

Biopower - overview and context
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1. Overview

Biopower is the extraction of useful energy from biomass as:

- 1) electricity
- 2) heat/steam
- 3) cooling

and can be produced, singly or in combination of two or three of these. Presently most biopower is produced in the pulp and paper and wood products industries. While it is not unusual in industrial settings to produce electricity and heat/steam simultaneously from biomass, it is much less common in the commercial and residential sectors.

According to EIA (DOE/EIA 2006b), in 2005 1.8 quadrillion Btu (quad = 10^{15} Btu) of biomass was consumed in the form of wood and waste, generating electricity and useful thermal output. Of this total, EIA estimates that 0.87 quads were used for electricity generation. In the US, 1.5% of total electricity is generated from wood and waste.

The pulp and paper industry generates more than 50% of its energy needs internally, from black liquor and waste wood. The wood products industry also generates more than 50% of its energy needs internally. Industrial settings are well-suited to utilizing biomass to meet electricity and/or heat/steam needs because generally these loads are relatively steady and the combustion process can be operated at a relatively steady condition. In 2002, the industrial sector utilized 1.56 quads of biomass, of which 0.48 quads were used to generate electricity and 1.08 quads generated useful thermal output (DOE/EIA 2005).

With the exception of biopower produced from black liquor, most electricity biopower production is on a small scale (<50 MW_e, average 20e MW_e) compared to fossil-fuel fired power plants, which can be 100 to 1300 MW_e in a single facility. This is because the production of biomass is dispersed, the energy density of biomass is relatively low, and the moisture content of biomass is often 50% (on a wet basis). For example, the density of wood chips is about 10 dry lb/ft³ and the energy density of wood is around 17,000,000 Btu/dry ton (8500 Btu/ft³), or about 85,000 Btu/ft³. By contrast, coal has an energy density of 25,000,000 Btu/ton and natural gas has an energy density of 1,030,000 Btu/ft³. Most biopower facilities producing electricity are less than 25 MW_e primarily because of transportation costs. It is more economically justifiable to incorporate energy-efficient features in large-scale facilities than small-scale facilities. As a result, most electricity from biomass facilities have a conversion efficiency of around 20% (on a higher heating value basis), whereas coal facilities are more typically in the mid-30% range, and some technologies such as electricity from combined cycle fired with natural gas can be about 50% efficient at converting natural gas into electricity. To justify the more advanced conversion technologies, one has to be at a large enough scale, which in most instances is difficult for biomass to economically achieve, because of biomass transportation costs. However, Bain et al.

(2003) (p. 18) indicate that is changing as efficiency features are being transferred to smaller capacity facilities. Most biomass is trucked to biopower facilities, which limits its economic radius of transport because of its dispersed nature/low density.

For small-scale biopower producers there is also an institutional consideration. A small industrial or commercial facility might pay \$0.08/kWh. If they generate their own electricity, the value of electricity generated is the facility's avoided cost of purchasing electricity from utility of \$0.08/kWh. If they generate more electricity than they need and want to sell their excess electricity generation to the utility, the utility will purchase the power for its avoided cost, which may be in the range of \$0.03/kWh. Therefore, the economic incentive for an industrial or commercial facility to produce electricity is primarily for its own use, rather than to sell to an electric utility.

Natural gas is the most common fuel used to produce heat/steam. Within the past year, the spot market price of natural gas has ranged between \$6 and \$14/million Btu. In much of the 1990s, the spot market price of natural gas was around \$2/million Btu. This increase in natural gas prices creates more incentive for commercial and industrial facilities to use biomass for heat/steam requirements than in the past. Even at \$75/dry ton, biomass is only \$4.50 to \$5/million Btu, which is significantly less than current natural gas prices.

The current market situation for an industrial or commercial facility favors meeting its own heat/steam and possibly cooling needs, and generating electricity up to its own needs. This can be accomplished in a combined heat and power (CHP) facility.

An overview of biopower was published by Research Reports International (2006).

2. Environmental issues related to biopower use

Environmental issues related to feedstock use for biopower (and most conversion technologies) include those related to transport, storage, and the actual process of converting the biomass into electricity, and/or heat/steam, and/or cooling.

Biomass feedstocks may need to be transported from the location they are produced (e.g., a dedicated energy crop from the field to the biopower facility) or they may be used at the site they are produced (e.g., manure from an animal confinement operation used in an on-site anaerobic digester to produce biogas used to cogenerate electricity and heat). Most biomass feedstock transport will occur by truck. Disamenities associated with truck transportation include air quality from truck emissions, loading/unloading and engine noise, and traffic congestion at the biopower facility.

There can be issues related to the transfer of biomass from a truck to storage, truck directly to the biopower facility, or from storage to the biopower facility that can include noise and dust. Possible issues associated with storage include: dust, odor, runoff, volatilization, and fire. With proper design and care, these issues should be manageable.

For the actual conversion process of biomass into biopower, the issues may vary slightly with

regard to each particular conversion process. Air quality issues related to NO_x, SO₂, CO, particulates, and volatile organic compounds (VOC) have to be dealt with, but there are processes and technologies that should keep these pollutants within acceptable levels. Cofiring is becoming more prevalent over time. Both NO_x and SO₂ emissions can be reduced when cofiring: with biomass and coal. Concern with some components of some biomass may reduce the effectiveness of systems for selective catalytic reduction (SCR) of NO_x. Bain et al. (2003) list environmental benefits from 20 biomass projects that burn a variety of biomass fuels to produce electricity (and in some cases cogenerate) that include: burning wood residues under controlled conditions instead of in teepee burners, burning agricultural residues which formerly were burned in fields with no emissions controls, and providing an outlet for nonmerchandise wood, brush, and limbs from forest management operations. Bain et al. (2003) list emissions from existing biomass facilities in California (23 stoker and 11 fluidized beds) that were built before newer, more restrictive emissions standards, the new Pine Tree biomass power plant in Westminster, MA permitted to burn clean construction/demolition wood, and for comparison purposes, natural gas fired systems (Table 1). The Pine Tree facility is a fluidized bed with a low CO and VOC emissions, a mechanical collector and baghouse filter to control particulates, and a selective noncatalytic reduction (SNCR) system for NO_x reduction.

3. Distributed generation.

Distributed generation is typically defined as using small-scale production of electricity at or near the load being served. Distributed generation can come from conventional or renewable technologies, including biomass. Many commercial and industrial customers value highly reliable electricity service, which can be provided by on-site generation, either solely as electricity generation or electricity generation from a CHP operation. Distributed generation is distinguished from traditional electricity generation by: location (at or near the location of use), capacity (small <1 MW_e), and ownership (nonutility). Distributed generation has the potential, if done properly, to:

- a) lower the overall cost of electricity,
- b) enhance the reliability of the power grid,
- c) reduce the need for investment in transmission and distribution to serve growing demand, and
- d) improve environmental quality (CBO 2003).

If not done properly, distributed generation can exacerbate some of these.

Four types of barriers to greater use of distributed generation exist:

- a) contractual and technical interconnection requirements,
- b) surcharges imposed by utilities on operators of distributed generation for standby services,
- c) price of electricity received by distributed generator, and
- d) environmental and permitting requirements of local governments.

CBO (2003) (Chapter 2, Table 1) estimated that in 2000 for industrial and commercial operations, the installed capacity for combined heat and power generation was 49,000 MW and the potential capacity was 163,000 MW. At a heat rate of 5500 Btu/kWh and an 80% load factor, the potential capacity would utilize 6.2 quads of fuel input. If biomass supplied 10% of this potential, approximately 39 million dry tons of biomass per year would be required.

4. Regional perspective

Different regions have differing potential biomass resources available for use and face different prices for competing fuels, such as natural gas and electricity supplied by utilities. Natural gas prices were at an all-time high in 2005, in part because of the aftermath of Hurricane Katrina, averaging in 2005 \$12.84, \$11.59, and \$8.56/thousand ft³ (approximately 1030 Btu/ft³) in the residential, commercial, and industrial sectors, respectively, but vary quite considerably among states, with the highest state price about twice that of the lowest state price (Table 2). As with natural gas prices, there is also considerable variation among state electricity prices, varying in the industrial sector from as low as \$0.04/kWh to as high as \$0.12/kWh, and in the commercial sector from \$0.05/kWh to \$0.16/kWh (Table 3).

5. Benefits of biopower.

Rural development

By its very nature biomass is a dispersed resource, used relatively close to its source. Because it is suitable for distributed generation, opportunities to utilize biopower can occur in many communities. The Southeast has a mix of forest and agricultural feedstocks available, along with a long growing season. These provide the opportunity to utilize fresh feedstocks over the course of the entire year.

With proper planning; communities, commercial and industrial establishments, and even individual residences can take advantage of small-scale use of indigenous resources and generate electricity and heat/steam and even cooling. The use of indigenous resources to generate useful energy allows money to stay within the local community and add to the local tax base. Jobs for harvest, handling, transport, and utilization of biomass are also created and biomass tends to be more labor-intensive than other forms of energy.

On-farm

The on-farm impacts depend on the biomass feedstock under consideration. With crop residues there is a possibility of exacerbating erosion, but this can be mitigated if enough residue is left and depends on tillage practices, and avoiding land that is unsuitable for residue removal. Dedicated perennial energy crops have the potential to reduce erosion and chemical use, if they are replacing annual crops. Use of double cropping can also reduce erosion. Biopower offers an opportunity to utilize manure by collecting it and aerobically digesting the manure to produce biogas to be utilized for electricity and/or heat/steam production. Collection of the manure may reduce runoff from manure spread on fields. There is also the opportunity to utilize riparian buffer strips, which can intercept nutrient and pesticide runoff and the biomass grown can be used for biopower.

Global warming

Biopower offers the opportunity to substitute biomass for fossil fuels. Biomass recycles CO₂. Production of dedicated energy crops and utilization of crop residues typically only use fossil fuels for fertilizers and equipment operation. These typically are a small fraction of the energy in the biomass. There is concern about the N₂O from nitrogen fertilizers. For waste products utilized (e.g., mill residues) the greenhouse gas contribution is quite small.

Energy security

Biopower is produced from local supplies. Petroleum only plays a small role in electricity production (3% of electricity generated and 3% of total petroleum use), while natural gas has increased in importance for electricity production (19% of electricity generated and 27% of natural gas use). Additional natural gas is used in the industrial (35% of natural gas use) and commercial (14% of natural gas use) sectors. Imports of natural gas account for 16% of total consumption and excluding Canada are about 5% of total consumption, but can be expected to increase in the future. Increased use of biopower would have little impact on petroleum security, but could make some impact on natural gas consumption. Domestic natural gas production has been relatively steady since 1995. Biopower can provide commercial and industrial firms with very reliable sources of electricity and heat/steam. Biopower enhances energy security by providing more decentralized power generation.

Farm income and government payments

Biopower can provide an additional market for farm products, allowing some without a market (e.g., manure, crop residues) to be used to produce biopower and either displace purchased energy inputs used on farm or to sell electricity. Increased use of biopower should only have an upside for farm income. In general, crops supported by government payments are not used for biopower. If biopower develops, and some crop land currently used for crops supported by government programs is switched to growing dedicated energy crops, this could cause an increase in crop prices and thus lower government payments.

Other

Others who would benefit from development biopower would be equipment manufacturers, those who manufacture equipment for production and collection of biomass, and those who manufacture the equipment and facilities to convert the biomass into biopower. There would also need to be a whole infrastructure to maintain and operate the conversion facilities.

6. Costs of biopower production

Bain et al. (2003) list a range of costs for cofiring, gasification combined cycle, and direct-fired combustion of biomass. For cofiring, investments are expected to range from \$100-\$700/kW of biomass capacity, with a median of \$180-\$200/kW. For gasification-combined cycle, investment cost is expected to be in the range of \$1400/kW for a mature plant. For direct combustion present capital costs are around \$2000/kW and with the addition of dryers and the incorporation of more-rigorous steam cycles the efficiency will increase to about 30% from the present day 20% for electricity generation, which will lower the capital cost to \$1275/kW. EIA

(DOE/EIA 2006a) lists the cost of a biomass-integrated gasification-combined cycle (IGCC) 80 MW facility at \$1809/kW (2004\$). EIA also lists the cost of a generic baseload distributed generation facility of 2 MW at \$831/kW. Presumably this is based on natural gas as the fuel, and a biomass powered facility would cost more. Table 4 lists capital and operating costs from DOE/EIA (2006a) and Bain et al. (2003).

A report from NREL (Bain 2000) summarizes some preliminary evaluations of a variety of small modular biopower systems. A couple of the systems estimated capital costs listed are around \$1700/kW for a 5 MW and between \$3000 and \$4000/kW for a 1 MW system.

Krich et al. (2005) compiled a report on the production of electricity and methane from dairy waste in California. For a 1000 cow dairy, with NO_x control, with cogeneration, they estimated the cost of electricity at between \$0.062 and \$0.077/kWh, and without cogeneration, at between 0.077 and 0.096/kWh (Table 5). This is equivalent to approximately 100 kW of electrical capacity. Many dairy farms will be smaller than 1000 cows, and costs would go up on a per kWh basis as size decreases.

Lemar and Jones (2004) presented the costs of a number of systems that could be used to generate biopower. They estimate the cost of sealed concrete anaerobic digesters with gas collection and transportation equipment to be in the range of \$900-1500/kW when producing enough fuel for a 30 kW or larger CHP system. Cleaning and maintenance costs are estimated at \$0.001-\$0.003/kWh. Anaerobic digester gas generally does not perform as well as natural gas, being about 10% less efficient in conversion. Fluidized bed gasifier costs are estimated to be in the range of \$600-\$1000/kW with maintenance an additional \$0.001-\$0.003/kWh. When using a high-quality biomass gas, few modifications are required for natural gas combustion turbines, but the lower heat content of the biomass gas makes them 5 to 10% less efficient. Wood-fired boiler-steam turbine systems cost in the range of \$800-\$2000/kW with maintenance costs in the range of \$0.007-\$0.015/kWh. They also estimate costs for reciprocating engines, microturbines, and combustion turbines (Table 6). Equipment costs are slightly higher as are maintenance costs, especially for reciprocating engines. Boiler/steam turbine costs for wood waste in comparison to coal are shown in Table 7.

RETScreen International (2005) offers a computer tool that can analyze costs of biopower production for a number of technologies.

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Table 1. Emissions from biopower compared to coal and natural gas

	lb/MWh				
	NO _x	SO ₂	CO	PM	PM-10
Biomass stoker	2.1	0.08	12.2		0.5
Biomass fluidized bed	0.8	0.08	0.2		0.3
Pine Tree facility, MA (permitted)	0.74	0.78	0.88		0.2
Pulverized coal boiler	6.89	14.3	2.7	0.62	
Fluidized bed-coal	2.7	3.7	9.6	0.30	
Natural gas turbine	1.72	0.009	0.4		0.09
Natural gas combined cycle	0.91 0.21 with SCR	0.004	0.06		0.14

Source: Bain et al. (2003), p. 28, tables 7 and 8.

Table 2. From EIA/DOE (2006b):Table 5.6.B. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State, Year-to-Date through October 2006 and 2005 (Cents per kWh)

Census Division and State	Residential		Commercial ¹		Industrial ¹		All Sectors	
	2006	2005	2006	2005	2006	2005	2006	2005
New England	16.25	13.33	14.7	11.82	10.84	9	14.54	11.83
Connecticut	16.66	13.64	13.71	11.49	11.82	9.39	14.6	12.03
Maine	14.55	13.55	12.35	10.36	8.36	7.14	12.09	10.51
Massachusetts	17.11	13.19	16.08	12.3	11.14	9.13	15.51	12.02
New Hampshire	14.85	13.41	13.9	11.89	12.03	11.15	13.92	12.35
Rhode Island	15.25	12.7	13.72	11.38	12.05	9.74	14.06	11.65
Vermont	13.55	12.95	11.68	11.31	8.36	7.79	11.43	10.94
Middle Atlantic	13.45	12.45	11.94	11.75	7.43	7.27	11.5	11.05
New Jersey	12.96	11.84	11.96	10.66	9.41	9.72	11.98	10.95
New York	16.86	15.48	13.73	14.27	8.67	8.15	14.03	13.82
Pennsylvania	10.46	9.9	8.9	8.48	6.49	6.29	8.65	8.27
East North Central	9.3	8.46	8.27	7.66	5.38	4.91	7.55	6.93
Illinois	8.66	8.47	8.09	7.84	4.71	4.64	7.2	7.03
Indiana	8.27	7.47	7.24	6.51	4.99	4.44	6.49	5.86
Michigan	10.05	8.44	8.74	7.8	6.23	5.32	8.38	7.24
Ohio	9.53	8.59	8.5	7.93	5.52	5.08	7.74	7.09
Wisconsin	10.46	9.65	8.44	7.65	5.89	5.38	8.14	7.46
West North Central	8.24	7.86	6.72	6.38	4.95	4.76	6.73	6.44
Iowa	9.75	9.35	7.44	7	4.97	4.6	7.09	6.75
Kansas	8.37	7.97	7.06	6.62	5.31	4.86	7.02	6.59
Minnesota	8.72	8.31	7.08	6.6	5.23	5.01	6.99	6.63
Missouri	7.62	7.2	6.23	6.03	4.7	4.68	6.46	6.26
Nebraska	7.57	7.28	6.26	6.04	4.57	4.51	6.15	5.97
North Dakota	7.26	7.07	6.36	6.11	4.3	4.38	6.05	5.95
South Dakota	7.97	7.83	6.48	6.2	4.89	5	6.76	6.63
South Atlantic	9.79	8.84	8.38	7.45	5.59	5.27	8.42	7.58
Delaware	11.41	9.03	10.68	7.61	5.09	6.14	9.47	7.75
District of Columbia	10.01	9.15	10.97	9.04	8.96	13.77	10.74	9.12
Florida	11.28	9.58	9.85	8.12	7.65	6.42	10.4	8.73
Georgia	9.17	8.64	7.94	7.58	5.41	5.19	7.79	7.38
Maryland	9.74	8.54	10.12	8.85	10.76	7.01	10.02	8.14
North Carolina	9.11	8.64	7.15	6.82	5.26	5.03	7.54	7.17
South Carolina	9.04	8.64	7.61	7.36	4.74	4.53	6.99	6.7
Virginia	8.54	8.27	6.19	6.03	4.67	4.44	6.87	6.66
West Virginia	6.33	6.23	5.57	5.52	3.69	3.86	5.01	5.16
East South Central	8.18	7.37	7.87	7.1	4.9	4.35	6.83	6.13
Alabama	8.78	7.95	8.14	7.41	4.96	4.47	7.09	6.42
Kentucky	7.12	6.55	6.46	6	4.1	3.67	5.5	5.04
Mississippi	9.56	8.59	9.24	8.24	5.99	5.26	8.31	7.4
Tennessee	7.74	6.92	7.97	7.08	5.36	4.68	7.05	6.24
West South Central	11.49	9.96	9.26	8.31	7.16	6.44	9.5	8.38
Arkansas	8.72	7.96	6.82	6.14	5.3	4.73	6.96	6.3
Louisiana	9.28	8.68	9.03	8.24	7.01	6.37	8.42	7.76
Oklahoma	8.69	7.98	7.5	7.01	5.58	5.09	7.47	6.88

Texas	12.83	10.85	9.83	8.75	7.8	6.97	10.42	9.04
Census Division and State	Residential		Commercial		Industrial		All Sectors	
	2006	2005	2006	2005	2006	2005	2006	2005
Mountain	9.07	8.71	7.6	7.35	5.55	5.45	7.53	7.27
Arizona	9.46	8.99	7.94	7.48	5.85	5.89	8.3	7.9
Colorado	9.14	8.94	7.58	7.45	6.01	5.63	7.73	7.5
Idaho	6.21	6.32	5.19	5.43	3.71	3.96	4.93	5.11
Montana	8.3	8.1	7.48	7.38	4.85	4.73	6.81	6.65
Nevada	11.02	10.08	10.09	9.35	7.98	7.71	9.6	8.97
New Mexico	9.15	9.1	7.7	7.75	5.63	5.5	7.47	7.44
Utah	7.69	7.59	6.24	6.17	4.35	4.36	6.1	6.03
Wyoming	7.8	7.55	6.26	6.2	4.06	4.02	5.27	5.18
Pacific Contiguous	11.67	10.37	11.53	10.58	7.45	7.52	10.7	9.82
California	14.32	12.44	13.32	12.12	9.58	9.65	12.94	11.72
Oregon	7.46	7.22	6.98	6.5	4.46	4.77	6.48	6.3
Washington	6.75	6.52	6.5	6.31	4.36	4.22	6.04	5.83
Pacific Noncontiguous	20.15	17.51	17.22	15.56	16.67	13.94	17.97	15.67
Alaska	14.83	13.15	11.73	11.56	11.77	8.98	12.78	11.59
Hawaii	23.57	20.25	21.65	18.6	18.2	15.4	20.95	17.91
U.S. Total	10.47	9.44	9.42	8.65	6.11	5.71	8.91	8.13

Table 3. Natural gas prices

	Residential		Commercial		Industrial	
	2004	2005	2004	2005	2004	2005
U.S.	10.75	12.84	9.43	11.59	6.53	8.56
Alabama	13.34	15.82	10.91	13.13	7.35	9.51
Alaska	4.88	5.73	4.14	4.93	1.94	2.59
Arizona	12.16	13.54	8.60	9.85	6.91	8.53
Arkansas	11.73	13.65	8.86	10.20	8.03	9.44
California	9.86	11.86	8.63	10.69	7.89	9.84
Colorado	8.47	10.29	7.48	9.39	6.54	8.68
Connecticut	14.06	16.24	11.31	13.00	9.32	11.68
Delaware	12.08	14.58	10.56	12.98	7.72	10.86
District of Columbia	14.31	16.87	13.60	13.17		
Florida	17.75	20.15	11.43	13.28	8.22	9.48
Georgia	13.92	16.77	11.43	14.75	7.53	10.13
Hawaii	27.15	30.94	21.42	25.48	13.22	16.41
Idaho	9.04	10.59	8.37	9.86	6.97	8.39
Illinois	9.41	11.62	9.10	11.20	8.07	10.01
Indiana	9.98	12.11	8.56	11.12	7.99	10.12
Iowa	10.14	12.29	8.51	10.64	7.33	9.46
Kansas	10.73	12.08	10.10	11.45	6.41	7.67
Kentucky	10.97	13.09	10.18	12.27	7.38	9.90
Louisiana	11.20	13.25	9.56	11.43	6.58	9.11
Maine	14.00	16.17	12.30	14.38	10.43	13.74
Maryland	12.39	14.80	9.33	11.97	10.62	12.17
Massachusetts	14.41	15.43	12.48	14.29	12.29	13.67
Michigan	8.52	10.55	7.98	9.40	6.88	8.74
Minnesota	9.50	11.21	8.43	10.16	6.57	8.50
Mississippi	10.56	13.32	8.84	12.04	6.67	9.10
Missouri	11.02	12.67	10.00	11.62	8.80	10.99
Montana	9.19	10.70	9.15	10.72	6.34	8.22
Nebraska	9.06	10.68	7.60	9.45	6.68	8.38
Nevada	10.05	12.46	8.38	10.39	8.57	9.82
New Hampshire	14.52	14.98	13.04	13.69	11.86	12.25
New Jersey	11.59	13.44	10.97	13.10	8.66	11.28
New Mexico	9.57	11.14	7.99	9.31	6.66	8.62
New York	12.50	14.91	10.11	12.88	8.05	9.88
North Carolina	12.70	15.38	10.45	12.93	7.20	11.19
North Dakota	9.03	11.40	8.21	10.33	5.70	9.34
Ohio	10.46	13.00	9.20	11.66	8.84	11.22
Oklahoma	10.22	11.67	9.63	11.01	8.59	9.41
Oregon	11.11	12.90	9.37	10.42	6.30	7.70
Pennsylvania	12.27	14.21	10.60	13.04	8.97	11.30
Rhode Island	13.24	14.79	11.77	13.32	9.63	11.23
South Carolina	12.00	14.84	10.81	13.74	7.69	10.02
South Dakota	9.52	11.68	8.09	10.34	6.26	8.03
Tennessee	10.60	13.50	9.51	12.47	7.44	10.06
Texas	10.37	12.49	8.36	10.48	5.91	7.64
Utah	8.12	9.71	6.75	8.23	5.90	7.33
Vermont	11.03	12.20	8.70	9.69	6.04	7.65

	Residential		Commercial		Industrial	
	2004	2005	2004	2005	2004	2005
Washington	9.91	11.80	9.40	10.43	7.83	10.26
West Virginia	10.91	13.00	10.13	12.22	7.59	10.53
Wisconsin	10.16	11.93	8.71	10.38	7.92	9.91
Wyoming	8.65	10.52	7.24	9.19	6.77	8.26

Source: DOE/EIA (2006c), Natural gas prices

http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_a_EPG0_PRS_DMcf_a.htm

http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_a_EPG0_PCS_DMcf_a.htm

http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_a_EPG0_PIN_DMcf_a.htm

Table 4. Capital costs, efficiency, and electricity and steam output for larger-scale biopower

	Size	Capital cost	Efficiency	Electricity	Steam	Operating cost		Source
Electricity only	MW	2004\$/kW	%	MW _e	1000 lb	\$/kW	¢/kWh	
IGCC	80	1809		80		48.56	0.313	DOE/EIA (2006a)
Combined heat and power		\$2001/kW						
Cofiring	105	156	60	95.7	397		-0.23	Bain et al. (2003)
Direct combustion	75	1747	62	62.2	321		1.73	
Direct combustion	100	1605	62	83.0	428		1.71	
IGCC	75	1991	82	59.3	324		1.14	
IGCC	150	1312	82	118.6	648		0.99	

Table 5. Estimated cost of generating electricity from biogas on a 1000 cow dairy farm

Cost range	Cost (\$/kW)		Cost (\$/kWh)			
	NO _x control	No NO _x control	With cogeneration		Electricity only	
			NO _x control	No NO _x control	NO _x control	No NO _x control
High average	7000	6100	0.077	0.069	0.096	0.086
Low average	5400	4500	0.062	0.054	0.077	0.067

Source: Krich et al. (2005), Table 8-4

Table 6. Equipment, installation, and maintenance costs for reciprocating engines and microturbines

	Natural gas	Anaerobic digester gas/landfill gas	Biomass gas
Reciprocating engines	\$/kW		
Equipment	300-800	350-950	330-880
Installation	200-500	200-500	200-500
	\$/kWh		
Maintenance	0.008-0.027	0.01-0.04	0.01-0.03
Microturbines	\$/kW		
Equipment	700-1300	800-1600	800-1500
Installation	300-700	300-700	300-700
	\$/kWh		
Maintenance	0.006-0.012	0.009-0.018	0.007-0.013
Combustion turbines	\$/kW		
Equipment	300-900	550-1350	330-990
Installation	200-300	200-300	200-300
	\$/kWh		
Maintenance	0.004-0.01	0.007-0.018	0.005-0.012

Source: Lemar and Jones (2004)

Table 7. Equipment, installation, and maintenance costs for boiler/steam turbines

	Coal	Wood waste
	\$/kW	
Equipment	400-1200	500-1500
Installation	200-400	200-400
	\$/kWh	
Maintenance	0.005-0.01	0.008-0.015

Source: Lemar and Jones (2004)