8. Financial Analysis of Biomethane Production

As sources of renewable energy, biogas and biomethane compete in one of two markets: electricity and natural gas (including natural gas vehicle fuels). This chapter provides an overview of these two markets, paying particular attention to how their current structure and pricing might affect the biomethane industry. Factors related to the commercial production and distribution of biomethane are also discussed. The chapter concludes with an evaluation of the estimated costs for building and operating a biogas/biomethane facility and a comparison of these costs to the potential revenue from the sale of the gas.

Biogas and Biomethane as Commercial Products

Dairy biogas has been treated as an unregulated waste product with very little value. As this study has shown, biogas can be used to create at least two renewable energy products, electricity and biomethane, both of which have an economic value. To understand the revenue opportunities that they present, however, we need to understand the existing markets for electricity and natural gas: what do these items cost and what barriers might exist to selling electricity generated from biogas or biomethane into these markets?

Electricity Markets

Electricity is different from all other commodities in that it cannot be stored. Electricity is generated on demand, when it is needed. Thus the capacity of the system is as important as the quantity of electricity that is generated. The electrical load is the flow of electricity required at a specific point in time. Kilowatts are used to measure the system's capacity, while kilowatt-hours indicate the amount of electricity that a system will generate or use in one hour. For example, a 1-kW generator that is running 100% of the time will generate 8,760 kWh in a year.

Baseload electricity is electricity that is generated all the time, such as electricity from a nuclear plant which is very hard to turn on and off. Peaking electricity is generated upon demand during periods when the load is highest. An electricity source whose production matches the demand is a load-following resource. For example, a solar photovoltaic system is a load-following resource because its output increases at the same time that demand for air conditioning is highest. California's peak demand for electricity is driven by summer air conditioning usage.

Despite the restructuring of California's electricity market in 1996 as a result of the passage of AB 1890 (Electric Utility Industry Restructuring Act), California's electricity market remains regulated and strapped by complex rules. California's peak demand for electricity is around 60,000 MW. Even if every dairy in the state generated electricity with biogas from anaerobic digesters, they could produce about 120 MW.

Cost of Electricity

Electricity is priced in kWh or MWh (1 MWh equals 1,000 kWh). Electricity price analysis in California is complex because the retail price includes many components in addition to charges for electricity generation: demand charges, standby charges, transmission and distribution charges, public purpose charges, nuclear decommissioning charges, Department of Water Resources bond servicing, etc. To further complicate matters, a dairy may have many meters, with different tariffs applying to each meter. Often, these are time-of-use tariffs that reflect different charges for different times. For example, the winter base load tariff may be $0.03/kWh, while summer peak may be $0.20/kWh. On average, a dairy spends $0.09 to $0.11/kWh retail for electricity, but this varies depending on the specific utility, the tariff structure that applies to the dairy, and the dairy's time-of-use pattern.

Opportunities and Obstacles for Selling Biogas-Generated Electricity

Dairies that use biogas from anaerobic digesters to generate electricity face market barriers. Under California's current market structure, most dairies cannot sell their electricity. Only if a dairy is large enough to dispatch 1,000 kW, which is very unlikely, can it contract with California's Independent System Operator to sell its electricity.

California's Renewable Portfolio Standard (RPS) provides a potential opportunity for dairies (California SB 1038 of 2002; CEC, 2005) to sell electricity generated from biogas combustion, although there are several problems that must be surmounted. One problem is that bidders must be able to dispatch 1,000 kW, a large amount for one dairy. PG&E has agreed to accept an aggregated bid from more than one dairy if the total meets the 1,000-kW requirement. Pricing is another problem. To meet their target, the California investor-owned utilities (PG&E, Southern California Edison [SCE], and San Diego Gas and Electric [SDG&E]) accept bids and buy the "least cost, best fit" product. Utilities are required only to purchase renewable electricity that is at or below a market price referent that CPUC has determined to be $0.0605/kWh. A small state fund is available to subsidize purchases that are bid at a higher price, but overall, it is uncertain how much benefit, if any, dairy digesters will receive from the RPS in its current form.

Alternatively under PURPA, if a dairy's generator has a *nameplate rating* of less than 100 kW and the local utility is cooperative, the dairy could contract to sell its electricity to the utility. The price it receives will be the utility's *avoided cost*, currently about $0.06/kWh.

A pilot program, legislated under AB 2228, created a limited net metering benefit that could provide some benefits to dairies that generate electricity (see <http://www.energy.ca.gov/-distgen/notices/2002-11-18_forum/AB_2228.PDF>). Although charges for electricity generation can be avoided through this program, most other components of the rate structure such as transmission and distribution, demand charges, public purpose funds, etc. must still be paid. For a typical dairy, these "extra" costs average $0.055 per kWh.[1] Even so, net metering can offer a dairy some financial benefit for those periods when electricity generation exceeds usage. Another useful provision of AB 2228 allows a dairy to aggregate all its meters when crediting exports against imports. (Dairies may have as many as 20 electrical meters.) The net metering legislation does not apply to municipal electrical utilities and the law will expire, under its sunset provision, in January 2006. The dairy industry is supporting AB 728 which will have the law extended and improved.

Besides the limited financial opportunities, dairy digesters face barriers to interconnection. For safety reasons, utilities require distributed generators to obtain an interconnection contract as described under each utility's CPUC-approved Rule 21. First, the dairy must pay a fee for the utility to process the application. If deemed necessary, the utility will undertake an interconnection study and costs for this study must be borne by the applicant. Finally, the utility may require changes to the design of the project; there is no appeal from the utility's decision. Some dairies believe that the utilities are making the interconnection process unnecessarily expensive and difficult.

Changes in the electrical market structure or in any of the provisions discussed above will affect the viability of dairy biogas electrical generation. If net metering currently available under AB 2228 is not renewed by the approval of AB 728, it will have an adverse affect on dairy biogas generators. If someone offers a price for electricity generated from dairy biogas that is above the cost of production (currently about $0.07 to $0.10/kWh), it will encourage more biogas production. In the current market structure, a dairy that can use the electricity it generates on-farm obtains the best financial return because it avoids purchasing electricity at retail cost.

When the retail price of electricity is high, dairies will have more incentive to generate electricity—even if only for their own on-farm use. Rather than reducing commercial biogas production, problems in the electricity market may encourage dairies to use biogas as a feedstock to produce biomethane.

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[1] For specific tariffs see Pacific Gas and Electric Tariff E-BIO, Southern California Edison Tariff BG-NEM, and San Diego Gas and Electric Tariff NEM-BIO.

Natural Gas Markets

California consumes about 6 billion ft^3 of natural gas per day. This gas is burned directly as a fuel, used as a feedstock in manufacturing, or used to generate about one-third of California's electricity (the share used in electricity generation is increasing). Eighty-four percent of the natural gas used in California originates outside the state.

Natural Gas Prices

There are three natural gas prices relevant to this report. The wellhead price is the price at the point of origin of the gas. In the West, this is also called the Henry Hub price. The city-gate price is the price when it is delivered to the distributing gas utility from the natural gas pipeline or transmission facility. It incorporates the wellhead price and transportation to the city gate. The commercial price is the price a commercial customer pays. In this discussion we will reference the small commercial price, because that is the price a dairy would pay for its use.

Most dairies are not on the natural gas grid. If they were most of them would be in PG&E territory and would be charged prices on the small commercial gas tariff. Those prices have varied considerably over the last several years, and are currently at a high price historically, as shown in Table 8-1. The prices shown are for small commercial users; prices for large commercial users are slightly lower.

Table 8-1 Average Price of Natural Gas for PG&E Small Commercial Users, 2000 – 2005

Year	Average Price per 1,000 ft^3 [a] (dollars)
2000	7.62
2001	9.52
2002	6.06
2003	8.49
2004	8.38
2005 [b]	9.84

[a] Price is yearly average based on first 4,000 therms of usage.
[b] Price for 2005 reflects first five months of year only.

Natural gas prices change every month. Summer rates are slightly lower than winter rates, and the rate for the first 4,000 therms of usage is higher than the rate for usage in excess of 4,000 therms. (One therm is 100,000 Btu or approximately 100 ft^3 methane.). Table 8-1 indicates average prices (summer and winter) charged for the first 4,000 therms of usage over the past five years.

Table 8-2 shows current wellhead, city-gate, and small commercial retail distribution prices as well as the six-year high and low price for each category. In May 2005, PG&E's price of natural gas to a small commercial user (such as a dairy), averaged $9.84 per 1,000 ft^3, down from $10.90 in December 2004. As recently as April 2004, the price was $6.94. As shown in Table 8-2, the range of small commercial retail prices in the last five years went from a low of $4.03 in October 2001 to a high of $17.30 in January 2001.

Table 8-2 Natural Gas Wellhead, City-Gate, and Distribution Prices (Current Price and Historical Highs and Lows from 2000 through 2005)

Natural Gas	**Dollars per 1,000 ft^3**		
		Price Range 2000 – 2005	
	Current Price [a]	**Low**	**High**
Wellhead price [b]	$6.05	$2.19	$6.82
City-gate price [b]	$7.44	$3.27	$8.91
Distribution price (small commercial retail) [c]	$9.84	$4.03	$17.30

[a] May 2005

[b] Source: US DOE Energy Information Administration website <http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm >

[c] Source: Pacific Gas and Electric Rate Information website <http://www.pge.com/rates/tariffs/GRF.SHTML#GNR1>

The wellhead price of natural gas is significantly less than the retail price, typically in the range of $5 to $6 per 1,000 ft^3. In December 2004, the wellhead price was $6.25/1,000 ft^3, its highest level since January 2001. In 2004, the average wellhead price was $5.49/1,000 ft^3 (see U.S. Energy Information Administration website <http://tonto.eia.doe.gov/dnav/ng/ng_pri _top.asp>).

Opportunities and Obstacles for Selling Biomethane on the Natural Gas Market

Electrical usage is ubiquitous, but much of California's rural areas are not on the natural gas grid. Whether or not a dairy produces biomethane will depend on its ability to get the biomethane to a profitable market. As discussed in Chapter 5, biomethane can be used for on-farm purposes such as a load-following electrical resource or as a fuel for chillers, heating, pumps, or vehicles. However, converting these items to run on biomethane would be expensive and, on a typical dairy it would not be practical to use more than a fraction of the biomethane generated (if all biogas were upgraded). Thus, in all likelihood, biomethane production will be cost effective only if the biomethane can be sold to an off-dairy customer, either by distributing it through a natural gas pipeline grid, or by transporting it by private pipeline or vehicle to a site where it can be used or sold.

One obstacle to using a utility grid pipeline to transport biomethane is that the biomethane must meet the generally stringent quality standards of the utility (see Chapters 5 and 7). Also, the dairy must secure a contract with the utility. If the biomethane cannot be put it into the grid, either because a natural gas pipeline is not accessible to the dairy, or because of quality or regulatory barriers, then it must be transported over the road or through a dedicate pipeline to a site where it can be used or sold (see Chapters 4 and 7).

Comparison of Natural Gas and Electricity Prices

Natural gas prices are an important component of electrical prices because a third of California's electricity comes from combusting natural gas. At the wholesale level, prices for natural gas and electricity are correlative. At the retail level there is less correlation because of price regulation, hedging, market power, environmental permitting, and a variety of other issues (Bushnell, 2004). Electricity cannot be stored, so prices are very responsive to even small changes in demand, making retail electricity prices far more volatile than natural gas prices.

Electricity and natural gas prices can be compared by evaluating their relative energy content and the amount of natural gas (in ft^3) it takes to produce 1 kWh of electricity. In its raw state (i.e., when it comes out of the ground), natural gas can vary tremendously in methane content, typically ranging from 70 to 90% methane (see Natural Gas Supply Association website at <http://www.naturalgas.org/overview/background.asp>). Before it can be transported and used commercially, natural gas must meet pipeline standards. These standards vary by utility and pipeline (see Table 7-3 in Chapter 7), but commercial or pipeline-quality natural gas is typically 97% methane with small amounts of other light hydrocarbons such as propane and butane. .

Pure methane contains 1 million Btu/1,000 ft^3. To simplify our discussion, we will consider commercial natural gas to have the same Btu content as pure methane. 1 kWh of electricity contains 3,412 Btu (see Appendix E for more information regarding the Btu content and equivalencies of various fuels). Thus, the energy content of 3.4 ft^3 of natural gas is the same as 1 kWh of electricity. Of course there is a major efficiency loss whenever one form of energy is converted into another. In the case of converting natural gas to electricity, gas-fired peaking turbines are 33% efficient, and modern central station base load combined cycle gas turbines are about 50% efficient. Dairy generators are typically 28% efficient. Table 8-3 shows the approximate amount of natural gas (or biomethane) it would take to generate 1 kWh of electricity at these various conversion efficiencies.

Table 8-3 Natural Gas to Electricity Conversion at Various Efficiency Rates

Conversion Efficiency Rate (%)	Btu	Volume of Natural Gas (ft^3) Needed for 1 kWh Electricity
28	12,000	12.0
33	10,400	10.4
50	6,800	6.8
100	3,400	3.4

A utility generator with a conversion efficiency of 50% will require about $0.041 worth of natural gas to produce 1 kWh of electricity. This is, historically, fairly expensive. During the 1990s, for example, when the price of natural gas averaged below $2/1,000 ft^3, the same utility would have spent less than $0.015 on natural gas to generate 1 kWh (see U.S. Energy Information

Administration website at <http://tonto.eia.doe.gov/dnav/ng/ng_pri_top.asp> for historical gas prices).

Estimated Costs for a Dairy Anaerobic Digester Facility

This section presents estimated costs to build an anaerobic digester for electrical generation as well as an anaerobic digester to create biomethane. The estimated cost ranges are meant to be general guidelines, not costs for a specific project.

Basic System Components

A dairy anaerobic digester that will be used to create biogas for electrical generation has two major components. The first is the system to generate and collect the biogas. This can be a covered lagoon, plug-flow, or complete-mix digester system, as described in Chapter 2 (and Appendix B). The second component is the system to generate the electricity. In its simplest form, this may consist only of a generator and control system; more sophisticated systems may include H_2S reduction and NO_x (catalytic) control. Waste heat is usually captured and used to replace natural gas or propane in heating.

A dairy anaerobic digester whose ultimate purpose is to produce biomethane uses the same sort of digester to generate and collect the biogas. The biogas is then upgraded to biomethane by removing the H_2S, moisture, and CO_2 (see Chapter 3). Finally, the biomethane is compressed or liquefied, stored, and/or transported to a location where it can be used.

Cost Range for Dairy Anaerobic Digester and Electrical Generation Facility

For this study, we analyzed the costs for 18 dairy digesters that were reported in the Lusk Casebook (Lusk, 1998) and several other sources (Moser and Mattocks, 2000; Mattocks, 2000; Nelson and Lamb, 2000). For details see Appendix G. The average cost for building the 12 anaerobic digester systems cited in these sources that generated on average more than 50 kilowatts was about $4,500 per average kilowatt generated. In contrast, an analysis of four projects completed under California’s Dairy Power Production Program showed average costs of $6,100 per nameplate kilowatt. Based on these “high” and “low” averages, Table 8-4 provides cost ranges for the various digesters, both with and without equipment to control NO_x emissions. The dairies that applied to the Dairy Power Production Program also indicated on average that the value of the heat they expected to produce was about 20% of the value of the electricity. If co-generation of heat and power were used to offset the cost of electrical generation, the costs per kWh would come down by 20%, as shown in Table 8-4. These costs compare favorably to the dairy’s retail price of electricity, currently $0.09 to $0.11/kWh.

Table 8-4 Estimated Costs of Generating Electricity from Biogas Produced on a Typical 1,000-Cow Dairy [a]

	Cost per Kilowatt ($)		Cost per Kilowatt-Hour ($)			
			With Co-Generation		Without Co-Generation	
Cost Range	NO_x Control	No NO_x Control	NOx Control	No NO_x Control	NO_x Control	No NO_x Control
High average [b]	7,000	6,100	0.077	0.069	0.096	0.086
Low average [c]	5,400	4,500	0.062	0.054	0.077	0.067

a A typical 1,000-cow dairy is assumed to have biogas production of 50 ft^3/cow/day, with 60% methane content; thus, the dairy will produce 30 ft^3/cow/day or 30,000 ft^3/day methane (equivalent to 1,250 ft^3/hour). At an approximate Btu content of 1,000 Btu/ft^3 methane, this is equivalent to about 100 kW of electrical capacity (1 kW equals approximately 3,415 Btu/hour). To convert this to kWh, we must consider the efficiency of the conversion process, which is estimated at 28% for a dairy operation. To produce 1 kWh of electricity at 28% conversion efficiency takes approximately 12.0 ft^3 methane (1 kWh is equivalent to approximately 3.4 ft^3 of methane). Thus, in one day (at a production level of 30,000 ft^3/day), the dairy can produce 2,450 kWh or 2.45 kWh/cow/day.

b Source: Applications submitted to California Dairy Power Production Program

c Source: Lusk, 1998; Moser and Mattocks, 2000; Mattocks, 2000; Nelson and Lamb, 2000; see Appendix G.

Based on the lower costs, the capital costs for a digester-generator with a capacity of about 100-kW would be about $450,000 (without NO_x controls), exclusive of land costs. At a production level of 2,450 kWh/day and operations and maintenance costs of about $0.015/kWh, a facility with a 20-year life and an 8% cost of capital would have a levelized cost of electricity (over 20 years) of $0.067/kWh. If controls for NO_x emissions are added (another $90,000 in capital costs), the levelized cost of electricity goes up to about $0.077 per kWh. The most likely scenario for California is an anaerobic generator with NO_x controls and co-generation, which gives a cost range of $0.062 to $0.077/kWh. For purposes of further analysis in this report, if only one capital cost is given for anaerobic digestion electricity it is a capital cost of $4,500 per average kilowatt for 1,000 and 1,500 cow dairies, and a cost 20% lower (based on an assumption reflecting anticipated economies of scale) is used for 8,000 cow and larger dairies.

Cost Range for Dairy Digester and Biogas Upgrading Facility

Estimating the costs of a digester system for biomethane production is more speculative than for a digester-generator. Although a few biomethane facilities have been built on landfills in the USA, the scale for these is far larger than would be needed for a dairy or even a centralized facility serving a group of dairies. To date, no biogas upgrading facility has been built on a dairy, at least not in the USA.

Several biomethane facilities using animal manure and other types of organic waste as a feedstock have been built in Europe. Sweden is the leader in this type of facility, with 20 plants that produce biomethane. The biogas used for these facilities is generated from organic waste such as manure, slaughterhouse waste, and food processing waste. Other biomethane plants exist in Switzerland, Denmark, and the Netherlands.

Actual Costs of Plants to Upgrade Biogas to Biomethane in Sweden

As part of this project, several of the authors of this report visited Sweden in June 2004 to tour biomethane plants (WestStart-CALSTART, 2004). During our tour, we were able to obtain cost data on four biomethane plants.

The scale of the Swedish biomethane facilities is smaller than the landfill-gas upgrading plants in the USA, but larger than what would be required for most dairy facilities. The Linkoping facility would need 27,000 cows, while the Laholm and Boras facilities would need 7,000 to10,000 cows each. The smallest plant, at Kalmar, could operate with manure from 1,500 to 2,000 cows. Each of these four plants removes H_2S, moisture, and CO_2 from the raw biogas. The resultant biomethane is put into a pipeline, or compressed for storage and/or transportation.

Table 8-5 summarizes the costs from the four Swedish plants. These costs reflect Swedish experience; no doubt U.S. costs would be different, for a variety of reasons. The costs in Table 8-5 also reflect a range of costs; for example, capital costs per 1,000 ft^3 of produced biomethane decline steadily with volume. The lowest volume plant, Kalmar, cost \$2.20/1,000 ft^3 to build. The Linkoping plant was the largest plant; its capital costs were \$0.74/1,000 ft^3.

In each case, operating and maintenance costs exceed capital costs by a significant margin. This contrasts with electricity generation, where the capital costs exceed the operating costs. Table 8-5 shows that operating costs per ft^3 increase with volume, based on the three Swedish examples for which we have data on operating cost or total cost. This is counterintuitive and, more than likely, a random result. Analysis of operating costs at landfill gas plants in the USA revealed a wide range of operating costs that were not correlated with size (Augenstein and Pacey, 1992, p. 17).

Based on the three Swedish examples, for which operating cost data was either available or derived, the cost to produce and compress biomethane from biogas ranged from \$5.48 to \$7.56 per 1,000 ft^3. All three of these plants are larger in scale than a normal dairy upgrading plant would be—approximately 8,000 cows would be required to produce as much biogas as is processed in the smallest of the three (Boras). Neither total costs nor operating costs were available for the Kalmar facility, which is the only one of the four plants comparable in size to any but the largest California dairies

Extrapolation of Actual Costs to Estimated Costs for a Dairy Biogas to Biomethane Plant

To try to project reasonable costs for a small dairy biogas upgrading plant, we used the capital cost of the smallest Swedish plant, Kalmar, which was estimated to be \$500,000. This cost was also cross-checked: QuestAir Technologies, Inc. (<http://www.bctia.org/members /QuestAir_Technologies_Inc.asp>) claims to have a small skid-mounted pressure-swing absorption plant that can remove CO_2 in the needed quantities. This plant retails for about \$300,000. After adding \$50,000 for an H_2S scrubber and \$150,000 for storage, the total cost would be about \$500,000.

Table 8-6 shows the estimated costs for three hypothetical plants: a small dairy biogas upgrading plant and two large dairy biogas upgrading plants which differ in operating costs. The estimated operating cost for the small dairy plant was taken from the average of the three Swedish plants discussed above. Operating costs for “large dairy A” are based on the Boras plant, and “large plant B’s” operating costs are based on the Linkoping plant.

The operating and maintenance cost exceeds the capital costs in all three hypothetical plants. The actual building and operating of a plant in the USA will likely have a different cost than the Swedish plant. It will probably cost more since U.S. contractors will not be as far along the learning curve as Swedish contractors. It may be more expensive to operate and maintain than Swedish plants because of the lack of experience in the USA, though labor rates may be lower. Another difference is that the Swedish plants are centralized facilities that process several different feedstocks.

Estimated Cost of Anaerobic Digester and Biogas to Biomethane Plant

The full cost of producing biomethane at a dairy includes an anaerobic digester that generates and collects the biogas as well as the upgrading facility. Earlier in this chapter we reviewed costs for an anaerobic digester in the context of electrical generation. Table 8-7 shows combined costs for an anaerobic digester and upgrading plant for the same hypothetical plants shown in Table 8-6: a small dairy with a low-cost digester and two large dairies (or centralized facilities), whose operating costs are based on the Boras and Linkoping plants in Sweden.

Estimated Cost of Liquefied Biomethane Plant

A final alternative to consider from a financial aspect is an upgrading plant that produces liquefied biomethane (instead of compressed biomethane) as its final product. As discussed below, the scale of this plant needs to be at least twice as large as the examples shown in Tables 8-6 and 8-7.

We saw in Chapter 4 that LBM cannot be stored economically for more than a few days because the product will begin to evaporate as temperatures rise. If LBM production is sufficient to fill a 10,000-gallon cryogenic tanker truck every few days cost effectively, LBM may prove to have a better market than CBM in California (currently almost all of the LNG used in California is trucked in from out of state).

Table 8-5 Operating Parameters and Associated Costs for Four Swedish Biogas-to-Biomethane Plants

Facility Name	Methane Output [a]		Capital Costs ($) [b]			Operation & Maintenance ($ per 1,000 ft³)	Total Costs ($ per 1,000 ft³)
	ft³/hr	ft³/d	Total	Annual Amortization (8% for 20 years)	Costs per 1,000 ft³		
Linkoping [c]	33,606	807,000	2,133,333	217,285	0.74	6.82	7.56
Laholm [d]	12,355	297,000	1,200,000	122,223	1.13	4.53	5.66
Boras [e]	9,884	237,000	1,500,000	152,778	1.77	3.71	5.48
Kalmar [f]	2,648	64,000	500,000	50,296	2.20	---	---

[a] Methane production for all plants given in cubic meters (m^3) and converted to cubic feet (ft^3) (35.3 ft^3 / m^3).

[b] Costs for all plants given in Swedish Kroners and converted to US dollars (7.5 SK /$).

[c] Figures provided for Linkoping included biogas input (1,360 m^3/hr), total costs (2 SEK/m^3) and capital costs (16,000,000 SEK); all other figures derived.

[d] Figures provided for Laholm included methane output (350 m^3/hr), capital costs (9,000,000 SEK), and operating costs (1.2 SEK/m^3); all other figures derived.

[e] Figures provided for Boras included methane output (280 m^3/hr) and capital costs as shown ($1,500,000), and total costs (1.45 SEK/m^3); all other figures derived.

[f] Figures provided for Kalmar included methane output (75 m^3/hr) and capital costs as shown ($500,000)); all other figures derived, where possible.

Table 8-6 Estimated Costs for Three Hypothetical Dairy Biogas-to-Biomethane Plants

Facility	No. Cows or Cow-Equivalents [a]	Methane ft³/d	Estimated Capital Costs ($)			Estimated Operation & Maintenance ($ per 1,000 ft³)	Estimated Total Costs ($/1,000 ft³)
			Total	Annual Amortization (8% for 20 years)	per 1,000 ft³ Biomethane		
Small dairy plant [b]	1,500	45,000	500,000	50,926	3.10	5.02	8.12
Large dairy A [c]	8,000	240,000	1,500,000	152,778	1.74	3.71	5.46
Large dairy B [d]	8,000	240,000	1,500,000	152,778	1.74	6.82	8.56

[a] Based on an approximate figure of 30 ft^3/cow/day of methane.

[b] Operating costs based on average of three Swedish plants; capital costs based on Kalmar plant.

[c] Operating and capital costs based on Boras plant in Sweden.

[d] Operating cost based on Linkoping plant in Sweden; capital costs based on Boras plant.

Table 8-7 Estimated Costs for Three Hypothetical Dairy Anaerobic Digester and Biogas to Biomethane Plant

Facility	Number of Cows or Cow-Equivalents	Methane [a] ft^3/d	Dollars per 1,000 ft^3 Biomethane				
			Estimated Cost for Anaerobic Digester ($ per 1,000 ft^3)		Estimated Cost for Biogas Upgrading ($ per 1,000 ft^3)		Estimated Total Cost ($/1,000 ft^3)
			Capital	Operation & Maintenance	Capital	Operation & Maintenance	
Small dairy plant [b]	1,500	45,000	3.10	0.60	3.10	5.02	11.82
Large dairy A [c]	8,000	240,000	2.48	0.50	1.74	3.71	8.44
Large dairy B [d]	8,000	240,000	2.48	0.50	1.74	6.82	11.54

[a] Based on an approximate figure of 30 ft^3/cow/day of methane.

[b] Operating costs based on average of three Swedish plants; capital costs based on Kalmar plant.

[c] Operating costs and capital based on Boras plant in Sweden.

[d] Operating cost based on Linkoping plant in Sweden; capital costs based on Boras plant.

According to Acrion Systems, for $1 million it is possible to build a LBM plant capable of processing 200,000 ft^3 of biogas daily to generate 860 diesel gallon equivalents (DGE) of LBM. The plant would need 300 kW of electrical generation. To operate, it will also need all three components discussed above: an anaerobic digester, a generator to create electricity from a bit less than half of the biogas, and a plant to upgrade and liquefy the remaining biogas to produce LBM. However, a facility of this size would only produce enough LBM to fill a 10,000-gallon LNG tanker truck every seven days. To minimize thermal losses and keep the operation economical, the LBM should not be stored for this length of time. Therefore, we chose to examine costs for a plant twice this size (i.e., one that can produce about 1,714 DGE of LBM each day). As a comparison to the earlier plants we considered, this facility would need to digest waste from 13,760 cows.

Input requirements, expected output, and costs for such a facility are shown in Table 8-8. The facility would use part of the biogas produced in its digester to generate electricity to run the LBM plant; the remainder of the biogas would be feedstock for the biogas upgrading plant. The entire cost of the anaerobic digester is applied to the cubic feet of biomethane incorporated into the LBM produced, since the remainder of the biogas is an intermediate product used to generate electricity needed in liquefaction. Thus, the operating cost of the anaerobic digester per 1,000 cubic feet of methane is higher than the costs shown in Tables 8-6 and 8-7. The operating costs of electrical generation are also applied only to the LBM produced.

An 8,000-cow dairy could produce the same amount of liquefied biomethane, but would have to purchase 300 kW of electricity. Since costs for generating electricity from anaerobic digestion should be less than costs for purchased electricity, the smaller (8,000-cow) dairy would have higher production costs.

For comparison, the current fleet pump price for LNG as a vehicle fuel is about $1.00 per LNG gallon or $1.67 per DGE (NexGen Fueling, personal communication, 28 March 2005). Fleets with long-term contracts may pay much less. Of that $1.00, Federal excise tax is about 12 cents, state excise tax is 6 cents, and state and local sales tax is about 8 cents. Thus, the price of LNG before tax is about $0.74 per gallon, or about $1.23 per DGE. This price reflects the cost of transporting the fuel to the fueling station as well as built-in cost recovery and profit for the fueling station; but neither these costs nor taxes are shown in Table 8-8.

Table 8-8 Estimated Inputs, Outputs and Associated Costs for Large Dairy Digester, Generator, and Liquefied Biomethane Facility

Input Requirements		***Estimated Component Costs ($)***	
Number of Cows	13,760	Anaerobic digester	5,160,000
Cows for electricity	5,760	Generator	540,000
Cows for LBM	8,000	Upgrading plant to LBM	2,000,000
Biogas production (ft^3/day)	688,000	Total capital cost	7,700,000
Biogas for electricity	288,000		
Biogas used for biomethane feedstock	400,000		
Electrical capacity (kW)	600		
Facility Output		***Estimated Costs to Produce LBM ($)***	
Biomethane ft^3/day (feedstock for LBM)	240,000	Capital cost per yr, amortized at 8% over 20 years	785,262.00
LBM output gal/day [a]	2,857	Capital cost / 1,000 ft^3 biomethane	8.595
LBM output in DGE/day [b]	1,714	Digester O&M / 1,000 ft^3 biomethane	1.43
[a] 1 gal of LBM = 84 ft^3 methane [b] 1 DGE of LBM = 140 ft^3 methane		Generator O&M / 1,000 ft^3 biomethane	0.90
		LBM upgrade plant O&M / 1,000 ft^3 biomethane	3.71
		Total cost for producing LBM (per 1,000 ft^3 biomethane)	15.00
		Total cost per DGE of LBM	2.10
		Total cost per gallon of LBM	1.26

Estimated Cost to Store and Transport Biomethane

The cost of producing biogas and upgrading it to biomethane reflect only a part, albeit a substantial one, of the actual costs incurred by the producer. In addition, the producer needs to consider the costs of storing and transporting the biomethane, in whatever format required by the end market. Even if a dairy converted all of its on-farm equipment to run on biomethane (an unlikely scenario), and used only part of its digester biogas as a feedstock for producing biomethane, it could prove necessary to store more than one day's production of biomethane.

Small scale storage can be expensive. For example, a Volvo Bus roof-mounted 1,025-liter, 200-bar CNG storage tank costs $25,000. When translated to normal gas processing units this is approximately equivalent to $3.50/scf of stored gas. Storage tanks for CNG, which can also be used to store biomethane, have a typical capacity of 1,000 ft^3 and cost $2,250 to $5,000 each. Capital costs for storage vary considerably with the length of time for which the gas must be stored. Each day's storage will add to the capital cost. For example, enough storage capacity to store a day's worth of CBM produced from a 45,000-ft^3/day plant would add $100,000 to $225,000 to the cost of the facility or $0.60 to $1.40 per 1,000 ft^3 to the cost of the biomethane production. Two days' worth of storage would double those numbers.

Transportation of biomethane incurs additional costs. Typically, biomethane produced on-farm would need to be transported to a location where it could be used or further distributed, such as an industrial plant or a CNG fueling station. Thus, the costs of trucking the biomethane or pumping it through a dedicated pipeline would need to be added to its production price.

The only way a dairy biomethane producer could avoid incurring the costs of storage and transportation for off-farm use of the biomethane would be to place the biomethane directly into a distribution line connected to the natural gas pipeline grid. Access to a natural gas pipeline is subject to the same kind of regulation and interconnection issues that face distributed electricity generators (see discussion earlier in this chapter). Obtaining contracts to place biomethane in the natural gas grid would take a pioneering effort. In addition, most dairies are not serviced by a natural gas pipeline, which means they have no immediate physical access. However, if obstacles such as these could be overcome, direct placement of biomethane into the natural gas pipeline grid would be the most cost-effective way of getting the gas to market. The down side is that the biomethane would have to compete with city gate or industrial prices for natural gas rather than small commercial retail prices.

The only other option for distribution of biomethane to off-farm markets is to privately pipe or truck the gas to an industrial user or a CNG or LNG fueling station. Both of these alternatives are expensive. A dedicated pipeline system that served the Boras plant in Sweden was just over 4 miles long and cost $213,000 per mile. Costs could be reduced by using horizontal trenching. In Sweden horizontally trenched pipelines were built for 500 SEK per meter, or about $100,000 per mile. Estimates for U.S. piping costs vary from $100,000 to $250,000 per mile depending on the number of landowners involved, the need to cross public rights-of-way, the terrain, and similar factors (Rachel Goldstein, US EPA Landfill Gas Program, personal communication with Ken Krich, 1 March 2005). Piping eliminates the need for on-site storage, though there is still a need for storage at the point of usage.

As with the storage costs, transportation adds to the capital cost of the plant. Transportation costs will depend on the distance that the gas needs to be moved. Trucking requires more on-site storage than piping because enough biomethane must be accumulated to fill a tanker. Typically, trucking would occur on a cyclical basis; alternatively enough additional trucks could be purchased or made available so that one truck is always available on-site for filling, thus eliminating the need for other on-site storage. However, trucks also have associated capital costs, as well as operating costs such as fuel and maintenance for the truck, and labor costs for the driver. Other than for LBM, transportation of biomethane by truck costs more per volume than pipeline transport and should only be considered as an interim solution.

Cost Summary: Range of Estimated Costs for Digester and Biomethane Plant

Based on costs for similar (albeit larger) plants in Sweden, as well as on discussions with equipment suppliers and others, our best estimates for the various capital and operating costs associated with a dairy digester and biogas upgrading plant are shown in Table 8-9.

Table 8-9 Estimated Range of Costs for Dairy Digester and Biogas to Biomethane Plant

Component or Process	Dollars per 1,000 ft^3	
	Low Estimate Large Dairy	**High Estimate Small Dairy**
Anaerobic digester		
Capital cost	2.50	4.65
Operating cost	0.50	0.60
Biomethane (Upgrading) Plant		
Capital cost	1.55	3.10
Operating cost	3.70	6.80
Biomethane storage	0.00	2.80
Biomethane transport	0.00	0.90

One day’s storage cost is included in the biomethane plant capital cost shown in Table 8-9. The extra storage costs depend on the number of days of additional storage required. If the biomethane were sold to a gas utility and entered the natural gas pipeline grid, or if it were transported off the dairy every day, the storage cost would be zero. The high range shown assumes that the plant’s total storage is three days’ production.

Transportation costs depend on the distance the biomethane needs to be transported. If the biomethane is sold to a gas utility and enters the natural gas pipeline grid, transportation costs are zero. The high number assumes an 8,000-cow dairy that will transport biomethane 5 miles by a dedicated pipeline, which was built at a cost of $150,000 per mile.

Summary of Financial Challenges to Building a Biomethane Plant

Like other pioneering renewable energy technologies, the production and distribution of dairy biomethane is not currently cost effective for the private developer without a public subsidy. In time, after a number of small-scale plants are built, costs are likely to come down.

Earlier in this chapter, we discussed the range of possible costs associated with the production of biomethane (Table 8-7). In general, costs for a biomethane plant on a dairy with 1,500 cows would be in the range of $11.54 per 1,000 ft^3. Based on the operating costs of several of the Swedish biogas upgrading plants, we projected that, at a very large dairy (8,000 cows) or centralized facility, the cost might be as low as $8.44 per 1,000 ft^3.

Table 8-10 compares our estimated costs for producing biomethane to current prices for natural gas. This comparison shows that on today's market, a large dairy could likely produce biomethane for a price lower than that paid by small retail commercial users (like dairies); while a smaller dairy's cost of production would be higher than the going market rate. As discussed earlier, current natural gas prices are at an historic high; wellhead prices in the 1990s, for example, averaged below $2.00 per 1,000 ft^3. Also, pioneering biomethane plants will be likely to incur higher costs due to inexperience, lack of qualified designers and contractors, and the need to educate public entities and regulators.

Table 8-10 Estimated Biomethane Production and Distribution Costs on Large (8,000 Cow) Dairy Compared to Current Natural Gas Prices

Biomethane			Natural Gas	
	Cost ($per 1,000 ft^3)			
Cost Category	Low	High	Price Category	Price [a] ($per 1,000 ft^3)
Production cost	$8.44	$11.54	Wellhead [b]	$6.05
Storage	$0.00	$2.80	City gate [b]	$7.44
Transportation	$0.00	$0.90	Distribution [c]	$9.84

[a] May 2005

[b] Source: US DOE Energy Information Administration website <http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm >

[c] Source: Pacific Gas and Electric Rate Information website <http://www.pge.com/rates/tariffs/GRF.SHTML#GNR1>

Unfortunately, production is only part of the story. Since it is unlikely that a farm could cost effectively use as much as half of the biomethane produced by an on-farm upgrading plant, most of the biomethane would need to be stored and transported to market. This adds significant costs to the enterprise. Private pipelines cost from $100,000 to $250,000 per mile, although they eliminate the need for storage. If the biomethane is trucked to market, it must first be stored until enough is accumulated to fill the tanker. Trucking itself is also expensive. The least costly means of biomethane distribution would be access to the natural gas pipeline grid, if a nearby pipeline were available. First, however, the farmer would have to overcome regulatory barriers and resistance from the gas utility; also, the gas utility would not pay the commercial price for the biomethane, but a price based on the wellhead or city gate price. Another possibility is that the dairy could *wheel* the gas via the natural gas grid, that is, pay a transportation fee to use the natural gas grid to convey the biomethane to a nearby industrial user. Producing and distributing LBM may be more economically favorable than other options.

In contrast, generating electricity from biogas can offset retail electric purchases and can be simpler and more profitable than biomethane production. However, there are problems with electrical generation. The farmer may produce more electricity than he can use, if this occurs, the farmer cannot be compensated for the excess electricity under California's current market structure, and the present net metering program in California is not as attractive for the small biogas electric generator as it is for the solar generator. Also, obtaining an interconnection agreement is time-consuming and expensive.

The biomethane industry, like the rest of the renewable energy sector, needs public subsidies, tax credits, or market rules that will help earn a premium for the product during its start-up phase. Regulators and lobbyists for the industry also need to be aware of the cost structure of the biomethane industry. In contrast to anaerobic digester systems that generate electricity, which have higher capital costs than operating costs, biogas upgrading plants that produce biomethane typically have higher operating costs than capital costs. Subsidies that cover even a large portion of the capital costs may be insufficient to stimulate industry growth. If biomethane facilities are to become viable, ongoing sources of renewable energy, they will likely need the support of ongoing production tax credits, a long-term fixed price contract, and/or market rules that provide a premium for its output.