8.21		
					$12.00	8.72	5.89	Ceiling	6.39	8.21		

Gas Market Method

Year	Prices Listed in the Tariff				Example using assumed Gas Prices						Compared to Fixed Prices	
	On-Peak Capacity Adder	Off-Peak Energy Adder	Fuel Index Floor 90%	Fuel Index Ceiling 110%	Assumed Gas Price $/MMBtu	Actual Energy Price	Fuel Index Floor / Ceiling Component	Fuel Index Type of Price	Price Paid to QF Off-Peak Price	Price Paid to QF On-Peak Price	Off-Peak Price	On-Peak Price
	(a)	(b)	(c)	(d)	(e)	(f) (e)x0.727	(g)	(h)	(i) (b)+(f)	(j) (e)+(f)	(k)	(l)
2012	1.82	0.50	Not Relevant		$5.00	3.64	Not Relevant		4.14	5.96	5.86	7.72
					$6.00	4.36			4.86	6.68		
					$7.00	5.09			5.59	7.41		
					$10.00	7.27			7.77	9.59		
					$12.00	8.72			9.22	11.04		

Appendix VI

Oregon RPS

OREGON DEPARTMENT OF ENERGY

Summary of Oregon's Renewable Portfolio Standard

The Renewable Portfolio Standard (RPS) requires that all utilities and electricity service suppliers (ESSs)[1] serving Oregon load must include in their portfolio of power sold to retail customers a percentage of electricity generated from qualifying renewable energy sources. The percentage of qualifying electricity that must be included varies over time, with all utilities and ESSs obligated to include some renewably-generated electricity in their portfolio by the year 2025.

Table 1 below summarizes the percentage targets for those affected by the RPS. Note that there are two conditions when utilities have to meet the large utility standard regardless of their size.

Table 1: Summary of RPS Targets and Timelines

RPS obligations on all utilities and electricity service suppliers						
The RPS applies to	**Percent of Oregon's Total Retail Electric Sales**	**Affected Utilities[2] (and ESSs)**	**Applicable Targets in Year[3]:**			
			2011	**2015**	**2020**	**2025**
Large Utilities	Three percent or more	Portland General Electric, PacifiCorp, Eugene Water & Electric Board	**5%**	**15%**	**20%**	**25%**
Smaller Utilities	At least one and a half percent but less than three percent	Central Lincoln PUD, Idaho Power, McMinnville W& L, Clatskanie PUD, Springfield Utility Board, Umatilla Electric Cooperative	**No Interim Targets**			**10%**
Smallest Utilities	Below one and a half percent	All other utilities (31 consumer-owned utilities)				**5%**
Electricity Service Suppliers (ESSs)	Any sales in Oregon	Any Electricity Service Supplier (ESS)	An aggregate target for the ESS is determined by assuming each of the ESS's customers is instead being served by the utility that would otherwise be serving the customer.			
Conditional RPS Targets						
Utilities that Buy New Coal Plants or Power	Below three percent	A utility that buys into a new coal plant or signs a new contract specifically for new coal power is treated as a large utility.	**5%**	**15%**	**20%**	**25%**
Publicly Owned Utilities that Annex	Below three percent	Annexing investor-owned utility territory without consent will trigger being treated as a large utility.	**5%**	**15%**	**20%**	**25%**

[1] Oregon's deregulation law allows non-utility power sellers (called ESSs) to sell power to non-residential customers. Currently, this applies only to Portland General Electric and PacifiCorp service territory.
[2] Based on 2005 Oregon Public Utility Commission (OPUC) utility data (the latest currently available).
[3] Utilities that grow into the 3 percent level have a delayed timeline as if they had entered the RPS initially.

Exemptions and Modifications to RPS Targets

Utilities don't have to comply with an RPS target to the extent that the requirements of the RPS:

- Lead to a utility expending more than four (4) percent of their electricity-related annual revenue requirements on the costs of complying with the RPS.[4]
- Unavoidably displace firm Federal Base System (FBS) preference power rights ("cheap hydro") from the Bonneville Power Administration (BPA) for a consumer-owned utility.
- Result in a utility having no other choice but to acquire power resources in excess of their load requirements in a given compliance year.
- Result in the unavoidable displacement of a non fossil-fueled power resource.
- Unavoidably displace low-price hydropower from power contracts with Mid-Columbia River dams until such a time when those contracts can't be renewed or replaced.

Eligible Resources and Facility Eligibility Date

Qualifying electricity for Oregon's RPS must be derived from the sources and types of facilities listed in Table 2 below. Note that where multiple fuels are used to power a generating facility only the proportion of output that uses qualifying resources can count toward the RPS.

Table 2: Eligible Resource Types Based on Facility Operational Date

<table>
<tr><th>From Generating Facilities in Operation Before January 1, 1995</th><th>From Generating Facilities That Became Operational On or After January 1, 1995</th></tr>
<tr><td rowspan="5">Up to 50 average megawatts per utility, per compliance year, of hydropower owned by an Oregon utility and certified as a low-impact facility by a national certifying entity recognized by ODOE[5] through rulemaking.</td><td>Hydropower, if located outside of certain state, federal, or NW Power & Conservation Council protected water areas.</td></tr>
<tr><td>Wind</td></tr>
<tr><td>Solar Photovoltaic and Solar Thermal</td></tr>
<tr><td>Wave, Tidal, and Ocean Thermal</td></tr>
<tr><td>Geothermal</td></tr>
<tr><td>The increment of improvement from efficiency upgrades made to hydropower facilities, although if the improvement is to a federally-owned BPA dam only Oregon's allocated share of the dam's power output can qualify.</td><td>Biomass and biomass byproducts; including but not limited to organic waste, spent pulping liquor, woody debris or hardwoods as defined by harvesting criteria, agricultural wastes, dedicated energy crops and biogas from digesters, organic matter, wastewater, or municipal solid waste (e.g., landfill gas). However, the burning of trash (municipal solid waste) or wood that is treated with chemical preservatives disqualifies that resource.</td></tr>
<tr><td>The increment of improvement from capacity or efficiency upgrades made to facilities other than hydropower facilities.</td><td>Other resources as determined to qualify through ODOE rulemaking. However, nuclear fission and fossil fuel sources are prohibited in all cases as qualifying resources.</td></tr>
<tr><td colspan="2">Electricity from hydrogen derived from any of the above resources qualifies for the RPS.</td></tr>
</table>

Electricity from BPA that is designated as environmentally-preferred power (or any future BPA product that serves as their renewable energy power choice) qualifies regardless of its source.

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[4] More detail on the cost limitation provisions of the RPS is provided on page 4 of this summary.

[5] ODOE = Oregon Department of Energy OPUC = Oregon Public Utility Commission

Renewable Energy Certificates

Compliance with the RPS requires proof of generation of the qualifying electricity. Like many states, Oregon requires proof that comes in the form of a Renewable Energy Certificate (REC). Each REC represents one megawatt-hour (MWh) of generation of qualifying electricity.

Oregon recognizes two types of Renewable Energy Certificates (RECs) in the RPS. Initially, all RECs are "bundled" together with their associated electricity that is produced at the renewable electricity generation facility. When both a REC and the electricity associated with that REC are acquired together, it is said that one has acquired a bundled REC. Bundled REC ⇗ REC + Power

The owner of a REC may decide to "unbundle" the REC and the electricity associated with that REC and sell each of the two components separately. In doing so the purchaser of the power loses the ability to claim that the power is renewable energy. The REC with no power, however, may be used by its new owner to comply with the RPS. Unbundled REC ⇗ REC with no power

There are different geographic eligibility requirements for different types of RECs in the RPS. Unbundled RECs may come from facilities throughout the entire Western Electricity Coordinating Council (WECC) region -- including British Columbia, Alberta, and a small part of Mexico -- as shown in Figure 1 to the right. In contrast, bundled RECs must come from facilities located in the United States portion of the WECC, as shown in Figure 2 below.

Figure 1: Geographic Eligibility for Unbundled RECs

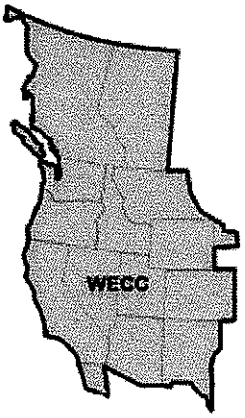
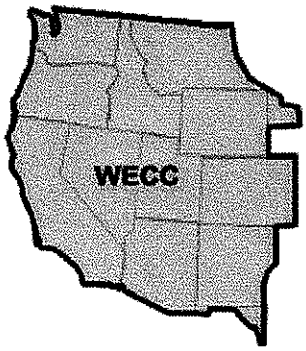


Figure 2: Geographic Eligibility for Bundled RECs



The electricity associated with a bundled REC must also be delivered to the utility or ESS. However, the associated renewable electricity can be "swapped out" for non-qualifying electricity (e.g., from natural gas or coal) as it makes its way to its final destination. This allows for non-qualifying electricity to "shape" or "firm" wind power and other intermittent power resources.

Renewable electricity sold as a product from the Bonneville Power Administration does not have geographic restrictions.

Meeting the Renewable Portfolio Standard with RECs

To meet an RPS target obligated utilities or ESSs must acquire the requisite number of RECs and then retire those RECs permanently. However, for the three largest utilities (only) no more than 20 percent of their compliance in a given year may be met through the use of unbundled RECs, although large consumer-owned utilities (namely EWEB) have a limit of 50 percent until 2020. RECs from PURPA[6] facilities (normally small-scale) in Oregon are exempt from this limit. The same is true for RECs from net-metered, off-grid, or other customer-sited installations in Oregon.

Excess RECs acquired may be banked and used in future years, but older RECs must be used before newer RECs. RECs may also be acquired to "true up" compliance by buying RECs up to 3 months past the end of the year and applying them for compliance with the previous year.

[6] PURPA is a federal law that requires utilities to purchase the output of smaller energy projects.

Consumer Protection and Cost Controls

There are two mechanisms that serve as cost protections for Oregon consumers, an alternative compliance payment mechanism and an overarching "cost cap" on utility RPS expenditures.

Alternative Compliance Payment: In lieu of acquiring a REC to comply with a portion of the RPS, a utility or ESS may instead pay a set amount of money per megawatt-hour (MWh) into a special fund that can be used only for acquiring renewable energy resources in the future, or for energy efficiency and conservation programs. This rate is set for each utility and ESS by the Public Utility Commission or, for consumer-owned utilities, by those utility's governing boards. This mechanism sets an effective cap on the cost of complying with the RPS on a per MWh basis.

Cost Cap: Utilities are not required to comply with the RPS to the extent that the sum of the incremental costs of compliance with the RPS (as compared with fossil-fuel power), the costs of unbundled RECs, and alternative compliance payments made exceed four (4) percent of a utility's annual revenue requirement in a compliance year. RPS compliance costs are not included in the annual revenue requirement to prevent a compounding effect. Consumer-owned utilities may also include R&D costs associated with renewable energy projects in this calculation. An equivalent cost cap for each ESS is determined by rule through the Public Utility Commission.

Resource Diversity

Since an RPS does not, in and of itself, encourage a wide diversity of renewable resources to be developed the state's Public Purpose Charge (PPC) on electric bills is extended through 2025. Moreover, the renewable energy component of the PPC (~ ½ percent) is directed to fund only projects of 20 MW or less. The PPC becomes the complement to the RPS to encourage a balance of project sizes -- especially smaller, community-based renewable energy projects. The RPS also declares the Legislature's desire that, as a non-binding goal, community-based and small-scale projects of 20 MW or less comprise 8 percent of RPS compliance by 2025. In addition, to ensure long-term contract stability for small projects, the state's PURPA law[7] is reinstated for all utilities.

Green Power Programs for All Utilities

As part of the RPS, every utility in Oregon must offer their customers the option of purchasing renewable energy. Because customers are expecting these purchases to go above and beyond what is required of their utility by the RPS, these customer purchases don't count toward the RPS.

Cost Recovery and Compliance Issues for Utilities

Regulated utilities must submit RPS implementation plans but, in general, are subject to the same scrutiny and existing procedural steps. Prudently incurred costs associated with RPS compliance are recoverable in rates, although additional clarity is provided in the RPS as to how these utilities can recover those costs. The RPS allows utilities to recover in the rates of all but the largest customers the costs of conservation measures. Utilities and ESSs must submit annual compliance reports to the OPUC or, in the case of consumer-owned utilities, to their customers or members.

To ensure that People's Utility Districts (PUDs) can comply with the RPS a number of barriers in Oregon law that created issues for their potential compliance are addressed in the RPS.

[7] PURPA was recently repealed in several regions, creating uncertainty for those signing PURPA contracts.

Appendix VII

Net Present Value (NPV)

Net present value (NPV) is the present value of net cash flows. It is a standard method for using the value of money over time to evaluate long-term projects. Used for capital budgets, it converts cash flows, to present value (PV)

Each cash inflow/outflow is discounted back to its present value (PV). Then they are summed. Therefore

$$\mathrm{NPV} = \sum_{t=0}^{N} \frac{C_t}{(1+r)^t}$$

Where

t - the time of the cash flow
N - the total time of the project
r - the discount rate (the rate of return that could be earned on an investment in the financial markets with similar risk.)
C_t - the net cash flow (the amount of cash) at time t (for educational purposes, C_0 is commonly placed to the left of the sum to emphasize its role as the initial investment.).

Typically projects with a positive NPV value could be good investments. That is not to say they should be done. The higher the NPV value the greater the "value" of the opportunity. If more than one project is being considered the one with the higher NPV would be the lesser risk choice, all other assumptions being equal.

In this feasibility study net present value of the investment was calculated based on net revenue from operations, the use of the available tax credits, ad accelerated depreciation. The discount rate was projected at 3.5%.

Appendix VIII

Alternatives

Pellets and 1 MW Power Plant

Pellets can be an independent product line or integrated into a power production facility. The value of wood increases as it is refined and packaged into pellets. Benefits of pellets include improved storage, handling and transport as well as higher energy value by weight and burning efficiency.

Pellet fuel is produced by more than thirty manufacturing facilities in the United States and Canada. These pellet manufacturing facilities receive, sort, grind, dry, compress and bag wood and other biomass products into a convenient pellet fuel. Pellet mills may sell their product directly to customers or market the pellet fuel through retailers. Pellet fuel is typically sold in 40-pound bags, but can also be purchased in bulk quantities. Pellet fuel is a relatively cost stable and price competitive fuel. Current prices for pellets range from $100 per ton to $200 per ton. Using an average cost of $150 per ton of pellets burned in a typical stove, this cost is approximately $11.50 per million Btu's. This compares favorably with the cost of electric heat, and is similar to other common fuel costs in 2007. The Pellet Fuel Institute (PFI) maintains pellet fuel standards.

These include specifications for properties such as bulk density, pellet diameter, pellet length, fines content by weight, chlorides and ash content. The main purpose of these standards is to maintain reliability in pellet fuel products, as organic materials vary widely in their natural properties. Reliable pellet unit performance depends on a fuel supply of consistent quality.

PFI also specifies two grades of fuel: premium and standard. The difference between the two grades is the inorganic ash content which determines how clean it will burn, and subsequently, how much stove maintenance will be required. Premium pellets contain less than one percent inorganic ash content and standard pellets contain less than three percent. Standard grade pellets, which are made of wood waste containing tree bark or coarse agricultural waste such as nut hulls, should only be burned in stoves or furnaces designed to use them. However, 95 percent of available pellets are premium grade, made of hardwood sawdust, and can be used in any pellet stove, furnace or boiler. Pellet production requires a substantial investment. Markets for pellets are increasing with the rising cost of energy and concern over global warming.

Compressed Fire Logs (CFL)

Fire logs require similar front-end drying equipment to that of pellet production. Fire logs can be an additional value added line with a pellet plant. CFLs are easy to light and burn for up to three hours making them a viable alternative to wood logs. Large discount chain stores, smaller chain stores, hardware stores, sporting goods stores, builders supply houses, resorts, retail firewood dealers, mobile home and RV parks and campgrounds are all potential customers.

The Environmental Benefits of using biomass to create pellets or CFLs include:

- Forest fire fuels reduction
- Improved forest management and quality
- Significant reduction of regional imported heating oil annually
- Significant reduction in regional Greenhouse Gas emissions
- Ultra-low carbon footprint in comparison to traditional heating oil

The Competition

Wood pellet manufacturing is not a new industry, with more than 30 facilities already operating in the US and Canada and production of 2,800,000 tons of pellets during the last 12 months (1.6mm tons in Canada and 1.2mm tons in the US). Today, these plants supply two markets:

- residential bagged pellets for home heating (roughly 85%) and the export of industrial-grade
- pellets to Europe for co-firing in coal-fired power plants (currently only from British Columbia).

Two new plants in the Southeastern US will begin delivering pellets to Europe for power generation beginning mid-spring of 2008. Together these plants will add almost 1,000,000 tons of production capacity in the US but provide no new supply to the home or commercial heating markets.

Owing to growing transport costs to move raw materials to a pellet manufacturing plant, and, consequently, trucking costs of delivering the pellets to the customer (retailer or end user), WRCSI believes future competition will likely be limited by geography. Hence, regional manufacturers are focused on the homeowner supply through established retailers already serving the residential market. The pellet manufacturer with the lowest cost/bag and the willingness to meet wholesale terms of large retailers will be successful. As of mid-spring, 2008, there are approximately 30 pellet production facilities in the US and Canada, with annual production capacities ranging from 25,000T to 800,000T. The typical pellet supplier sources its raw materials from adjoining or nearby sawmills. The very large plants (there are two, both in the Southeast) sell only in bulk under long term export contract to European power companies.

Pellet mill costs etc....

According to James Swan, of Clair Michigan, who designs pellet mills, the cost of milling/drying equipment (not counting the building) is typically around $125,000 per ton/hour of production. Meaning a plant with a production capacity of 8 tons per hour would cost in the neighbor hood of $1 million.

A cost Break down is:

Drying Equipment	$550,000
Pellet Mill	$200,000
Other equipment	$200,000
Electrical etc.	$100,000

This does not include log handling, and hogging/chipping equipment, which could add up to $400,000 to the capital requirements.

Mechanical and Electrical operating costs are typically around $35 per ton. Drying costs can be anywhere from $7 to $20 per ton depending upon the fuel source for the dryer (recommended is "slab wood" at $7 per ton). These costs will be offset by the fact that drying and electric will be parasitic.

Labour cost in Wallowa County will be around $15-$25 per ton, depending upon whether the system delivers bulk or bagged pellets.

1 MW with 30,000 tons of pellet production		MW			1.00
LABOR					Operating
Staff necessary to run (24/7 Gasifier plant operations)				Daily	daily
	# of people	Hours	Rate(w/burden)	Cost	Cost
Control room	2	8	22.00	352	
Pellet Manufacturing	5	8	18.00	720	
Repairs/Maintenance	1	8	22.00	176	
Loader Operator	1	8	22.00	176	
Additional PR Burden/Additional Labor				498	
Labor cost				1,922	1,922.40
		1			
OWNERSHIP&OM					
Cost of current size plant /Mwh	1,000,000	1,000,000			
Life expectancy		25.00	Yr		109.59
Generator cost/Mwh	1,500,000	1,500,000			
Life expectancy		25.00	Yr		164.38
Pellet Equipment	1,500,000	1,500,000			
		15.00	Yr		273.97
Log yard Equipment	400,000	400,000			
		15.00	Yr		73.06
Land improvements/concrete/Steel building etc (Total)		250,000			
		35.00	Yr		19.57
Supplies					1,200.00
Parasitic Load and Pellet Manufacturing Costs					1,500.00
MAINTENANCE/SUPPLIES					
Supplies - Monthly		1,000.00			1.39
Repair materials/operating					20.00
Operating - Misc.		-			-
Biomass @ 1 ton/MWH $34/ton to 3 MW, $45 for additional					5,928.00
TOTAL					11,212.36
Revenue @ $.065/KW					
Electricity					1,560.00
Pellets @ $140 per ton					13,440.00
Tipping Fees					-
Net					3,787.64

The above financial model demonstrates that with a significantly lower investment, a pellet manufacturing business could produce income on a par with a large scale power production facility. The model remains positive until pellet pricing goes as low as $110 per ton.

The following NPV analysis further illustrates benefits to this model. An NPV of almost $30 million on an estimated $6 million investment is very, very attractive.

Solution: *NPV of Project is:*					$26,927,288.68		
Year Number **Year 0= NOW** (Year 1= End of first year)	Cash Investment (Cash flow OUT)	Cash Return (Cash flow IN)	"Discount Rate" % assumption for each year **Blank = 0 %**	Calculation aid: reciprocal of discount rate	Cash OUT at discounted value	Cash IN at discounted value	Discounted flow by specific year
Year 0	$6,000,000.00	$2,850,000.00	Not Applicable		$6,000,000	$2,850,000	-$3,150,000
Year 1	$0.00	$2,290,950.00	3.5%	0.966183575	$0	$2,138,626	$2,138,626
Year 2	$0.00	$2,333,128.50	3.5%	0.966183575	$0	$2,254,230	$2,254,230
Year 3	$0.00	$2,376,572.36	3.5%	0.966183575	$0	$2,218,556	$2,218,556
Year 4	$0.00	$2,421,319.53	3.5%	0.966183575	$0	$2,183,891	$2,183,891
Year 5	$0.00	$1,582,409.11	3.5%	0.966183575	$0	$1,378,978	$1,378,978
Year 6	$0.00	$1,629,881.38	3.5%	0.966183575	$0	$1,372,316	$1,372,316
Year 7	$0.00	$1,678,777.83	3.5%	0.966183575	$0	$1,365,687	$1,365,687
Year 8	$0.00	$1,729,141.16	3.5%	0.966183575	$0	$1,359,089	$1,359,089
Year 9	$0.00	$1,781,015.40	3.5%	0.966183575	$0	$1,352,524	$1,352,524
Year 10	$0.00	$1,834,445.86	3.5%	0.966183575	$0	$1,345,990	$1,345,990
Year 11	$0.00	$1,889,479.23	3.5%	0.966183575	$0	$1,339,487	$1,339,487
Year 12	$0.00	$1,946,163.61	3.5%	0.966183575	$0	$1,333,016	$1,333,016
Year 13	$0.00	$2,004,548.52	3.5%	0.966183575	$0	$1,326,577	$1,326,577
Year 14	$0.00	$2,064,684.97	3.5%	0.966183575	$0	$1,320,168	$1,320,168
Year 15	$0.00	$2,126,625.52	3.5%	0.966183575	$0	$1,313,791	$1,313,791
Year 16	$0.00	$2,190,424.29	3.5%	0.966183575	$0	$1,307,444	$1,307,444
Year 17	$0.00	$2,256,137.02	3.5%	0.966183575	$0	$1,301,128	$1,301,128
Year 18	$0.00	$2,323,821.13	3.5%	0.966183575	$0	$1,294,842	$1,294,842
Year 19	$0.00	$2,393,535.76	3.5%	0.966183575	$0	$1,288,587	$1,288,587
Year 20	$0.00	$2,465,341.84	3.5%	0.966183575	$0	$1,282,362	$1,282,362

Profitability/viability will also depend on finding a market for the pellets. The most desirable market would be a local bulk market. Where the pellets are sold as either a replace ment for oil/propane heat, or sold for use in small scale CHP facilities.

Additional Costs could will include pallets and bags, they will add an additional $13 per ton to the cost.

A pellet plants size will be determined by the contractible biomass, and the customer contracts or market potential.

Appendix IX

Public Private Partnerships

PUBLIC-PRIVATE PARTNERSHIPS DEFINED

A Public-Private Partnership is a contractual agreement between a public agency (federal, state or local) and a private sector entity. Through this agreement, the skills and assets of each sector (public and private) are shared in delivering a service or facility for the use of the general public. In addition to the sharing of resources, each party shares in the risks and rewards potential in the delivery of the service and/or facility. These partnerships are often referred to as "PPPs" or P3's.

In some types of PPP, the government uses tax revenue to provide capital for investment, with operations run jointly with the private sector or under contract. In other types (notably the private finance initiative), capital investment is made by the private sector. Government contributions to a PPP may also be in kind (notably the transfer of existing assets).

The formation of partnerships between the public and private sectors is one of the most promising of the newly emerging forms of co-operation that truly goes to the heart of sustainability. Through public-private partnerships, municipal authorities and companies can pool their resources, expertise and approaches to problem solving to tackle challenges in a comprehensive way. Through these partnerships, the advantages of the private sector - dynamism, access to finance, knowledge of technologies, managerial efficiency, entrepreneurial spirit - are combined with the social responsibility, environmental awareness, local knowledge and job generation concerns of the public sectors.

Just as importantly the Public Private Partnership can mitigate the inherent distrust that often exists between the Public and Private sectors. On the one hand the Public Sector often believes the contractor or investor has only commercial goals in mind and the Public Sector will in time fall victim to this. The Private sector on the other hand may believe the Public Sector wishes only to thwart his efforts while minimizing the costs. The result is often a stormy alliance that can be minimized by a well-structured partnership that allows transparency and some common goals.

Even in the best of times, governments at all levels are challenged to keep pace with the demands of their constituencies. During periods of slow growth, government revenues are frequently not sufficient to meet spending demands, necessitating painful spending cuts or tax increases. Partnerships can provide a continued or improved level of service, at reduced costs. Equally important, partnerships can also provide the capital needed for construction of major facilities. By developing partnerships with private-sector entities, governments can maintain quality services despite budget limitations.

The following List is from The *National Council for Public Private Partnerships* website

KEYS TO SUCCESSFUL PUBLIC-PRIVATE PARTNERSHIPS

There are six critical components of any successful Public-Private Partnership (PPP). While there is not a set formula or an absolute foolproof technique in crafting a successful PPP, each of these keys is involved in varying degrees.

POLITICAL LEADERSHIP:
A successful partnership can result only if there is commitment from "the top". The most senior public officials must be willing to be actively involved in supporting the concept of PPPs and taking a leadership role in the development of each given partnership. A well-informed political leader can play a critical role in minimizing misperceptions about the value to the public of an effectively developed partnership. Equally important, there should be a statutory foundation for the implementation of each partnership.

PUBLIC SECTOR INVOLVEMENT:
Once a partnership has been established, the public-sector must remain actively involved in the project or program. On-going monitoring of the performance of the partnership is important in assuring its success. This monitoring should be done on a daily, weekly, monthly or quarterly basis for different aspects of each partnership (the frequency is often defined in the business plan and/or contract).

A WELL THOUGHT-OUT PLAN:
You must know what you expect of the partnership beforehand. A carefully developed plan (often done with the assistance of an outside expert in this field) will substantially increase the probability of success of the partnership. This plan most often will take the form of an extensive, detailed contract, clearly describing the responsibilities of both the public and private partners. In addition to attempting to foresee areas of respective responsibilities, a good plan or contract will include a clearly defined method of dispute resolution (because not all contingencies can be foreseen).

A DEDICATED INCOME STREAM:
While the private partner may provide the initial funding for capital improvements, there must be a means of repayment of this investment over the long term of the partnership. The income stream can be generated by a variety and combination of sources (fees, tolls, shadow tolls, tax increment financing, or a wide range of additional options), but must be assured for the length of the partnership.

COMMUNICATIONS WITH STAKEHOLDERS:
More people will be affected by a partnership than just the public officials and the private-sector partner. Affected employees, the portions of the public receiving the service, the press, appropriate labor unions and relevant interest groups will all have opinions, and frequently significant misconceptions about a partnership and its value to all the public. It is important to communicate openly and candidly with these stakeholders to minimize potential resistance to establishing a partnership.

SELECTING THE RIGHT PARTNER:
The "lowest bid" is not always the best choice for selecting a partner. The "best value" in a partner is critical in a long-term relationship that is central to a successful partnership. A candidate's experience in the specific area of partnerships being considered is an important factor in identifying the right partner. The listing of NCPPP members (provided under Council Members on this site) provides a logical starting point for the identification of potential partners or services that might be required in the development of a partnership.

Disadvantages of PPP's

The most obvious disadvantage to PPP's is that public money/assets are exposed to risk. This risk is real, and the willingness of stakeholders to accept that risk must be assessed prior to beginning a project. This community involvement process can create timeline challenges, and roadblocks that would not be encountered in a private project.

Additionally, given the difficulty in estimating financial outcomes over long periods, there is a risk that the private sector party will either go bankrupt, or make very large profits. Both outcomes can create political problems for the government, causing it to intervene.

When negotiating for feedstock, or other materials used by the project, suppliers may view tough negotiations in a different light if they perceive the project to be about "community benefit" rather than about creating a viable enterprise. It is imperative that the public understand, from project inception, that the business is an independent entity.

Given the length of the relationships created by PPPs and the difficulty in anticipating all contingencies, it is not unusual for aspects of the contracts to be renegotiated at some stage. The contracts are written to take into account as many contingencies as possible, however, given the length of time spanned by the contract, it is almost inevitable that circumstances will arise which cannot be foreseen. It is important that the contract define how it can be renegotiated and it should contain buy/sell provisions that protect both the public and the private investors.

Appendix X

Ash Disposal

Raw wood and wood charcoals normally have an ash content of between 0.75 and 2.5 percent. A high side estimate of 2% would result in ash production of 174 tons per megawatt per year (based on 8700 tons of woody biomass per megawatt of power production).

Uncontaminated ash from woody biomass can be used as a soil amendment. However, if material of unknown origin is introduced into the gasifier, there is a remote possibility that contaminants could be introduced, and ultimately leach into ground water supplies. This means that the feedstock supply must be virgin material if the ash is to be spread on agricultural lands, or extensive testing of the ash must be completed prior to application.

There are several alternative uses for the ash:

Construction materials
The largest potential lies in several kinds of construction material ranging from filler in concrete, to bricks, to post support. Shuangzhen Wang and Larry Baxter from the Department of Chemical Engineering at the Brigham Young University recently presented their "Comprehensive Investigation of Biomass Fly Ash in Concrete" at the Advanced Combustion Engineering Research Center's congress.

They first looked at the strength and microscopy of coal ash concrete, then at the strength and kinetics of concrete with a biomass fly ash filler, and finally at the durability of the material. The analysis looked at five different forms of concrete based on fly-ashes obtained from co-firing coal with respectively switchgrass and saw dust from pure wood, in different ratios.

Their conclusions on biomass fly ash look as follows:

- Equal strength to that of pure cement concrete from 1 month to 1 year after mixing.
- Significant pozzolanic reaction up to one year in concrete.
- 3-6 times the strength of coal ash samples with Ca(OH)2.
- Comparable strength with Ca(OH)2 even to pure cement.
- Quantitative kinetics has been derived
- Matches or outperforms coal ash in reducing ASR expansion

This means that biomass fly ash, in this case derived from pure wood and switchgrass, can potentially be used as a replacement for Portland cement in the production of concrete.

In short, at worst ash from the gasifiers can be used as an additive in concrete, and at best it can replace the cement in concrete. In many areas fly ash is packaged and sold to agricultural producers for use in filling post holes.