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Biomethane from Dairy Waste

A Sourcebook for the Production and Use of Renewable Natural Gas in California

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Glossary

Acronyms and Abbreviations

AB	Assembly Bill
AFV	Alternate fuel vehicle
B100	Neat biodiesel, 100% biodiesel
B2	Diesel fuel containing 2% biodiesel
B20	Diesel fuel containing 20% biodiesel
BACT	Best available control technology
BDT	Bone dry tons
BOD	Biological oxygen demand
BRDA	Biomass Research and Development Act (2000)
Btu	British thermal units
CAFO	Confined animal feeding operation
CARB	California Air Resources Board
CBM	Compressed biomethane
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CFR	Code of Federal Regulations
CH_4	Methane
CHP	Combined heat and power
CNG	Compressed natural gas
CO	Carbon monoxide
CO_2	Carbon dioxide
CPUC	California Public Utility Commission
CWC	California Water Code
DGE	Diesel gallon equivalent
DMV	Department of Motor Vehicles
DOE EIA	U.S. Department of Energy, Energy Information Administration
DOT	U.S. Department of Transportation
DTSC	Department of Toxic Substance Control
E10	Gasoline fuel containing 10% ethanol
E85	Gasoline fuel containing 85% ethanol

E100	Gasoline fuel substitute containing 100% ethanol.
EQIP	Environmental Quality Incentives Program
ERC	Emission Reduction Credits
ft^3/d	Cubic feet per day
ft^3/h	Cubic feet per hour
ft^3/y	Cubic feet per year
FTP	Federal Test Procedure (US EPA)
FY	Fiscal year
GGE	Gasoline gallon equivalent
GHG	Greenhouse gas
gpd	Gallons per day
gpm	Gallons per minute
GVW	Gross vehicle weight
GW_e	Gigawatts of electricity (10^9 watts)
H_2	Hydrogen
H_2O	Water
H_2S	Hydrogen sulfide
H_2SO_4	Sulfuric acid
HOV	High-occupancy vehicle
hp	Horsepower
HRT	Hydraulic retention time
IOU	Investor owned utility
kW	Kilowatt (10^3 watts)
kWh	Kilowatt-hour
lb	Pound(s)
LBM	Liquefied biomethane
LCNG	Liquefied-to-compressed natural gas
LFG	Landfill gas
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MM	Millions
MTBE	Methyl tertiary-butyl ether
MW	Megawatt
MWh	Megawatt-hours

MW_e	Megawatts of electricity (10^6 watts)
NO_x	Nitrogen oxides and dioxides, typically NO and NO_2
N_2O	Nitrous oxide
NPDES	National Pollution Discharge Elimination System
PG&E	Pacific Gas and Electric Company
PIER	California's Public Interest Energy Research Program
PING	California's Public Interest Natural Gas Energy Research Program
PM	Particulate matter
POTW	Publicly owned treatment works
ppm	Parts per million
psi	Pounds per square inch
psig	Pounds per square inch, gauge
PURPA	Public Utility Regulatory Policy Act
PZEV	Partial zero-emission vehicle
RCRA	Resources Conservation and Recovery Act
ROG	Reactive organic gases
RPS	Renewable Portfolio Standard
scf	Standard cubic feet
scfm	Standard cubic feet per minute
SB	Senate Bill
SCE	Southern California Edison
SoCalGas	Southern California Gas Company
SULEV	Super ultra low-emission vehicle
TS	Total solids
ULEV	Ultra low-emission vehicle
USDA	US Department of Agriculture
US DOE	US Department of Energy
US EPA	US Environmental Protection Agency
VOC	Volatile organic compounds
VS	Volatile solids
ZEV	Zero-emission vehicle

Definitions

Acetic acid	A carboxylic acid, acetic acid is a relatively weak acid mainly used as a pH buffer (chemical formula CH_3 COOH).
Acidogenic	Acid-forming; used to describe microorganisms that break down organic matter to acids during the anaerobic digestion process
Anaerobic digestion	A naturally occurring biological process in which organic material is broken down by bacteria in a low-oxygen environment resulting in the generation of methane gas and carbon dioxide as its two primary products.
Anaerobic digester	A device for optimizing the anaerobic digestion of biomass and/or animal manure, often used to recover biogas for energy production. Commercial digester types include complete mix, continuous flow (horizontal or vertical plug-flow, multiple-tank, and single tank) and covered lagoon.
Biodiesel	Any liquid biofuel suitable as a diesel fuel substitute or diesel fuel additive or extender. Biodiesel fuels are typically made from oils such as soybeans, rapeseed, or sunflowers, restaurant waste greases, or from animal tallow using a transesterification process (though unprocessed oils are sometimes used). A bio-derived gasoline or diesel substitute can also be made from thermal gasification of biomass followed by a gas-to-liquids process (Fischer-Tropsch liquids).
Biofuel	Technically, any biomass derived substance used for energy (heat, power, or motive). The term 'biofuel' usually is used to describe liquid transportation fuels derived from biomass.
Biogas	A naturally occurring gas formed as a by-product of the breakdown of organic waste materials in a low-oxygen (e.g., anaerobic) environment. Biogas is composed primarily of methane (typically 55% – 70% by volume) and carbon dioxide (typically 30% – 45%). Biogas may also include smaller amounts of hydrogen sulfide (typically 50 – 2000 parts per million [ppm]), water vapor (saturated), oxygen, and various trace hydrocarbons. Due to its lower methane content (and therefore lower heating value) compared to natural gas, biogas use is generally limited to engine-generator sets and boilers

adapted to combust biogas as fuel. Biogas includes landfill gas, digester gas (from wastewater treatment plants) and biogas from the decomposition of animal waste or food processing waste. In this study the word biogas usually refers to biogas created by animal manure.

Biogas upgrading — A process whereby a significant portion of the carbon dioxide, water, hydrogen sulfide and other impurities are removed from raw biogas (digester gas) leaving primarily methane. Also referred to as “sweetening.” The major biogas upgrading technologies currently identified are water scrubbing, membrane separation, pressure swing adsorption, amine scrubbing (Selexol™ and COOAB™) and mixing with higher quality gases.

Biological oxygen demand — A measure of the amount of oxygen consumed in the biological processes that break down organic matter in water. Biological oxygen demand (BOD) is used as an indirect measure of the concentration of biologically degradable material present in liquid organic wastes. It usually reflects the amount of oxygen consumed in five days by biological processes breaking down organic waste. BOD can also be used as an indicator of water quality, where the greater the BOD, the greater the degree of pollution. Also referred to as “biochemical oxygen demand.”

Biomass — Biomass is any organic matter that is available on a renewable or recurring basis, including agricultural crops and trees, wood and wood wastes and residues, plants (including aquatic plants), grasses, residues, fibers, and animal wastes, municipal wastes, and other waste materials.

Biomethane — Biogas which has been upgraded or “sweetened” via a process to remove the bulk of the carbon dioxide, water, hydrogen sulfide and other impurities from raw biogas. The primary purpose of upgrading biogas to biomethane is to use the biomethane as an energy source in applications that require pipeline quality or vehicle-fuel quality gas, such as transportation. From a functional point of view, biomethane is extremely similar to natural gas except that it comes from renewable sources. (Note that the term “biomethane” has not yet come into popular usage;

	thus the term "biogas" is often used when referring to both the raw and upgraded forms of biogas/biomethane.)
Butyric acid	A carboxylic acid with structural formula $CH_3CH_2CH_2$-COOH. It is notably found in rancid butter, parmesan cheese, or vomit and has an unpleasant odor and acrid taste, with a sweetish aftertaste (similar to ether).
Cellulose	A complex carbohydrate, $(C_6H_{10}O_5)n$, that is composed of glucose units. Cellulose forms the main constituent of the cell wall in most plants.
Chemical oxygen demand	Chemical oxygen demand (COD) is used to indirectly measure the amount of all organic compounds in a water sample (whereas BOD indicates the amount of biodegradable compounds in solution). COD is widely used in municipal and industrial laboratories to measure the overall level of organic contamination in wastewater. COD is determined by measuring the amount of oxygen required to fully oxidize organic matter in the sample. A COD test requires approximately 3 hours to complete, while BOD requires 3-5 days.
Co-digestion	Co-digestion is the simultaneous digestion of a mixture of two or more feedstocks. The most common situation is when a major amount of a main basic feedstock (e.g., manure or sewage sludge) is mixed and digested together with minor amounts of a single or a variety of additional feedstocks. The expression co-digestion is applied independently to the ratio of the respective substrates used simultaneously.
Compressed biomethane	Compressed biomethane (CBM) is basically equivalent to compressed natural gas (CNG). The main difference is that CNG is made by compressing natural gas (a fossil fuel) whereas CBM is made by compressing biomethane (a renewable fuel).
Compressed natural gas	CNG is natural gas that has been compressed to 3,000 to 3,600 pounds per square inch, gauge (psig), usually for purposes of on-board fuel storage for natural gas vehicles.
Conventional pollutants	As specified under the Clean Water Act, conventional pollutants include suspended solids, coliform bacteria, biochemical oxygen demand, pH, and oil and grease.

Criteria air pollutants — As required by the Clean Air Act, the EPA identifies and sets standards to protect human health and welfare for six pollutants, called criteria pollutants: ozone (O_3). carbon monoxide (CO), particulate matter (PM10, PM2.5), sulfur dioxide (SO_2), lead (Pb), and nitrogen oxides (NO_x). The term “criteria pollutants” derives from the requirement that the EPA must describe the characteristics and potential health and welfare effects of these pollutants. Periodic reviews of new scientific data may lead the EPA to propose revisions to the standards.

Desulfurization — Any process or process step that results in removal of sulfur from organic molecules.

Dew point — The temperature at which vapor in a gas-vapor mixture starts to condense when the mixture is cooled at constant pressure (most commonly used for water vapor in gas mixtures).

Digester gas — Biogas that originates from an anaerobic digester. The term is often used, and used in this report, to represent only biogas from a wastewater treatment plant.

Economy of scale — The principle that higher volume production operations have lower unit costs than smaller volume operations.

Endothermic — A process or reaction that absorbs heat. For example, ice melting is an example of an endothermic process because it absorbs heat from its surroundings.

Enteric fermentation — A digestive process by which carbohydrates are broken down by microorganisms in the rumen to simple molecules for absorption into the bloodstream of a ruminant animal, such as a cow.

Ethanol — A colorless, flammable liquid (CH_3CH_2OH) produced by fermentation of sugars. Can be produced chemically from ethylene or biochemically from the fermentation of sugars. Ethanol from starch, especially corn, and sugar crops is commercial. Ethanol from cellulosic feedstocks (woody material and agricultural residues) is still being developed. Used in the United States as a gasoline octane enhancer and oxygenate, it increases octane 2.5 to 3.0 numbers at 10% concentration. Ethanol also can be used in higher concentration in alternative-fuel vehicles optimized for its use.

Exothermic	A process or reaction that releases heat. For example, wood burning in the presence of oxygen is an example of an exothermic reaction.
Global warming	An increase in the near surface temperature of the Earth. Global warming has occurred in the distant past as the result of natural influences, but the term is most often used to refer to the warming that occurs as a result of increased emissions from human activity of greenhouse gases, such as carbon dioxide, methane, and nitrous oxide, which trap the sun's heat.
Hemicellulose	A carbohydrate polysaccharide that is similar to cellulose and is found in the cell walls of many plants
Hydraulic retention time	HRT is the average time a 'volume element' of fluid resides in a reactor. It is computed from liquid-filled volume of an anaerobic digester divided by the volumetric flow rate of liquid medium.
Landfill gas	Biogas produced as a result of natural, anaerobic decomposition of material in landfills. Landfill gas (LFG) is typically composed of approximately 55% methane and 45% CO_2, with variable air content due to air introduced during the LFG collection process. Small amounts of H_2S, siloxanes, other sulfur compounds, various trace hydrocarbons and other impurities can be present which provide a significant challenge in LFG handling and upgrading.
Ligno-cellulosic	Consisting of cellulose intimately associated with lignin, an amorphous polymer related to cellulose that has strength and rigidity. Wood is the most abundant ligno-cellulosic material, though almost all plant biomass contains lignin. Lignin does not degrade anaerobically (and is the most recalcitrant component of biomass for aerobic decomposition). Because of the structural nature of ligno-cellulosic material, much of the cellulose is difficult to access for anaerobic digestion.
Liquefied biomethane	Liquefied biomethane (LBM) is basically equivalent to LNG (liquid natural gas). The main difference is that LNG is made using natural gas (a fossil fuel) as a feedstock whereas liquefied biomethane is made using biomethane (a renewable fuel) as a feedstock.

Liquefied natural gas	A natural gas in its liquid phase. Liquefied natural gas (LNG) is a cryogenic liquid formed by cooling natural gas to approximately - 260º F at atmospheric pressure. In practice, LNG is typically stored at somewhat elevated pressures (e.g., 50 to 75 psig) to reduce cooling requirements and allow for pressure increases due to LNG vapor “boil off.” LNG is stored in double-insulated, vacuum-jacketed cryogenic tanks (pressure vessels) to minimize warming from the external environment. LNG is typically greater than 99% methane.
Mesophilic	Conditions in a biological reactor where temperatures are around 95° F (35° C).
Methanogenic	Methane-forming; In the anaerobic digestion process, methanogenic bacteria consume the hydrogen and acetate (from the hydrolysis and the acid forming stages) to produce methane and carbon dioxide
Methane	Methane is the main component of natural gas and biogas. It is a natural hydrocarbon consisting of one carbon atom and four hydrogen atoms (CH_4). The heat content of methane is approximately 1,000 Btu/scf (standard cubic feet). Methane is a greenhouse gas with 21 times the global warming potential of carbon dioxide on a weight basis.
Nameplate rating	The initial capacity of a piece of electrical equipment as stated on the attached nameplate in watts, kilowatts or megawatts. Actual capability can vary from the nameplate rating due to age, wear, maintenance, fuel type or ambient conditions.
Natural gas	Natural gas typically contains more than 90% methane; it may also contain traces of propane and butane. Natural gas is generally found either above crude oil deposits or in a relatively pure form in “stranded” natural gas fields. The methane content varies considerably in natural gas geologic reservoirs (deposits). Low-methane natural gas (sour gas) must be sweetened or upgraded before it can enter the natural gas grid. Sour gas or stranded gas often occurs in quantities too small to be economically processed and gathered into the pipeline network. Thus, it is often burned off near the well (i.e., flared) as a low-value by-product during the oil pumping process. Natural gas is a vital fossil fuel that is used in electricity generation, heating,

	fertilizer production, the creation of plastics, and other industrial processes and products.
Net metering	A method of crediting customers for electricity that they generate on-site in excess of their own electricity consumption. Customers with their own generation offset the electricity they would have purchased from their utility. If such customers generate more than they use in a billing period, their electric meter turns backwards to indicate their net excess generation. Depending on individual state or utility rules, the net excess generation may be credited to their account (in some cases at the retail price), carried over to a future billing period, or ignored.
Nitrogen or nitric oxides	NO_x is a regulated criteria air pollutant, primarily NO (nitric oxide) and NO_2 (nitrogen dioxide). Nitrogen oxides are precursors to photochemical smog and contribute to the formation of acid rain, haze and particulate matter.
Nitrous oxide	N_2O, a greenhouse gas with 310 times the global warming potential of carbon dioxide.
Nonconventional pollutants	Pollutants not classified as conventional or toxic but which may require regulation. They include nutrients such as nitrogen and phosphorus.
Nonpoint source	Pollution source that is diffuse, without a single identifiable point of origin, including runoff from agriculture, forestry, and construction sites.
Point source	Contamination or impairment from a known specific point of origination, such as sewer outfalls or pipes.
Priority (toxic) pollutants	Pollutants that are particularly harmful to animal or plant life. They are grouped primarily into organics (including pesticides, solvents, polychlorinated biphenyls (PCBs and dioxins) and metals (including lead, silver, mercury, copper, chromium, zinc, nickel, and cadmium).
Propionic acid	The chemical compound propionic acid (systematically named propionic acid) is a naturally occurring carboxylic acid with chemical formula CH_3CH_2COOH. In the pure state, it is a

	colorless, corrosive liquid with a sharp, somewhat unpleasant odor. Found in milk, sweat, and fuel distillates
Reactive organic gases	A term used by the California Air Resources Board as interchangeable with *volatile organic compounds*.
Rumen	The large first compartment of a ruminant's stomach in which cellulose is broken down by the action of symbiotic microorganisms.
Scrubbing	Cleaning emission gases from a chemical reactor, generally with sprays of solutions that will absorb gases.
Stoichiometric	Pertaining to the proportion of chemical reactants in a specific reaction in which there is no excess of any reactant. For combustion, stoichiometric is the theoretical condition at which the proportion of the air-to-fuel is such that all combustible reactants will be completely burned with no oxygen or fuel remaining in the products.
Thermal gasification	Thermal gasification typically refers to conversion of solid or liquid carbon-based materials by direct internal heating provided by partial oxidation. The process uses substoichiometric air or oxygen to produce fuel gases (synthesis gas, producer gas), principally CO, H_2, methane, and lighter hydrocarbons in association with CO_2 and N_2 depending on the process used. Thermal gasification can convert all of the organic components of the feedstock, whereas anaerobic digestion cannot convert lignin and some lignin/cellulose matrices. Generally lower moisture feedstocks are candidates for thermochemcial conversion while high moisture feedstocks are best converted by biochemical means.
Thermophilic	Conditions in a biological reactor where temperatures are around 130° F (55° C) or higher.
Total Solids	Used to characterize digester systems input feedstock. Total solids (TS) means the dry matter content, usually expressed as % of total weight, of the prepared feedstock. By definition, TS = 100% – moisture content % of a sample. Also, TS = VS plus ash content.

Volatile organic compounds VOCs are non-methane, non-ethane, photoreactive hydrocarbon gases that vaporize at room temperature (methane and ethane are not photoreactive). The quantity of VOC is sometimes determined by measuring non-methane non-ethane organic compounds. When combined with NO_x and sunlight, VOCs produce ozone, a criteria air pollutant. Anthropogenic sources of VOCs include products of incomplete combustion, evaporation of hydrocarbon fuels, fugitive emissions from oil refineries and petro-chemical plants, fermented beverage manufacturing, large animal feeding operations and feed ensiling. However, natural VOC emissions account for the majority of VOC emissions (approximately 60% of the US VOC emission inventory). Vegetation, especially hardwood and pine trees account for most of the natural VOC emissions. They are also an intermediate product in the creation of methane during anaerobic digestion and are produced during enteric fermentation.

Volatile Solids Used to characterize digester systems input feedstock Volatile Solids (VS) are the organic (carbon containing) portion of the prepared reactor feedstock. Usually expressed as a fraction of total solids, but sometimes expressed as a fraction of total sample (wet) weight. The amount of VS in a sample is determined by an analytical method called “loss on ignition.” It is the amount of matter that is volatilized and burned from a sample exposed to air at 550 ºC for 2 hours. The inorganic (ash) component of total solids remains after the loss on ignition procedure. VS + ash = TS. Not all of the VS component of a feedstock is digestible.

Wheeling The process whereby owners of electricity or natural gas pay to transport and distribute their commodity through another entity’s, distribution system (wire or pipeline grid).

Executive Summary

This report examines the feasibility of producing biomethane from dairy manure. We investigated a number of possible technologies for producing renewable forms of energy and fuel from dairy wastes as well as applications and markets for these products. Although some of the applications proved to be technically or economically infeasible at this time, we believe that the information gathered could prove useful for other investigators or future studies. With this in mind, we designed this sourcebook for readers and investigators interested in exploring alternate uses of biogas created from dairy wastes.

Summary of Findings

- Biomethane is renewable natural gas. It is made by upgrading biogas that is produced by the controlled decomposition of dairy manure or similar waste products. It can serve as a substitute for natural gas in transportation, heating, cooling, and power generation.
- Producing biomethane from dairy manure is not technically difficult, but it is challenging to produce it cost competitively with natural gas on the relatively small scale of a dairy.
- Dairies can produce more biomethane than they can use. A successful project must identify an off farm use, and provide a means to transport and store the fuel.
- There are institutional and regulatory barriers to transporting biomethane through the natural gas pipeline which will be difficult to overcome. Alternatively, it can be transported by dedicated pipeline or truck.
- Biomethane provides a number of societal and environmental benefits, especially improved energy security and reduced greenhouse gas emissions. Unlike raw biogas which has impurities that corrode exhaust systems, NO_x emissions from biomethane combustion can be easily controlled.
- Current Federal and State programs provide little support for biomethane.
- The estimated cost of producing biogas and upgrading it to biomethane on farm can be competitive with the price the dairy would pay for natural gas. Added to the production cost is the cost of transportation and storage.
- Electrical generation from biogas is more cost effective than upgrading the biogas to biomethane, but current regulations make it difficult for the farmer to realize the economic value of the electricity he/she generates.
- Biomethane is a proven vehicle fuel. Sweden has 20 plants producing biomethane and runs 2,300 vehicles, mostly buses on it.
- Manure from about half the cows in California could provide enough biomethane to power all the natural gas vehicles currently operating in the state.

Summary of Opportunities

- Central Valley cities such as Tulare, Visalia, Hanford or Modesto would be good sites for a biomethane vehicle fuel project because they are in a non-attainment area for ozone, and they each have many dairies in close proximity to existing compressed natural gas filling stations. To make these projects feasible, the cities would need to enlarge their natural gas fleets (natural gas vehicles have lower air emissions than diesel vehicles) and expand or reconfigure their filling stations.

- There are many industrial customers in the Central Valley that could use large quantities of locally produced biomethane, though raw or partially cleaned biogas may suffice in many industrial applications.
- The output of Central Valley liquefied biomethane plants could replace the liquefied natural gas currently trucked in from other states.
- A biomethane industry along California's Highway 99 could serve as the infrastructure for a future "hydrogen highway," should it prove feasible, because it would provide a renewable fuel to replace natural gas as a feedstock for the on-site manufacture of hydrogen.

Structure of Report

The report deals with five major areas of investigation:

- *Producing biogas from California dairy wastes*. We considered the theoretical maximum production potential, the technical and economic considerations, and the technologies and systems most suitable for producing biogas on dairy farms.
- *Upgrading biogas to biomethane*. We use the term "biomethane" to describe an upgraded form of biogas similar to natural gas in composition and energy capacity, and we investigated the various technologies that can be used to create biomethane by removing hydrogen sulfide, moisture, and carbon dioxide from biogas.
- *Using and distributing biogas and biomethane*. We investigated various traditional and non-traditional uses of biogas and considered potential on- and off-farm uses of biomethane. An important consideration is the means of storing and transporting the fuel to its final place of consumption. We considered the technical and economic implications of the various means of distribution.
- *Meeting regulatory requirements and obtaining access to government incentives*. Most existing government policies and incentives for renewable energy focus either on renewable electricity sources or two forms of alternative vehicle fuels: ethanol and biodiesel. We examined federal and state (California) policies and programs now in place to determine their current or potential applicability to the dairy biogas and biomethane industry. We also considered the various permits and regulatory requirements needed to build a dairy digester and/or biomethane upgrading plant, whether on an individual farm or at a centralized location.
- *Determining the financial, economic, and business environment for the development of a biomethane industry*. We estimated the costs of building a biomethane plant and considered these in the context of existing and potential markets for biomethane. Despite some favorable economic conditions, such as the currently high price of natural gas, we concluded that public (i.e., governmental) policy support of the industry is needed to help move it beyond the pioneering stage, and we concluded that the various environmental, social, and economic benefits associated with the development of such an industry justify this support. We also determined a logical process for analyzing and developing specific biomethane projects and provided some scenarios for five projects that we believe have the best chance for success.

Producing Biogas from California Dairy Wastes

California is the largest dairy state in the USA, with approximately 1.7 million cows that produce over 20,000 pounds of milk per cow each year. These same cows also generate approximately 3.6 million bone dry tons of manure, which must be properly managed to minimize air emissions, prevent water pollution, and control odor, flies, and pathogens.

Biogas, a mixture consisting primarily of methane and carbon dioxide, is produced from dairy wastes through anaerobic digestion, a natural process that breaks down organic material in an oxygen-free environment. This process occurs unaided at dairies that store their wastes in covered piles or lagoons, with the resulting biogas and its greenhouse gases typically released into the atmosphere. Anaerobic digesters allow dairies to produce and capture biogas that can be used as a renewable source of energy. Most dairies currently using anaerobic digesters for energy production capture the biogas and burn it as a source of renewable electricity for on-farm operations. Anaerobic digesters also help control odors, flies, and pathogens.

Methane Production Potential of Dairy Wastes and Other Biomass

Nearly two-thirds of all cows in California are on dairies that use a flushed management system; the others use a scrape system. In practice, flush dairies are the best candidates for biogas production because manure that is scraped and stored typically decomposes aerobically, which inhibits the development of the bacteria that create biogas. Potentially, California dairies could generate nearly 14.6 billion ft^3 of methane each year (which corresponds to 140 megawatts of electrical capacity); however, this figure does not reflect the practicalities of manure collection and storage.

Dairy wastes can be co-digested with other biomass, such as agricultural residues or food-processing wastes, to augment methane production. Co-digestion of animal manures with food processing wastes in community digestion facilities is practiced in a number of European locations and could be applicable also in some dairy areas in California. The practical potential methane production from all biodegradable sources in California is about 23 billion ft^3 per year (220 megawatts); dairy wastes make up nearly two-thirds of this amount. If all theoretically available feedstocks were used and better technologies were developed, the potential is five or six times greater.

Technical Considerations for Anaerobic Digestion

Key considerations in the design of an anaerobic digester include the amount of water and inorganic solids that mix with manure during collection and handling. The anaerobic digester itself is an engineered containment vessel designed to exclude air and promote the growth of methanogenic bacteria. The three digester types most suitable for California dairies are ambient-temperature covered-lagoon, complete-mix, and plug-flow digesters.

Collection and Use of Biogas

Biogas formed in the anaerobic digester bubbles to the surface where it is captured. Sometimes the biogas is scrubbed to reduce the hydrogen sulfide content. Depending on the application, biogas may be stored either before or after processing, at low pressures. More often recovered biogas is fed directly into an internal combustion engine to generate electricity and heat, or it can be used only for heating. If the biogas is upgraded to biomethane, additional uses are possible.

Upgrading Dairy Biogas to Biomethane and Other Fuels

By removing hydrogen sulfide, moisture, and carbon dioxide, dairy biogas can be upgraded to biomethane, a product equivalent to natural gas, which typically contains more than 95% methane. The process can be controlled to produce biomethane that meets a pre-determined standard of quality. Biomethane can be used interchangeably with natural gas, whether for electrical generation, heating, cooling, pumping, or as a vehicle fuel. Biomethane can also be pumped into the natural gas supply pipeline. High pressures can be used to store and transport biomethane as compressed biomethane (CBM), which is analogous to compressed natural gas (CNG), or very low temperatures can be used to produce liquefied biomethane (LBM), which is analogous to liquefied natural gas (LNG).

Technologies for Upgrading Biogas to Biomethane

The technologies for upgrading biogas are well established. They are used in the natural gas industry to “sweeten” sour gas, i.e. natural gas that is low in methane content. They have also been used at a few US landfills, but in all cases the scale is much larger than the average dairy.

There are three steps to upgrading biogas to biomethane. They are: (1) removal of hydrogen sulfide, (2) removal of moisture, and (3) removal of carbon dioxide. The simplest way to remove moisture is through refrigeration. H_2S can be removed by a variety of processes:

- Air injected into the digester biogas holder
- Iron chloride added to the digester influent
- Reaction with iron oxide or hydroxide (iron sponge)
- Use of activated-carbon sieve
- Water scrubbing
- Sodium hydroxide or lime scrubbing
- Biological removal on a filter bed

The following processes can be considered for CO_2 removal from dairy manure biogas. Some of them will also remove H_2S. The processes are presented roughly in the order of their current availability for and applicability to dairy biogas upgrading:

- Water scrubbing
- Pressure swing adsorption

- Chemical scrubbing with amines
- Chemical scrubbing with glycols (such as Selexol™)
- Membrane separation
- Cryogenic separation
- Other processes

Some technologies are more suitable for dairy farm operations than others, typically because of cost considerations, ease of operation, and other concerns such as possible environmental effects. A possible design for a small dairy biogas upgrading plant might consist of the following:

- Iron sponge unit to remove hydrogen sulfide
- Compressors and storage units
- Water scrubber with one or two columns to remove carbon dioxide
- Refrigeration unit to remove water
- Final compressor for producing CBM, if desired

Operation and maintenance of this system would be relatively simple, which is one reason it is recommended over other, possibly more efficient, processes. Electricity for the compressors could be produced from an on-site generator using biogas, which could also generate power for other on-site uses, or from purchased power. If purchased power were used, the major operating costs for this process would be for power for gas compression. Our research suggests that a farm of about 1,500 dairy cows is the lower limit of scale for this technology.

Potential for Upgrading to Fuels other than Biomethane

Other potential high-grade fuels that could possibly be produced from biogas include (1) liquid hydrocarbon replacements for gasoline and diesel fuels (created using the Fischer-Tropsch process), (2) methanol, and (3) hydrogen. At present, however, technological constraints, poor economies of scale for small operations, and—in the case of methanol—a lack of markets, make these processes impractical for dairy operations.

Storing, Distributing, and Using Biogas and Biomethane

Dairy manure biogas is generally used in combined heat and power applications that combust the biogas to generate electricity and heat for on-farm use as it is created. Because of its highly corrosive nature (due to the presence of hydrogen sulfide and water) and its low energy density (as obtained from the digester, biogas contains only about 600 Btu/scf), the potential for off-farm use of raw biogas is extremely low.

Biomethane, which was upgraded from biogas by removing the hydrogen sulfide, moisture, and carbon dioxide, has a heating value of about 1,000 Btu/scf. Because of this high energy content, biomethane can be used as a vehicular fuel. It could also be sold for off-farm applications to industrial or commercial users or for injection into a natural gas pipeline.

Storage of Biogas and Biomethane

The least expensive and easiest to use storage systems for on-farm applications are low-pressure systems; these systems are commonly used for on-site, intermediate storage of biogas. Floating gas holders on the digester form a low-pressure storage option for biogas systems.

The energy, safety, and scrubbing requirements of medium- and high-pressure storage systems make them costly and high-maintenance options for biogas. They can be best justified for biomethane, which is a more valuable fuel than biogas.

Biomethane can be stored as CBM to save space or for transport to a CNG vehicle refueling station. High-pressure storage facilities must be adequately fitted with safety devices such as rupture disks and pressure relief valves. Typically, a low-pressure storage tank is used as a buffer for the output from the biogas upgrading equipment and would likely have sufficient storage capacity for around one to two days worth of biogas production. Since CNG refueling stations normally provide CNG at 3,000 to 3,600 psi, biomethane is compressed and transported at similar or higher pressures to minimize the need for additional compression at the refueling station.

Biomethane can also be liquefied to LBM. Two advantages of LBM are that it can be transported relatively easily and it can be dispensed to either LNG vehicles or CNG vehicles. However, if LBM is to be used off-farm, it must transported by tanker trucks, which normally have a 10,000-gallon capacity. Since LBM is a cryogenic liquid, storage times should be minimized to avoid the loss of fuel by evaporation through tank release valves, which can occur if the LBM heats up during storage.

Distribution of Biomethane

Biogas is a low-grade, low-value fuel and therefore it is not economically feasible to transport it for any distance, although occasionally it is transported for short (1 or 2 mile) distances via a dedicated pipeline. In contrast, biomethane can be distributed to its ultimate point of consumption by dedicated biomethane pipelines, the natural gas pipeline grid, or in over-the-road transportation as CBM or LBM.

If the point of consumption is relatively close to the point of production, the biomethane could be distributed via dedicated pipelines (buried or aboveground). For short distances over property where easements are not required, this is usually the most cost-effective method. Costs for laying dedicated biomethane pipelines can vary greatly, and range from about $100,000 to $250,000 per mile.

The natural gas pipeline network offers a potentially unlimited storage and distribution infrastructure for biomethane. Once the biomethane is injected into the natural gas pipeline network, it becomes a direct substitute for natural gas. There is at least one location in the US (at the King County South Wastewater Treatment Plant in Renton, Washington) where this is done.

The gas can be sold to a utility, or wheeled to a contracted customer. However there are substantial regulatory and other barriers involved in using the natural gas pipeline.

If distribution of biomethane via dedicated pipelines or the natural gas grid is impractical or prohibitively expensive, over-the-road transportation of compressed biomethane may be a distribution option.

Over-the-road transportation of liquefied biomethane is a potential way of addressing many of the infrastructure issues associated with biomethane distribution. In California, where almost all LNG is currently imported from other states, in-state production of LBM would gain a competitive advantage over LNG with respect to transportation costs.

Biogas as a Fuel for On-Farm Combined Heat and Power Applications

At present, dairy manure biogas is used on-farm for direct electrical generation, and some of the waste heat is recovered for other uses. Because of its highly corrosive nature (due to the presence of hydrogen sulfide and water) and its low energy density, the potential for off-farm use of biogas is limited.

Electricity generation using biogas on dairy farms is a commercially viable, proven renewable energy technology. Typical installations use spark-ignited natural gas or propane engines that have been modified to operate on biogas. Gas treatment to prevent corrosion from hydrogen sulfide is usually not necessary if care is taken with engine selection and proper maintenance procedures are followed, though it may become necessary in the future to help control NO_x from combustion.

Burners and boilers used to produce heat and steam can be fueled by biogas if the equipment is modified to ensure the proper fuel-to-air ratio during combustion and if operating temperatures are maintained at a high enough level to prevent condensation and the resultant corrosion from the hydrogen sulfide contained in the biogas.

For combined heat and power (CHP) applications, the key to energy savings is recovering heat generated by the engine jacket and exhaust gas. Nearly half of the engine fuel energy can be recovered through this waste heat by, for example, recovering hot water for process heat, preheating boiler feedwater, or space heating.

Alternative On-Farm Uses of Biogas

Theoretically, biogas can replace other fuels for on-farm non-CHP applications such as irrigation pumps and engine-driven refrigeration compressors, but this is unlikely. Raw biogas cannot be used as a vehicular fuel because of engine and performance maintenance concerns.

Spark-ignited gasoline engines may be converted to operate on biogas by changing the carburetor to one that operates on gaseous fuels (some gas treatment may be necessary). Diesel engines can also be modified to operate on biogas; the high compression ratio of a diesel engine lends itself to operation on biogas.

Irrigation pump use is intermittent and highly seasonal and therefore would not consume biogas on a steady basis throughout the year. Also, it would probably be more cost-efficient to switch remote diesel-powered irrigation pumps to electrical power (which could be provided by a generator set using “raw” biogas as fuel) than to upgrade the biogas and transport it via pipeline to feed the remote irrigation pumps.

Refrigeration accounts for about 15% to 30% of the energy used on dairy farms; most of this is for compressors used for chilling milk. Since dairy cows are milked daily, a steady source of energy is required for refrigeration needs. However, natural-gas driven motors are significantly more expensive than electrical motors with similar output power ranges and therefore have not been traditionally considered as economically desirable choices for this application. Thus, the use of biogas as a direct fuel for on-farm refrigeration compressors is not likely.

Potential On-Farm Uses of Biomethane

All the equipment described above that can run on biogas or natural gas can run on biomethane. In addition biomethane is suitable as a fuel in vehicles converted or designed to run on natural gas. Biomethane could be moved around a farm more easily than biogas because it is a cleaner fuel; however, it will likely still be more cost-effective to use biogas to generate electricity to run irrigation pumps than to convert the pumps to run on biomethane. The same is true of refrigeration equipment which could be run by electricity or driven by waste heat.

Although it is technically feasible to use biomethane as a fuel for on-farm alternative-fueled vehicles, there are currently no commercially available CNG- or LNG-fueled non-road agricultural vehicles. Commercial versions of some on-road agricultural vehicles such as pickup trucks are available, but the lack of convenient refueling infrastructure, makes it difficult to use CNG or LNG vehicles for on-farm applications.

Off-Farm Uses of Biomethane

There are two main potential off-farm uses of biomethane: to sell it to a nearby industrial user with heavy natural gas requirements or to sell it as a vehicular fuel. The major considerations for the first use is (1) to locate an industrial user willing to buy biomethane and (2) to transport the biomethane to the industrial user economically. There are many industrial users in the Central Valley that could use very large amounts of biomethane. Dairy cooperatives use large amounts of natural gas to dry milk into powder.

The medium- and heavy-duty CNG vehicle market is expected to be fueled by continued strong demand for CNG transit buses and to a lesser extent, school buses and refuse trucks. Given the potential variability in the medium- and heavy-duty market, a range of projections has been given based on a conservative annual growth rate of 15% to 20%.

The heavy-duty market accounts for the vast majority of the LNG vehicles in California. In general, the growth in this market is expected to be fueled by continued niche demand for LNG transit buses, refuse trucks, and Class 8 urban delivery trucks (regional heavy delivery). Growth is limited by the lack of a refueling infrastructure and of in-state LNG production facilities. The market is expected to grow from its small base by 5% to 10% a year.

The combined annual market for CNG and LNG vehicle fuel in California is approximately 80 million gasoline gallon equivalents. To put this in perspective, it would take methane from about 900,000 cows, about half the cows in the state, to provide this amount of fuel.

Meeting Regulatory Requirements and Gaining Access to Government Incentives

The successful development of a California biomethane industry will require supportive government policies and financial incentives. The production and use of biomethane as a replacement for fossil fuels could potentially provide numerous benefits such as reduced greenhouse gas, reduction of odors and flies on the dairy, less dependence on fossil fuel supplies, better energy security, stimulation of rural economies, and could possibly improve water quality. These are benefits to society rather than financial benefits for the farmer who produces the biomethane. Consequently, it is appropriate for the government to provide support for the development of the biomethane industry.

Unfortunately biomethane does not get as much governmental support as other renewable energy sources. Most federal and state policies that support renewable energy and alternative fuels focus either on renewable electricity, often referred to as renewable energy, or on two specific liquid biofuels: ethanol and biodiesel. With a few exceptions, they do not provide specific support for biomethane production. If the biomethane industry is to prosper, it must help launch policy initiatives that will provide the same direct financial incentives or tax credits that are now earned by programs that focus on renewable electricity, ethanol, and biodiesel.

Policy Responses to Environmental Issues

Public policy is moving to address emissions from dairy biogas; it remains to be seen whether this takes shape as increased regulatory efforts, market incentives such as a carbon trading market or an emission reduction credit market, or the development and promotion of technologies that will help dairies or other sources voluntarily reduce their emissions.

Regulation to Control Dairy and Vehicle Emissions

Federal and state policies are already in place to help regulate air quality. Although, the application of these policies to agricultural activities such as dairy farming has been minimal to date, recent changes in California law require California air districts to regulate dairies in accordance with the federal Clean Air Act. Since the San Joaquin Valley and the South Coast are extreme non-attainment areas for ozone, major sources of pollution in those air districts need to control their volatile organic compound emissions. As a result both districts have considered anaerobic digesters to control VOC as a possible requirement in some cases, or as a mitigation measure. However, anaerobic digesters should be viewed primarily as a renewable energy technology rather than as an air quality control technology.

Market Incentives to Reduce Pollution

Two types of emission trading permits could impact the biogas/biomethane industry in the USA: carbon trading and emission reduction credits. Although carbon trading is unlikely in the near future unless the USA ratifies the Kyoto Treaty, California has a market in place for emission reduction credits. As currently structured, this market does not allow agricultural enterprises to participate effectively; however, if such participation were possible, dairies might be provided with an incentive to collect biogas, thus potentially reducing volatile organic compound (VOC) emissions and gaining emission reduction credits.

Promotion of New Energy Technologies and Fuels

There are several approaches that can help encourage new technologies: tax credits or incentives, subsidies through direct funds, and long-term contracts that guarantee market and/or price. For example, in response to concerns about the contribution of methane to climate change, the US EPA set up the AgSTAR program to develop and disseminate information about anaerobic digesters for animal waste. The California Energy Commission has also funded research on anaerobic digestion for electrical production and has a new program natural gas research program that may fund biomethane research.

Financial Incentives

Renewable electricity, ethanol, and biodiesel are supported by direct financial incentives and mandates that increase their usage, while biomethane does not.

California is committed to renewable electricity and has a variety of programs that provide direct benefits for electrical generation, but the dairy loses them when it chooses to use its biogas for biomethane instead of electricity.

Ethanol has direct cash incentives in excise tax exemptions that began in 1978. Both ethanol and biodiesel are also supported by producer incentive funds under the 2002 Farm Bill. The ethanol market is also supported by oxygenation mandates under the Clean Air Act amendments of 1990.

Traditional biofuels and biomethane receive some market support through the alternative fuel program created by the Energy Policy Act of 1992, which may be expended in the proposed Energy Policy Act of 2005. Vehicles that run on biomethane fulfill alternative vehicle fleet requirements as mandated in federal, state, and local law and should be able to earn various federal, state, and local incentives.

Biomethane receives no direct financial incentives, although it can qualify for some of the benefits available to alternative fuels. The federal government has programs to promote farm-based and rural renewable energy, and biomethane projects can compete for such awards. The federal government's efforts are concentrated in the Farm Bill of 2002. In addition, biomethane research and development funds are available through competitive grant programs.

Government Permits and Regulations for Biogas Upgrading Plant

A biogas upgrading facility is subject to federal, state, and local regulatory requirements. The dairy itself is subject to a number of air and water quality regulations, whether or not it produces biogas. Even if a dairy has a water permit, a new permit is required for the installation of an anaerobic digestion system. If a dairy has a digester that combusts biogas, or upgrades biogas to biomethane, an air permit will be required from the local air district. Depending on the county, a local administrative permit or conditional use permit may also be required.

No specific additional permits are needed by an upgrading facility to compress or liquefy biomethane to produce CBM or LBM. However, there may be emission or safety issues associated with the production of these fuels that will make it more difficult to meet permitting requirements.

Regulations pertaining to over-the-road transportation of CNG and LNG are assumed to be fully applicable to over-the-road transportation of CBM and LBM, respectively.

No known federal, state, or local regulations expressly prohibit the distribution of dairy based biomethane via the natural gas pipeline network, though there is a California regulation that blocks landfill generated biomethane from the natural gas pipeline. Yet only one US biomethane plant, the aforementioned wastewater treatment plant in Renton, Washington, puts biomethane into the natural gas pipeline. Regulatory barriers and utility resistance are likely to make this alternative very challenging.

It is unclear whether state and county regulations pertaining to local pipeline distribution of natural gas would be applicable to the local distribution of biomethane (or biogas) via dedicated pipelines. More than likely, the use of a dedicated pipeline to transport biogas or biomethane in a gas utility service area would be subject to the standard city and county regulations and permitting process for underground pipe installations. Some local regulations specify that permits for underground pipelines carrying gas can only be granted to public utilities. For this reason, having a local utility company as a partner in a biogas/biomethane project could be an important asset during the permitting process.

Obtaining the necessary permits for siting, constructing, and operating dedicated biogas/biomethane pipelines could be a complex, time-consuming, and expensive process depending on the location of the proposed pipelines (i.e., what land they will cross). Permits from state, local, and possibly federal agencies may be required.

Determining the Financial, Economic, and Business Environment for the Development of a Biomethane Industry

As sources of renewable energy, biogas and biomethane compete in one of two markets: electricity and natural gas (including natural gas vehicle fuels). To be viable energy sources, they must be able to compete in these markets from a financial and economic standpoint.

California's Electricity and Natural Gas Markets

Electricity is different from all other commodities in that it cannot be stored; it must be generated on demand, when it is needed. Thus the capacity of the system is as important as the quantity of electricity that is generated. Despite the 1996 restructuring of California's electricity market, it remains regulated and strapped by complex rules.

Electricity price analysis in California is complex because the retail price includes many components in addition to charges for electricity generation. In addition, 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. Their best alternative is to use it on-farm availing themselves of opportunities presented under California's net metering legislation (AB 2228, proposed AB 728). Inasmuch as they use the electricity on-farm without sending it through the grid, they save the full retail price of electricity.

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.

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 very high price historically.

In all likelihood, biomethane production will be cost effective only if it 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. The most promising off-site customers would be a nearby alternative vehicle fueling station (for CBM or LBM) or an industrial user of large amounts of natural gas.

Estimated Costs for Building a Biogas Fueled Electric Plant or Biomethane Upgrading Plant

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. The second component is the system to generate the electricity.

A dairy anaerobic digester whose ultimate purpose is to produce biomethane uses the same sort of digester to generate and collect biogas. The biogas is then upgraded to biomethane by removing the hydrogen sulfide, moisture, and carbon dioxide. Finally, the biomethane is compressed or liquefied, stored, and/or transported to a location where it can be used.

Estimated Costs for Anaerobic Digesters for Electricity Generation

We analyzed the published costs for 12 dairy digesters larger than 50 kW and found that the average cost for building the anaerobic digester systems for electrical generation 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, we calculated cost ranges for the various digesters, both with and without equipment to remove nitrogen oxide emissions. Of course costs for specific projects vary considerably from these averages based on local conditions.

At the lower average cost of $4,500 per average kilowatt generated, the capital costs for a digester-generator with a capacity of about 100-kW would be about $450,000 (without NO_x controls). At 28% efficiency, with operating costs included and with the plant fully amortized over 20 years at 8%, this plant would have a levelized cost of electricity of $0.067/kWh. If controls for NO_x emissions were added (another $90,000 in capital costs), the levelized cost of electricity would go up to about $0.077/kWh. If waste heat is used for some on-farm uses, the estimated costs for both ranges will decrease. 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 (for a $4,500/kw digester) to $0.077/kWh (for a $6,100/kw digester). These costs compare favorably with the retail price the farmer is paying, currently $0.09 to $0.11/kWh, but they are not competitive in the wholesale market.

Estimated Costs to Upgrade Biogas to Biomethane

Estimating the costs of a biogas to biomethane plant is more speculative than for a digester-generator. Although several large-scale upgrading plants have been built and operated at landfills, to date, no biogas upgrading facility has been built on a dairy in the USA. Sweden, however, has 20 plants that produce biomethane from various sources of biomass. Several of the authors of this report visited Sweden in June 2004 to tour biomethane plants and were able to obtain cost data on four biomethane plants. All four plants were municipally run centralized plants that processed a variety of feedstocks.

The scale of the Swedish biomethane plants is smaller than the few landfill-gas upgrading plants in the USA, but larger than what would be required for most dairy facilities. For example, the largest plant we visited would require raw biogas from 27,000 cows to generate the amount of biomethane they produce, while the mid-sized plants would require 7,000 to 10,000 cows each, and the smallest plant could operate with manure from 1,500 to 2,000 cows. Each of these plants removes hydrogen sulfide, moisture, and carbon dioxide from the raw biogas and places the resultant biomethane into a pipeline, or compresses it for storage and/or transportation.

The capital costs of the smallest Swedish biogas upgrade plant were \$2.20 per thousand ft^3 of biomethane produced, while capital costs were for the largest plant were \$0.74 per thousand ft^3. In contrast to electricity generation, where the capital costs exceed the operating costs, the operating and maintenance costs for the Swedish plants exceeded capital costs by a significant margin, ranging from \$5.48 to \$7.56 per thousand ft^3. These costs did not include the anaerobic digester.

To estimate the cost of a US biomethane facility that includes an anaerobic digester and a biomethane plant, we combined US costs for anaerobic digestion with Swedish costs for biogas upgrade. The total costs of the combined digester and biomethane plant varied from \$8.44 to \$11.54 per thousand ft^3.

We also estimated the cost of a digester combined with LBM plant that generated its own electricity from some of its biogas and liquefied biomethane from the remainder. We estimate that the plant could produce LBM for \$1.26 per gallon, or 2.10 per diesel gallon equivalent. To these costs must be added the costs of storage and transportation to a fueling station and taxes.

Estimated Costs for Storage and Transport of Biomethane

In addition to the costs of generating biogas and upgrading it to biomethane, a biomethane producer must add the costs of storing and transporting the biomethane. If the biomethane could be put into a pipeline, there would be no storage expense. If the biomethane were purchased by the pipeline owner, there would be no transportation expense. Otherwise these expenses must be paid by the producer or the buyer.

Storage costs vary considerably with the length of time for which the gas must be stored. For example, enough storage capacity to store a day’s worth of CBM produced from a plant that produces 45,000 ft^3 of biomethane per day would add \$100,000 to \$225,000 to the cost of the facility (\$0.60 to \$1.40 per thousand ft^3 of gas) to the cost of the biomethane production.

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. If an 8,000 cow dairy built a dedicated pipeline for \$150,000 per mile, that would add about \$.90 per thousand ft^3 of biomethane to the cost. Trucking requires more on-site storage than piping because enough biomethane must be accumulated to fill a tanker. Other than for LBM, transportation of biomethane by truck costs more per volume than pipeline transport and should be considered as an interim solution.

Summary of Estimated Costs for Dairy Digester and Biomethane Plant

Based on costs for similar, albeit larger, plants in Sweden, as well as discussions with equipment suppliers and other industry personnel, our best estimates for the various capital and operating costs associated with a dairy digester and biogas upgrading plant are as shown below:

Component or Process	**Cost (\$ per 1,000 ft^3) Low Estimate**	**Cost (\$ per 1,000 ft^3) High Estimate**
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

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.

Our estimated costs for producing biogas and upgrading it to biomethane can compete only marginally with today’s natural gas prices. Pioneering plants may have higher costs due to inexperience. At today’s market prices, 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. Added to the cost of production is the cost of storage and transportation.

Costs of Digestion and Upgrade to Biomethane			Current Natural Gas Prices	
Cost Category	Cost ($ per 1,000 ft^3) biomethane Low Est.	High Est.	Price Category	Price ($ per 1,000 ft^3)
Production cost	$8.44	$11.54	Wellhead	$6.05
Storage	$0.00	$2.80	City gate	$7.44
Transportation	$0.00	$0.90	Distribution	$9.84

In contrast, generating electricity from biogas can offset retail electric purchases and can be simpler and more profitable than biomethane production. However, the farmer may produce more electricity than he can use; if this occurs, the farmer cannot be compensated for the excess dairy biogas 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.

Why Support the Development of the Biomethane Industry?

Swedish experience demonstrates that a viable biomethane industry is possible. It is important to note, however, that the economics in Sweden are much more favorable for a biomethane industry than they are in the USA. The most important lesson we learned during our trip to Sweden was that no biomethane plant should be built until a market for the biomethane has been established and a distribution system designed that can move the biomethane to the market.

The current economics for development of the biomethane industry in the USA are challenging if there is no public subsidy. We feel, however, that there are a number of valid reasons to support the development of this industry through publicly funded subsidies, regulation, or tax incentives. Such subsidies and incentives are always necessary to develop a new source of renewable energy or an alternative transportation fuel.

A society that is heavily dependent on fossil fuel energy should be actively developing a wide variety of alternative energy resources. We cannot always predict which technologies will prove the most viable for our future needs. We need to invest in research and development and to build pilot plants for a variety of these technologies. Biomethane production addresses California's commitment to renewable energy and to reducing dependence on imported petroleum. Development of a dairy biomethane industry would help to stimulate California's economy, particularly its rural economy. Biomethane production provides a series of environmental benefits both during the production process and because it can be substituted for fossil fuels. Development of biomethane production technologies and markets today will ensure future preparedness for the growth of this industry should conditions arise that make the production and use of biomethane a more financially viable and/or necessary option.

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.

Considerations for Planning a Biomethane Project

Although there is no magic formula for creating a successful biomethane project, our research indicates that a business plan for a successful biomethane enterprise should demonstrate that the following have been researched and, where possible, completed or obtained:

- Buyer for the biomethane
- Supply of organic waste
- Distribution system—pipeline or storage and subsequent over-the-road transport
- Location for biomethane plant
- Technology and operating plan
- Financial plan
- Permitting and regulatory analysis
- Construction plan

Our research also included a geographic analysis that highlighted the San Joaquin Valley as a focal point for future biomethane projects. By considering factors such as the proximity of dairies to market, existing infrastructure, and regional demand and need, this analysis indicated five promising scenarios that could be further investigated by those interested in developing a biomethane project:

- *Provide fuel to a community vehicle fleet*. A Central Valley community could make a significant environmental contribution by developing an integrated project involving CNG vehicles and a biomethane plant. At least four San Joaquin communities—Tulare, Visalia, Hanford, and Modesto— have both CNG fueling stations and a nearby dense population of dairies. However, the current CNG fleets in these communities are not large enough to support a biomethane plant. An integrated project that increased the number of CNG vehicles on the road and used locally produced CBM would capture a number of environmental and energy security benefits. The first community to do this would be a national showcase.
- *Sell biomethane directly to large industrial customer*. Several areas in the San Joaquin Valley have dairies concentrated near sizable industrial users of natural gas. One or more

of these industrial users could provide a substantial demand for locally produced biomethane, though raw or partially cleaned biogas may suffice in many applications.

- *Distribute biomethane through natural gas pipeline grid*. If the barriers to the use of the natural gas transmission system could be overcome, a biomethane plant could sell directly to the local gas utility, or pay to wheel the biomethane to an industrial or municipal customer on the natural gas grid. The biomethane plant would need to be located along or very close to the distribution line.
- *Build liquefied biomethane plant*. Liquefied biomethane can be used as a direct substitute for LNG. Except for a small pilot project, all LNG vehicle fuel is trucked into California from out-of-state LNG plants. While transportation costs limit a CBM plant to nearby markets, an LBM plant can cost-effectively transport LBM to fueling stations much further away. LBM could also be delivered to liquefied-to-compressed natural gas fueling stations or to customers off the natural gas grid that already receiving gas supplies deliveries in the form of LNG.
- *Use compressed biomethane to generate peak-load electricity*. Because CBM can be stored, a biomethane plant could use its fuel to generate peaking electrical power. Renewable energy that can be dispatched to serve peak demand can earn a substantial premium over non-dispatchable renewable energy resources such as wind and solar.

1. Potential Biogas Supply from California Dairies

Biogas is a product of naturally occurring anaerobic fermentation of biodegradable material. Anaerobic bacteria occur naturally in the environment in anaerobic "niches" such as marshes, sediments, wetlands, and in the digestive tract of ruminants and certain species of insects. These bacteria also exist in landfills where anaerobic decomposition is the principal process degrading landfilled food wastes and other biomass.

When collected or captured, biogas can be used as a renewable energy source similar to natural gas, but with significantly lower methane content and thus a lower heating value. Biogas is derived from renewable biomass sources through a process called anaerobic digestion. Within the USA, the biogas industry is comprised primarily of landfills that collect and utilize landfill gas (LFG) and wastewater treatment plants utilizing anaerobic digesters. Digestion of animal manure from dairies and swine farms is gaining importance in the US both as an energy product and as a means for management of environmental impacts. Currently in the US, biogas is used primarily in engine-generators or boilers for generation of electricity and heat.

This report primarily addresses alternate (non-power and heat generation) uses of biogas produced on dairies, and more specifically, with the production and use of biomethane, an upgraded form of biogas that is equivalent to natural gas. This chapter explores the potential supply of biogas from dairies, including on-farm management factors that affect biogas production. In addition, it discusses the possibility of co-digesting dairy and other biomass wastes—that is, of augmenting dairy wastes with other biomass sources to improve overall biogas yield.

California Dairy Industry

California is the largest dairy state in the nation, with approximately 1.7 million cows on about 2,100 dairies. The average California dairy has about 800 cows, and there is a clear trend toward concentration. According to Western United Dairymen, the number of California dairies decreased from more than 9,700 in 1960 to less than 2,200 in 2003 (Tiffany LaMendola, Western United Dairymen, personal communication, 29 June 2004). This represents a 78% reduction in the number of dairies. Despite the decreasing number of dairies, milk production grew from less than 10 billion pounds a year in 1963 to 35 billion pounds a year in 2003 (CDFA 2004, p. 44). The growth in milk production was generated by a significant increase in production per cow and, due to an increase in the average herd size, to an increase in the total number of cattle in the state.

The continuing trend toward an increased concentration of animals on fewer farms is illustrated in Table 1-1.

Table 1-1 Recent Trends in the California Dairy Industry: More Cows, Fewer Dairies

Year	Average Number of Cows per Dairy	Number of California Dairies
2001	721	2,157
2002	776	2,153
2003	806	2,125

Source: CDFA, 2003a

Table 1-2 Number of Cows in California's Dairies, 2003

County	Number of Cows	Number of Dairies	Average Number of Cows per Dairy
Butte	712	5	142
Del Norte	2,540	10	254
Fresno	90,345	109	829
Glenn	19,398	73	266
Humboldt	16,242	93	175
Kern	98,478	46	2,141
Kings	153,475	155	990
Madera	57,099	56	1,020
Marin	10,145	29	350
Merced	224,734	316	711
Monterey	1,632	4	408
Riverside	82,213	74	1,111
Sacramento	16,247	48	338
San Benito	774	3	258
San Bernardino	152,333	169	901
San Diego	5,500	8	688
San Joaquin	106,162	151	703
Santa Barbara	2,296	3	765
Siskiyou	1,677	5	335
Solano	3,643	5	729
Sonoma	31,192	81	385
Stanislaus	177,432	313	567
Tehama	5,103	23	222
Tulare	437,476	323	1,354
Yolo	2,048	3	683
Yuba	3,302	4	826
Total	1,702,198	2,109	807

Source: CDFA, 2004

Milk produced on California dairies is used in five major dairy product categories: fluid milk; soft products such as sour cream, cottage cheese, and yogurt; frozen products; butter and nonfat dry milk products; and cheese. Cheese is the largest category, using 45% of California's milk production compared to fluid milk, which represents 18% (CDFA 2003a).

Most of California's dairy farms are in the Central Valley. As shown in Table 1-2, Tulare County has the highest number of dairy cows, while Kern County has the largest dairies. Large dairies with 5,000 to 6,000 cows are becoming more commonplace as smaller dairies are consolidated or go out of business.

On-Farm Manure Management and Biogas Supply

California's dairy cows generated 3.6 million bone dry tons (BDT) of manure in 2003 (CBC, 2004). To assess the potential for biogas production from this manure, on-farm waste management techniques need to be considered. The methane-generation potential of the manure is directly affected by the methods used to collect and store manure.

Anaerobic digestion of animal manure, described more fully in Chapter 2, is a readily available technology that is limited by the type of feed a digester can receive. Common digesters use manure that is between 1% and 13% solids. Raw dairy manure contains about 15% total solids, of which about 83% is volatile solids. The percentage of total solids in stored manure depends on how much water the dairy uses to flush the manure. Manure collected fresh has greater methane-generation potential due to the retention of volatile solids. To ensure freshness, animal manure must be collected at least weekly, although daily collection is preferable.

On-Farm Manure Management Systems

In California, manure is collected as a semisolid or solid with a tractor scraper, or as a thin slurry formed by flushing water over a curbed concrete alley where manure is deposited. Typically, one of four prevailing manure management schemes is used on California dairies, depending on dairy housing patterns and manure deposition characteristics:

- Flushed freestall
- Scraped freestall
- Drylot with flushed feedlanes
- Scraped drylot

A *flushed freestall dairy* generally includes a milking barn, a separately roofed freestall barn that usually accommodates only the milk cow herd, and drylots for cow lounging. The milking parlor floor is cleaned by hose or flushed with fresh water. Flushed water containing manure is collected at the end of the flush lane and piped either to a separator or to the storage lagoon.

A *scraped freestall dairy* has the same configuration as a freestall flush dairy, except the freestall lanes are scraped using a skid steer tractor, rubber scraper, mechanical scraper, or vacuum scraper. The manure is typically deposited in a gutter that drains into a central pit. The milking parlor floor is cleaned by hose or flushed with fresh water.

A *flushed drylot dairy* has a milk barn that is flushed as well as drylots with flushed feedlanes. The parlor floor is cleaned by hosing or flushing with fresh water and flushed water containing manure is collected at the end of the flush lane and piped either to a separator or to the storage lagoon. However, a significant portion of the manure is deposited in drylots and scraped at random intervals as solid manure. The solids are often scraped into piles and left until there is an opportunity to haul them away.

Most *scraped drylot dairies* are older dairies. In this system, 85% to 90% of the manure is managed by dry scraping and truck removal. Manure is pushed by a tractor or pulled by a hydraulic scraper to a collection point. Drylot feedlanes usually do not have curbs and are not cleaned by flush water.

RCM Digesters (Berkeley, California; <http://rcmdigesters.com/Default.htm>) estimates that 35% of the cows in California are on flushed freestall dairies, 10% are on scraped freestall dairies, 30% are on flushed feedlane drylot dairies, and 25% are on drylot or scrape dairies (Mark Moser, personal communication, 27 May 2004). Many farms use a combination of these manure management systems, but in general most farms in northern California and the Central Valley use flush water and store manure in lagoons, while most Southern California dairies scrape their manure. The farmer chooses between these systems based on the price and availability of water as well as on local regulations and the amount of available land. In some jurisdictions the farmer is obligated to remove the dairy manure from the farm if there is inadequate acreage on which to spread it.

Biogas Production Potential from California Dairies

The quantity of biogas created from the digestion of dairy manure is determined by the dairy's manure management system. Key considerations for biogas production include the freshness and concentration of digestible materials in the manure. In theory, flushed manure collection systems produce less gas than regularly scraped manure systems because the digestible materials are dispersed and diluted. However, if collection of scraped manure is infrequent—which it typically is—the manure in scraped drylots may decompose and become unusable for anaerobic digestion. Dirt lot scraping incorporates dirt and stones into the scraped manure, and these may damage equipment and accumulate in a digester. Manure scraped from concrete surfaces on dirt lots will also include large quantities of inorganics, although manure scraped from freestall barns where cows remain inside is typically relatively clean, unless the bedding is sand or wood chips. Sand tends to collect within the digester and reduce the active volume of the digester over time; sawdust used as bedding passes through the digester untreated; and paper bedding increases gas yield. In practical experience, therefore, because of the infrequency of collection and the incorporation of inorganics into the manure, scraped drylot dairies are usually not good candidates for biogas production.

Storage of manure also affects biogas production potential. Drylot storage techniques produce very little biogas because aerobic conditions inhibit the development of the methanogenic bacteria that create biogas. Manure stored in lagoons produces a substantial quantity of methane-rich biogas. If the lagoons are uncovered, this biogas is released into the atmosphere. When the waste is very dilute, solids tend to sink and create a layer of sludge in the bottom of lagoons or float and create a crust. For this reason, many dairies have solids separators to reduce solids loading in storage lagoons. Typical mechanical separators recover 15% to 20% of the solids from manure, while gravity separation may recover up to 40% of the solids. Separation of the solids results in the reduction of volatile solids in the lagoons and a roughly 25% lower methane yield.

Table 1-3 presents the potential daily methane (CH_4) production from California dairies using existing technology and practices. The amount that is produced depends primarily on the quality of the feed for the cows and the manure collection system used. The use of screen separators, which is assumed in the table, tends to reduce methane production by 25%.

Table 1-3 Potential Daily Methane Production from California Dairies [a]

Type of Dairies	Number of Cows	Potential Daily Methane Production [b] (ft^3/d)	
		Per Cow [c]	**In California**
Flushed freestall	595,769	32.2	19,183,771
Scraped freestall	170,220	32.2	5,481,084
Flushed drylot	510,659	23.8	12,153,691
Scraped drylot [d]	425,550	5.6	2,383,080
Totals	1,702,198		39,201,626

ft^3/d = Cubic feet per day

[a] Updated from (CEC 1997).

[b] Assuming screen solids separators are used, which reduces methane production by 25%.

[c] Note that an average of 30 ft^3/day/cow is used elsewhere in this report; this figure reflects the practical consideration that most of the biogas potential will come from freestall rather than drylot dairies because manure management on these dairies is more conducive to biogas generation.

[d] Although scraped drylot dairies have the potential to generate biogas, most are not good candidates because of infrequent manure collection and storage techniques.

Based on the information presented in Table 1-3, we estimate that California dairies have a methane production potential of about 40 million cubic feet per day (ft^3/d) or 14.6 billion cubic feet per year (ft^3/y). Using the early 2005 delivered price of natural gas (about $10.00 per thousand cubic feet), this is equivalent to over $146 million per year in energy costs.[1] In terms of electricity output, this corresponds to over 1.2 million megawatt-hours (MWh) of energy or about 140 MW of electricity (MW_e). As new technologies are tried and proven the methane yield and electrical production per cow is likely to increase.

Co-Digestion of Dairy and Other Wastes

To augment methane production, manure from dairy cows can be co-digested with additional substrates such as agricultural residues and food-processing waste. Table 1-4 shows the potential methane-generation potential of various biomass sources available in California. The data used to estimate methane potential for these wastes was derived from an early study by Buswell and Hatfield of the Illinois Water Survey (1936); this study is still the most comprehensive information from a single study on the digestion of various waste resources.

Both gross and technical methane potentials are presented in Table 1-4. The gross potential represents the methane potential of all the waste generated within the stated categories in the state. The portion that is technically available is based on evaluations by the author and the various references cited.

The gross potential of swine and poultry layer manure in California is 30,000 and 274,000 BDT, respectively. Of this amount, about half is available for anaerobic digestion (technical potential). This amounts to about 160 million ft^3/yr of CH_4 from swine operations (ASAE, 1990, p. 464), and about 850 million ft^3/yr of CH_4 for poultry layer operations (RCM Digesters, 1985). Swine and poultry farms lend themselves to biogas generation due to the regular collection of manure, and were therefore included in Table 1-4. Manure from cattle feedlot and poultry broiler and turkey operations were not considered to be technically available due to the infrequent collection of manure at these facilities.

Crop Residues

The 2003 California Biomass Resource Assessment (CBC, 2004) indicates that the gross potential of waste available from vegetable production in 2003 was 1.2 million BDT. Of this amount, only 100,000 BDT of biomass are estimated to be “technically” available on an annual basis. This waste would have the potential to generate about 1 billion ft^3 of CH_4 per year (Buswell and Hatfield, 1936, p. 170). The CBC assessment (2004) also states that the gross potential for biomass from field and seed production is about 5 million BDT. The main components are rice

[1] This figure will vary according to the actual price of natural gas. At the time of final manuscript preparation (spring 2005), this price is historically high at around $10 per therm; in the recent past, the price has been between $6 and $7 per therm.

straw (1.5 million BDT), cotton residue, wheat straw, and corn stover (leaves and stalks of corn). About 2.4 million BDT of this is potentially available for anaerobic digestion. As shown in Table 1-4, this 2.4 million BDT of biomass has the potential to generate 5.2 billion ft^3 of CH_4 per year (Buswell and Hatfield, 1936, p. 114) recoverable using existing collection methods. Though not considered in Table 1.4, recent research on rice straw indicates that the 1.5 million BDT of rice straw that is potentially available could produce as much as 6 billion ft^3 of CH_4 per year (Zhang, 1998).

Figures for orchard and vine production biomass wastes are also provided (CBC, 2004); however, these biomass sources were not included in Table 1-4 because the woody nature of the biomass generated in these farming operations does not lend itself to anaerobic digestion. It should be noted that all the crop residues mentioned are relatively undigestible without pretreatment such as screening (to remove dirt) and size reduction, and present significant handling issues for anaerobic digestion. Thus, although they represent a potentially large biomass resource, crop residues may not be a practical source of material for co-digestion with dairy wastes.

Food Processing Waste

The League of California Food Processors estimates that 14 to 16 million tons of fruits and vegetables are processed in California every year by canners, freezers, dryers, and dehydrators (Ed Yates, personal communication, 17 May 2004). These operations generate 1 million tons of waste annually from July through September. The waste material consists of peeled material, core material, culls and extraneous leaves and is 5% to 8% total solids. According to Yates, 49% of the waste is used as cattle feed and another 49% is used as soil amendment (personal communication, 17 May 2004). The 490,000 wet tons of waste material used annually as soil amendment could potentially be available for anaerobic digestion. The technical CH_4 generation potential from this waste would be 359 million ft^3/yr (Buswell and Hatfield, 1936, p. 170). If the material fed to cattle was also used to generate gas, the gross potential is double this amount. However, using these food wastes as cattle feed is a higher value use than using them as a biomass source for gas generation. Also, the seasonal availability of food processing wastes could be problematic (e.g., grape and apple harvests occur over a 60-day period).

The California Milk Advisory Board indicates there are 60 cheese manufacturing plants that produced 1.8 billion pounds of cheese in 2003 (<www.realcaliforniacheese.com>, 17 May 2004). According to Carl Morris, general manager of Joseph Gallo Farms, for every pound of cheese produced, approximately 9 pounds of whey is generated (personal communication, 18 May 2004). The whey is typically converted into a powdered product and sold. However, 4.6% of the whey is in the form of lactose permeate, a waste product with a total solids content of 6%. Based on this, approximately 23,700 tons of lactose-permeate solids waste was generated in 2003 by California’s cheese industry. This waste stream is both continuous and highly digestible, and could easily be combined with dairy wastes. Using Buswell and Hatfield's data (1936, p. 170), lactose permeate waste has the potential to generate 250 million ft^3 of CH_4 per year.

Slaughterhouse Waste and Rendering Plant Wastewater

The 2003 California Biomass Resource Assessment conducted by the California Biomass Collaborative indicates that there are 79,000 BDT of slaughterhouse waste produced annually in the state, of which approximately 63,600 BDT would be technically available for anaerobic digestion. This waste, which includes digestible solids as well as liquids, is continuous and highly digestible and could generate approximately 660 million ft^3 of CH_4 per year (Buswell and Hatfield, 1936, p.155).

Table 1-4 Potential Methane Generation from Biomass Sources, California

Biomass Waste Material	Annual Methane Production [a] (million ft^3/y) Gross Methane Potential	Technical Methane Potential
Swine manure [b]	320	160
Poultry layer manure [c]	1,700	850
Poultry broiler manure [d]	1,800	0
Turkey manure [d]	1,300	0
Dairy manure	21,100	14,300
Cattle feedlot manure [d]	4,100	0
Crop residues	10,700	5,220
Vegetable residue	11,300	940
Meat processing	660	530
Rendering (wastewater) [e]	120	120
Cheese whey (lactose permeate)	250	250
Food processing waste	720	360
Processed green waste [f]	18,000	0
Landfilled manure [f]	220	0
Landfilled composite organic waste	15,200	0
Landfilled food waste [f]	19,900	0
Landfilled green waste [f]	16,500	0
Total	123,890	22,730

ft^3/y = Cubic feet per year
[a] Unless otherwise indicated, these figures calculated based on Buswell and Hatfield data (1936).
[b] ASAE, 1990, p. 464.
[c] RCM Digesters, 1985.
[d] CBC, 2004 amended by personal communication from R. Williams, June 29, 2005.
[e] Metcalf & Eddy, 1979, p. 614; US EPA, 1975, p. 61.
[f] Al Seadi, Undated.

According to the California Integrated Waste Management Board (<http://www.ciwmb.ca.gov/FoodWaste/Render.htm>, 26 May 2004), there are 21 rendering operations in California. Waste from these plants amounts to approximately 2.45 million gallons per day (gpd) of high-strength organic wastewater (Fred Wellen, Baker Commodities, Inc., personal communication, 26 May 2004). The waste is typically treated in open lagoons to reduce the biological oxygen demand (BOD) prior to release to sewage treatment facilities or land application. This wastewater is highly digestible and could potentially be digested at the plant or co-digested with manure, especially if the rendering operations are in close proximity to the dairy. Rendering plant waste has the potential to generate 120 million ft^3 of CH_4 per year (US EPA, 1975, pp. 61, 87).

Green Waste from Municipal/Commercial Collection Programs

According to a June 2001 report entitled *Assessment of California's Compost and Mulch Producing Infrastructure*, composters and processors in California process over 6 million tons of organic materials per year (CIWMB, 2001). From this raw material, about 15 million cubic yards of organic material products are produced, including compost, boiler fuel, mulch and various blends (CIWMB, 2001). Although this material, unprocessed, is generally not suitable for anaerobic digestion because of its high lignin and low digestibles content, Sweden and other European countries digest significant portions of this waste stream. The presence of pesticides, fertilizer, wood chips, and other debris in domestic greenwaste adds further complexity. If these problems can be surmounted greenwaste could substantially augment the production of dairy biogas. The Inland Empire Utilities Agency is now in the planning stages for building such a system using dairy waste and local greenwaste. The California Energy Commission has provided funding to build a research digester designed by Dr. Ruihong Zhang of University of California Davis that will utilize greenwaste.

Conclusions Regarding Co-Digestion

The gross and technical potential for methane generation from biodegradable wastes in California, including dairy wastes and landfilled wastes, is summarized in Table 1-4. The total gross potential is about 124 billion ft^3 CH_4/year, enough gas to produce about 10.4 million megawatt-hours (MWh) of electricity or about 1,200 MW of electrical capacity (at a heat rate of 12,000 Btu/kWh, assuming an energy conversion factor of 28%). However, most of this waste is not technically available due to inefficiencies in collection, contamination with other waste products, and other uses. Therefore the technical potential is estimated at only 23 billion ft^3 of CH_4/year, or about 220 MW_e, with dairy manures representing about two thirds of this amount. To put these figures in perspective, the total statewide demand for natural gas is about 6 billion ft^3/day, or 2,200 billion ft^3/year.

For co-digestion with dairy manures, only a relatively small fraction of potential or even technically available wastes would actually be usable, due to the many constraints on co-digestion, which range from location to seasonal availability to process constraints. Most importantly, only a few waste resources (whey, meat processing, rendering, fruit and vegetable processing) lend themselves to co-digestion without introducing major difficulties (e.g., pretreatment). Although co-digestion may be important on a site-specific basis, on a statewide basis we do not expect that co-digestion of other biomass wastes would augment the dairy waste methane potential shown in Table 1-2 by more than 10% to 20%.

2. Production of Biogas by Anaerobic Digestion

Anaerobic digestion is a natural process in which bacteria convert organic materials into biogas. It occurs in marshes and wetlands, and in the digestive tract of ruminants. The bacteria are also active in landfills where they are the principal process degrading landfilled food wastes and other biomass. Biogas can be collected and used as a potential energy resource. The process occurs in an anaerobic (oxygen-free) environment through the activities of acid- and methane-forming bacteria that break down the organic material and produce methane (CH_4) and carbon dioxide (CO_2) in a gaseous form known as biogas.

Dairy manure waste consists of feed and water that has already passed through the anaerobic digestion process in the stomach of a cow, mixed with some waste feed and, possibly, flush water. The environmental advantages of using anaerobic digestion for dairy farm wastes include the reduction of odors, flies, and pathogens as well as decreasing greenhouse gas (GHG) and other undesirable air emissions. It also stabilizes the manure and reduces BOD. As large dairies become more common, the pollution potential of these operations, if not properly managed, also increases. The potential for the leaching of nitrates into groundwater, the potential release of nitrates and pathogens into surface waters, and the emission of odors from storage lagoons is significantly reduced with the use of anaerobic digestion. There may also be a reduction in the level of VOC emissions.

Elements of Anaerobic Digestion Systems

Anaerobic digester systems have been used for decades at municipal wastewater facilities, and more recently, have been used to process industrial and agricultural wastes (Burke, 2001). These systems are designed to optimize the growth of the methane-forming (*methanogenic*) bacteria that generate CH_4. Typically, using organic wastes as the major input, the systems produce biogas that contains 55% to 70% CH_4 and 30% to 45% CO_2. On dairy farms, the overall process includes the following:

- *Manure collection and handling*. Key considerations in the system design include the amount of water and inorganic solids that mix with manure during collection and handling, as described in Chapter 1.
- *Pretreatment*. Collected manure may undergo pretreatment prior to introduction in an anaerobic digester. Pretreatment—which may include screening, grit removal, mixing, and/or flow equalization—is used to adjust the manure or slurry water content to meet process requirements of the selected digestion technology. A concrete or metal collection/mix tank may be used to accumulate manure, process water and/or flush water. Proper design of a mix tank prior to the digester can limit the introduction of sand and rocks into the anaerobic digester itself. If the digestion processes requires a thick manure slurry, a mix tank serves a control point where water can be added to dry manure or dry manure can be added to dilute manure. If the digester is designed to handle manures

mixed with flush and process water, the contents of the collection/mix tank can be pumped directly to a solids separator. A variety of solids separators, including static and shaking screens are available and currently used on farms.

- *Anaerobic digestion*. An anaerobic digester is an engineered containment vessel designed to exclude air and promote the growth of methane bacteria. The digester may be a tank, a covered lagoon (Figure 2-1), or a more complex design, such as a tank provided with internal baffles or with surfaces for attached bacterial growth. It may be designed to heat or mix the organic material. Manure characteristics and collection technique determine the type of anaerobic digestion technology used. Some technologies may include the removal of impurities such as hydrogen sulfide (H_2S), which is highly corrosive.

- *By-product recovery and effluent use*. It is possible to recover digested fiber from the effluent of some dairy manure digesters. This material can then be used for cattle bedding or sold as a soil amendment. Most of the *ruminant* and hog manure solids that pass through a separator will digest in a covered lagoon, leaving no valuable recoverable by-product.

- *Biogas recovery*. Biogas formed in the anaerobic digester bubbles to the surface and may accumulate beneath a fixed rigid top, a flexible inflatable top, or a floating cover, depending on the type of digester. (Digesters can also include integral low-pressure gas storage capability, as described in Chapter 4.) The collection system, typically plastic piping, then directs the biogas to gas handling subsystems.

- *Biogas handling*. Biogas is usually pumped or compressed to the operating pressure required by specific applications and then metered to the gas use equipment. Prior to this, biogas may be processed to remove moisture, H_2S, and CO_2, the main contaminants in dairy biogas, in which case the biogas becomes *biomethane* (see Chapter 3). (Partial removal of contaminants, particularly H_2S, will yield an intermediate product that we refer to in this report as *partially upgraded* biogas). Depending on applications, biogas may be stored either before or after processing, at low or high pressures (see Chapter 4).

- *Biogas use*. Recovered biogas can be used directly as fuel for heating or it can be combusted in an engine to generate electricity or flared. If the biogas is upgraded to biomethane, additional uses may be possible (see Chapter 5).

Anaerobic digestion is a complex process that involves two stages, as shown in the simplified schematic in Figure 2-2. In the first stage, decomposition is performed by fast-growing, acid-forming (*acidogenic*) bacteria. Protein, carbohydrate, cellulose, and hemicellulose in the manure are hydrolyzed and metabolized into mainly short-chain fatty acids—acetic, propionic, and butyric—along with CO_2 and hydrogen (H_2) gases. At this stage the decomposition products have noticeable, disagreeable, effusive odors from the organic acids, H_2S, and other metabolic products.

Figure 2-1 A dairy farm anaerobic digestion system (RCM, Inc., Berkeley, California)

In the second stage, most of the organic acids and all of the H_2 are metabolized by methanogenic bacteria, with the end result being production of a mixture of approximately 55% to 70% CH_4 and 30% to 45% CO_2, called biogas. The methanogenic bacteria are slower growing and more environmentally sensitive (to pH, air, and temperatures) than the acidogenic bacteria. Typically, the methanogenic bacteria require a narrow pH range (above 6), adequate time (typically more than 15 days), and temperatures at or above 70° F, to most effectively convert organic acids into biogas. The average amount of time manure remains in a digester is called the *hydraulic retention time*, defined as the digester volume divided by daily influent volume and expressed in days.

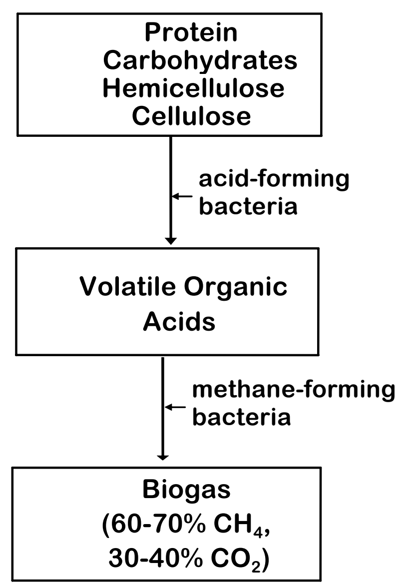

Figure 2-2 Simplified process of biogas production

A more complete discussion of the anaerobic digestion process can be found in Appendix A.

Anaerobic Digestion Technologies Suitable for Dairy Manure

Numerous configurations of anaerobic digesters have been developed, but many are not likely to be commercially applicable for California dairy farms. This section briefly describes the three digester types most suitable for California dairies: ambient-temperature covered-lagoon, complete-mix, and plug-flow digesters. Table 2-1 provides the operating characteristics of these manure digester technologies. More detail about these technologies is provided in Appendix B.

Table 2-1 Characteristics of Anaerobic Digesters Suitable for On-Farm Use

Digester Type	Technology Level	Concentration of Influent Solids (%)	Allowable Solids Size	Supplemental Heat Needed?	HRT [a] (days)
Ambient-temperature covered lagoon	low	0.1 – 2	fine	no	40+
Complete mix	medium	2.0 – 10	coarse	yes	15+
Plug flow	low	11.0 – 13	coarse	yes	15+

[a] HRT = Hydraulic Retention Time = digester volume/daily influent volume

Ambient-Temperature Covered Lagoon

Properly designed anaerobic lagoons are used to produce biogas from dilute wastes with less than 2% total solids (98% moisture) such as flushed dairy manure, dairy parlor wash water, and flushed hog manure. The lagoons are not heated and the lagoon temperature and biogas production varies with ambient temperatures. Coarse solids such as hay and silage fibers in cow manure must be separated in a pretreatment step and kept out of the lagoon. If dairy solids are not separated, they float to the top and form a crust. The crust will thicken, which will result in reduced biogas production and, eventually, infilling of the lagoon with solids.

Unheated, unmixed anaerobic lagoons have been successfully fitted with floating covers for biogas recovery for dairy and hog waste in California. Other industrial and dairy covered lagoons are located across the southern USA in warm climates. Ambient temperature lagoons are not suitable for colder climates such as those encountered in New York or Wisconsin.

Complete-Mix Digester

Complete-mix digesters are the most flexible of all digesters as far as the variety of wastes that can be accommodated. Wastes with 2% to 10% solids are pumped into the digester and the digester contents are continuously or intermittently mixed to prevent separation. Complete-mix digesters are usually aboveground, heated, insulated round tanks. Mixing can be accomplished by gas recirculation, mechanical propellers, or circulation of liquid.

Plug-Flow Digester

Plug-flow digesters are used to digest thick wastes (11% to 13% solids) from ruminant animals. Coarse solids in ruminant manure form a viscous material and limit solids separation. If the waste is less than 10% solids, a plug-flow digester is not suitable. If the collected manure is too dry, water or a liquid organic waste such as cheese whey can be added.

Plug-flow digesters consist of unmixed, heated rectangular tanks that function by horizontally displacing old material with new material. The new material is usually pumped in, displacing an equal portion of old material, which is pushed out the other end of the digester.

Factors Influencing Anaerobic Digestion Efficiency

Digesters can function at ambient temperatures in warmer climates such as California, but with a lower biogas output than heated digesters. In some applications and in colder environments, digesters are heated. The optimal ranges for anaerobic digestion are between 125 to 135° F (*thermophilic* conditions) and between 95 to 105° F (*mesophilic* conditions). Anaerobic digestion under thermophilic conditions generates gas in a shorter amount of time than anaerobic digestion under mesophilic conditions. However, a higher percentage of the gross energy generated is required to maintain thermophilic conditions within the reactor. The extra heat is either extracted from the gross waste heat recovery in an engine or recovered from effluent.

Covered lagoons have seasonal variation in gas production due to the variation in ambient temperature. Gas production from complete-mix and plug-flow digesters are impacted less by ambient temperature variation since they are usually heated. On an annual basis, gas production from complete-mix and plug-flow digesters tends to be higher than for ambient-temperature covered lagoons because a higher percentage of solids entering complete-mix and plug-flow digesters is converted to biogas and the higher operating temperatures favor greater microbial activity. Gas production in all these digesters is dependent on hydraulic retention time.

Table 2-2 Modeled Comparison of Biogas Generation Potential of Three Different Anaerobic Digestion Processes on Typical 1,000-Cow Dairy Merced, CA Dairy [a]

Month	Biogas Generation (1,000 ft^3)		
	Covered Lagoon	**Plug Flow**	**Complete Mix**
January	949	1,713	1,713
February	1,096	1,547	1,547
March	1,358	1,713	1,713
April	1,383	1,658	1,658
May	1,488	1,713	1,713
June	1,544	1,658	1,658
July	1,648	1,713	1,713
August	1,634	1,713	1,713
September	1,532	1,658	1,658
October	1,475	1,713	1,713
November	1,323	1,658	1,658
December	1,003	1,713	1,713
Total Annual	16,430	20,172	20,172

[a] Modeled using US EPA AgStar Farmware program

A comparison of the biogas potential of the three main types of digesters for use on dairy farms was made by the US EPA (see AgStar website <http://www.epa.gov/agstar/>). The US EPA's Farmware program was run for a 1,000-milking-cow freestall dairy operated in Merced, California. The program was run under three different digester configurations: covered lagoon, plug flow, and complete mix. For the covered lagoon configuration, US EPA chose a manure management scheme in which all areas of the dairy were flushed and all dairy wastes ended up in the lagoon. To meet the higher total solids requirement of the plug-flow and the complete-mix designs, the chosen manure management option involved flushing the parlor area and scraping all other areas of the dairy. The results of biogas production in a typical year are shown in Table 2-2.

The results indicated that the plug-flow and the complete-mix digesters have the same gas production; however, the cost of a complete-mix digester is higher than a plug-flow system. A complete-mix digester must be larger than a plug-flow to accommodate the additional water added to reduce the total solids concentration of the influent. The gas output from the covered lagoon was significantly less than from the plug-flow and complete-mix digesters (especially in the winter months) because it was not heated and therefore had suboptimal conditions for gas production.

Environmental Impacts of Anaerobic Digestion

The environmental impacts of on-farm anaerobic digestion depend on the manure management system that the digester amends or replaces as well as the actual use of the biogas produced. Typically, the anaerobic digestion of dairy manure followed by flaring of biogas, combustion of biogas for electricity, or production and use of biomethane as fuel can provide a number of direct environmental benefits. These include:

- Reduced GHG emissions
- Potential reduction of VOC emissions
- Odor control
- Pathogen and weed seed control
- Improved water quality

One potentially negative environmental impact of anaerobic digesters that combust the biogas is the creation of nitrogen oxides (NO_x), which are regulated air pollutants and an ozone precursor. Nitrogen oxides are created by combustion of fuel with air. Combustion of dairy biogas or any other methane containing gas (whether in a flare, reciprocating or gas turbine engine, or a boiler) will emit NO_x. The emission rate varies but is generally lowest for properly engineered flares and highest for rich burn reciprocating (piston) engines. NO_x emissions are controlled by using lean burn engines, catalytic controls or microturbines. The latter two methods are fouled by the high sulfur content of biogas, and the H_2S must be scrubbed to prevent the swift corrosion of these devices.

Reduced Greenhouse Gas Emissions

The use of anaerobic digestion to create biogas from dairy manure can reduce GHG emissions in two distinct ways. First, when used in combination with a manure management system that stores manure under anaerobic conditions, it can prevent the release of CH_4, a greenhouse gas, into the atmosphere. Second, the biogas or biomethane generated by the anaerobic digestion process can replace the use of fossil fuels that generate GHGs.

The biogas generated from anaerobic digestion contains about 60% CH_4. It is this component, methane (which is also the main component of natural gas), that can produce energy. In addition to being an energy resource, however, CH_4 is also a GHG with 21 times the global warming potential, by weight, of CO_2. Globally, CH_4 constitutes 22% of anthropogenic GHG emissions in terms of carbon equivalents. In the USA, CH_4 contributes 10% of anthropogenic GHG emissions and 10% of the CH_4 is derived from animal manure (US DOE, 1999b, pp. 6, 13-14). Thus animal manure produces approximately 1% of all anthropogenic GHG emissions in the USA.

Most of the Central Valley dairies store manure in large lagoons under anaerobic conditions. Manure stored in anaerobic conditions produces the bulk of the GHG emissions from animal waste. The methanogenic bacteria that thrive in this environment produce CH_4, which is released into the atmosphere. If the lagoon is covered or the manure is digested in another type of digester, the CH_4 can be captured and combusted. This destroys the CH_4 and releases CO_2. Since each unit of CH_4 has 21 times the global warming potential of CO_2, 21 units of GHG are eliminated and 1 unit is created for each unit of CH_4 that is captured and combusted, creating an overall net gain of 20 units. This benefit will occur as long as the methane is combusted—whether the biogas is flared, used to generate electricity, or upgraded to biomethane and then combusted to produce energy. This benefit is in addition to the benefit when energy created by this renewable fuel replaces energy created by combusting a fossil fuel.

A good proportion of dairy manure in Southern California is stored aerobically. Methanogenic bacteria do not thrive in aerobic conditions and thus manure that is stored in corrals or piles where it is exposed to the air produces very little CH_4 (US EPA, 1999, p 7.4-15). Since manure stored in this manner releases little CH_4, putting it into an anaerobic digester produces no significant reduction in CH_4 emissions, although there may be some nitrous oxide (N_2O) reductions. Also, if the anaerobic digester has any significant leakage, emissions of CH_4 may actually be higher than they would be using aerobic (dry) storage alone.

Reduced Volatile Organic Compound Emissions

Volatile organic compounds, in combination with NO_x and sunlight, produce ozone, the primary element in smog and a criteria air pollutant. Thus VOCs are an ozone precursor and are regulated by State and federal law. In California, VOCs are often called reactive organic gases (ROG).

VOCs are an intermediate product generated by methanogenic bacteria during the transformation of manure into biogas. It is expected that the total volume of VOCs generated is related to the total volume of CH_4 produced, but the more effective the methanogenic decomposition, the lower the VOCs as a percentage of the biogas. VOCs are created by enteric fermentation (the digestion process of the cow) and released primarily through the breath of the cow. They are also produced by the anaerobic decomposition of manure. A well designed and managed anaerobic digester may reduce VOCs by more completely transforming them into CH_4. Some fraction of the remaining VOCs in the biogas should be eliminated through the combustion of the biogas.

For its emission inventory, the California Air Resources Board (CARB) uses an emission factor for dairy cows of 12.8 lb of VOCs per cow per year. (This emission factor is based on a single 1938 study, which measured CH_4 emissions from a cow but did not measure VOC emissions.) Based on this emission factor, dairies are a significant source of VOC emissions and a major contributor to ozone in the San Joaquin Valley. The CARB has not determined the portion of VOC emissions that is generated by manure-holding lagoons.

Current law, notably Senate Bill 700 (SB 700), requires California air districts to regulate dairies in accordance with the federal Clean Air Act. Since the San Joaquin Valley and the South Coast are extreme non-attainment areas for ozone (see <http://www.valleyair.org/General_info/faq_frame.htm>), major sources of pollution in those air districts need to control their VOC emissions. The San Joaquin Valley Air Pollution Control District has proposed that anaerobic digesters be required for new dairies that have more than 1,984 cows as a “best available control technology” (BACT) for ROGs (SJVAPCD, 2004). The South Coast Air Quality Management District (which covers the Los Angeles Basin) is reviewing the anaerobic digestion technology under its Proposed Rule 1127 (see <http://www.aqmd.gov/rules/reg/reg11/r1127.pdf>).

Now that dairies are being regulated for VOC emissions, air districts and other regulators recognize the importance of providing a better VOC emission factor. The CARB, the San Joaquin Air Pollution Control District, the US EPA Region IX, the US Department of Agriculture (USDA), and the State Water Board have initiated and funded several studies, mostly led by researchers from University of California Davis and California State University Fresno. The research is aimed at determining an emission factor for VOCs from California cows. Preliminary results indicate that most of the VOCs on the dairy come from enteric fermentation and from feed, with a smaller proportion from lagoons.

Increased Nitrogen Oxide Emissions

When biogas or any fuel is combusted in an internal combustion engine it produces NO_x, a criteria air pollutant as well as a precursor to ozone and smog.

For reciprocating engines the main NO_x production route is thermal, and is strongly temperature dependent. Internal combustion engines can produce a significant amount of NO_x. Maximum NO_x formation occurs when the fuel mixture is slightly lean, i.e. when there is not quite enough oxygen to burn all the fuel. Lean-burn engines typically have lower NO_x formation than stoichiometric or rich-burn engines because more air dilutes the combustion gases, keeping peak flame temperature lower. Gas turbines and microturbines also produce a very low level of NO_x because peak flame temperatures are low compared to reciprocating engines. A system to flare gas, if properly engineered, will generate a substantially lower level of NO_x than an uncontrolled reciprocating engine.

Dairy anaerobic digesters that burn biogas for electricity typically use reciprocating internal combustion engines; microturbines have not been used successfully because impurities in the biogas corrode the engines. When there is enough biogas to support a lean-burn engine, NO_x can be kept relatively low. The Inland Empire Utility Agency in Chino, California uses 700 to 1,400 kilowatt (kW) engines to combust biogas and has kept NO_x production below 50 ppm (Clifton, 2004), which meets BACT for waste gas as proposed by CARB in its guidance document to California air districts as required under SB 1298 (CARB, 2002, p.4). For smaller applications (capacity of less than 350 kW), there are no lean-burn waste-gas reciprocating engines available in the USA; consequently, NO_x formation at these facilities can be expected to be much higher.

There are several catalytic conversion technologies for reducing NO_x emissions which can be used on rich- and lean-burn engines that use natural gas, but the impurities in dairy biogas will substantially shorten the life of the catalytic NO_x controls. If the H_2S content of the biogas is reduced to a very low level before introduction to the engine, the emissions from the scrubbed dairy biogas will not degrade catalytic controls or microturbines as quickly. One California dairy has installed a H_2S scrubbing system and a catalytic emission control device on its engine. Initial tests are promising, but it is too soon to know if this will be a reliable solution. The current status of air district regulation of NO_x emissions will be discussed in Chapter 6.

If biogas is upgraded to biomethane, the selective catalytic reduction technologies used for natural gas engines can be used to keep NO_x formation at acceptable levels. Biomethane will not corrode microturbines and electricity generated in microturbines from biomethane has a very low accompanying NO_x formation.

Control of Unpleasant Odors

According to anecdotal reports, most of the approximately 100 anaerobic digesters processing animal manure in the USA were built to address odor complaints from neighbors. As more housing is built in formerly rural areas of California's Central Valley, complaints about odors from dairies increase. Most of the odor problem comes from H_2S, VOC, and ammonia (NH_3-N) emissions from dairy manure. While hard to measure objectively, these odors are perceived as a serious environmental problem by residents in proximity to dairy farms. Fortunately, anaerobic digestion is a good method for controlling these odors, particularly if used in conjunction with a system that will scrub the H_2S from the biogas.

Control of Pathogens and Weed Seeds

Digesters that are heated to mesophilic and thermophilic levels are very effective in denaturing weed seeds and reducing pathogens. Pathogen reduction is greater than 99% in a 20-day hydraulic retention time, mesophilic digester. Thermophilic temperatures essentially result in the complete elimination of pathogens. Covered-lagoon digesters, which operate at ambient temperatures, have a more modest effect on weed seeds and pathogens.

Improved Water Quality

An anaerobic digester will have minimal effect on the total nutrient content of the digested manure. However, the chemical form of some of the nutrients will be changed. A digester decomposes organic materials, converting approximately half or more of the organic nitrogen (org-N) into NH_3-N. Some phosphorus (P) and potassium (K) are released into solution by decomposing material. A minimal amount of the P and K will settle as sludge in plug flow and complete mix digesters. However 30% to 40% of the P and K are retained in covered-lagoon digesters in the accumulated sludge. Dissolved and suspended nutrients are of lesser concern as they will flow through the digester.

The anaerobic digestion process is an effective way to reduce high BOD in the effluent. Biological oxygen demand is a measure of the amount of oxygen used by microorganisms in the biochemical oxidation of organic matter; BOD concentrations in dairy wastewater are often 25 to 40 times greater than those in domestic wastewater. Anaerobic processes can remove 70% to 90% of the BOD in high-strength wastewater at a lower cost, in terms of both land and energy inputs, than aerated systems.

Motivation for Realizing Environmental Benefits on Dairy Farms

Many of the environmental benefits discussed above also can be realized by capturing the biogas produced at a dairy and flaring it. In fact, flaring typically produces less NO_x than combustion of the biogas for generating electricity. Federal and state law require large landfills to flare their *landfill gas* (similar in composition to dairy biogas) to reduce VOC emissions and the danger of explosions. As a result of SB 700, the San Joaquin Air Pollution Control District proposed to require digesters as BACT for new or modified dairies with more than 1,954 head of cattle, although the proposal has since been withdrawn as a result of a lawsuit. At this time, the major motivations for smaller dairies to combust or capture/flare the CH_4 produced on-site are likely to be economic or as a means of odor control.

Whether used to generate electricity, or upgraded to biomethane and used for vehicular or engine fuel, biogas is a renewable energy product. Like other renewable energy sources, such as solar and wind-generated power, biogas can be substituted for greenhouse-gas-emitting fossil fuels, producing a net decrease in GHG emissions. On those dairy farms where manure is stored under anaerobic conditions (i.e., where it is not stored in piles that decompose aerobically over time), there is an added benefit. Using biogas as a fuel results in the reduction of CH_4 emissions that would otherwise be released into the atmosphere (e.g., through storage in uncovered lagoons).

However, without financial or regulatory motivations, farmers will have little motivation to capture and use dairy biogas.

Increasing the Methane Content of Biogas

There are several technologies that have been used to increase methane generation and extraction at landfills and wastewater treatment plants; conceivably, these techniques could also be applied to dairy wastes. Possible techniques include pretreatment of the feedstock with heat, ultrasonic devices, or impact grinding (all to increase the degree of hydrolysis of the feedstock); microbial stimulants; or co-digestion with other wastes.

Pretreatment Techniques

Thermal pretreatment can increase the CH_4 yield of certain substrates. However, it is not an effective pretreatment technique for the anaerobic digestion of all substrates. For example, Ferrer et al. found that thermal pretreatment at 80^{o}C (176^{o} F) did not enhance the anaerobic digestion of water hyacinth because water hyacinth's solubility increased only slightly under the tested conditions (2004, pp 2107-2109). In contrast, the pasteurization of slaughterhouse waste at the Upsalla biogas plant in Sweden resulted in a reported fourfold increase in CH_4 yields after thermal treatment at 70^{o}C (158^{o} F) for 1 hour (Norberg, 2004). However, the effects of this treatment method on high-lipid and protein waste have not been adequately studied to determine the reasons behind the increased methane production.

Ultrasonic pretreatment has been has been shown to be effective in disintegrating sewage sludge, resulting in greatly improved fermentation rates (Vera et al., 2004, pp 2127-2128). This method uses low-frequency ultrasound to induce cavitation with high shear forces, which promotes sludge disintegration. Short ultrasound bursts disperse sludge floc agglomerates without causing accompanying cell destruction. Longer ultrasound applications break down microorganism cell walls, causing intra-cellular material to be released to the liquid phase. The destruction of volatile solids increases according to the degree of cell disintegration. Increased biogas production was also observed. However, the application of this technology to manure solids is untried and its success uncertain due to the ligno-cellulosic character of manure.

Peltola et al. (2004, pp. 2,129 – 2,132) showed that impact grinding can increase the soluble *chemical oxygen demand* (COD) content of the organic fraction of municipal solid waste by approximately 2.5 times. This increased COD indicates partial disintegration of plant cells and microbial floc of the organic fraction of municipal solid waste. Though no increase in biogas production was observed, the onset of methane production began sooner as a result of impact grinding, and the digestion process was more stable than when the organic fraction of municipal solid waste was simply crushed. The breakdown of cell walls as a result of impact grinding could also improve the anaerobic digestion of dairy manure. However, any benefits that might be gained, such as an increased rate of biogas production and consequent reduction in hydraulic retention time and digester size, would need to be weighed against the increased energy (and resultant costs) required to grind the manure.

Microbial Stimulants

Aquasan® and Teresan® are *saponified* steroid products (available from Amit Chemicals in New Dehli, India) that are used to activate microbes. Both products are derived from plant extracts and work directly on the microbial population, restricting odor emissions by enzyme interference and accelerating digestion by stimulating the bacterial metabolism. In bench-scale experiments using Aquasan, a dosage level of 15 ppm was optimum for gas production, and resulted in production that was 55% higher than that from untreated cattle manure. In another bench-scale study, the addition of Teresan to the mixed residues of cattle manure and kitchen wastes at a concentration of 10 ppm produced 34.8% more gas than the uninoculated mixture (Singh et al., 2001, pp. 313-316). The efficacy of these microbial stimulants has not been demonstrated at the commercial scale.

Co-Digestion with Other Waste Sources

Co-digestion of manure with other substrates such as industrial wastes, grass clippings, food industry wastes, animal by-products (slaughterhouse waste), or sewage sludge can result in multiple benefits. This includes an improved nutrient balance of total organic carbon, nitrogen, and phosphorous, which results in a stable and maintainable digestion process and good fertilizer quality (Braun and Wellinger, 2003). Co-digestion also improves the flow qualities of the co-digested substrates. In addition, the economics of digester projects benefit from the increased gas production due to co-digestion and also from the income generated from tipping fees (i.e., waste disposal fees that are generally based on a per volume or weight basis).

Increased biogas production from the co-digestion of dairy manure and grease-trap waste has been documented at the Amersfoort wastewater treatment plant in the Netherlands (Mulder et al., 2004, pp. 2,064-2,068). The results at Amersfoort showed that the grease-trap waste was converted with an efficiency of 70% at a hydraulic retention time of 20 days. The biogas production rate was doubled from approximately 180,000 ft^3/d using sewage sludge alone to approximately 353,000 to 424,000 ft^3/d when co-digested with grease-trap waste.

As previously noted, the typical dairy farm biogas contains approximately 55% to 70% CH_4 and approximately 30% to 45% CO_2. The theoretical CH_4 to CO_2 ratios of various substrates were determined by Jewel et al. (1978) using the following equation, developed by McCarty (1964):

$$C_nH_aO_b + (n - a/4 - b/2)\ H_2O \rightarrow (n/2 - a/8 + b/4)\ CO_2 + (n/2 + a/8 - b/4)\ CH_4 \qquad (1)$$

The theoretical CH_4 content of biogas for various substrates, based on this equation, are presented in Table 2-2. More detail about the stoichiometry of the anaerobic digestion process of various substrates can be found in Appendix A.

Table 2-3 Theoretical Methane Content of Biogas

Substrate	Chemical Composition	Methane, % of Total Gas
Fat	$C_{15}H_{31}COOH$	72
Protein	C_4H_6ON	63
Carbohydrate	$C_6H_{12}O_6$	50

Readily degradable substrates (urea, fats, and proteins) yield the highest percentages of CH_4. However, the fats and proteins available from industrial wastes such as slaughterhouse and rendering operations may, in high concentrations, inhibit the anaerobic digestion process through the accumulation of volatile fatty acids and long chain fatty acids (Salminen et al., 2003; Broughton et al., 1998). When manure is added to the anaerobic digestion process, it acts as a buffer and provides the essential nutrients necessary for digestion, overcoming some of the operational problems associated with the anaerobic digestion of lipids and proteins. A tour of Swedish biogas plants taken by the authors of this report tends to support these conclusions (WestStart/CalStart, 2004). Table 2-3 presents the operational parameters for three of the Swedish biogas plants that were visited during this tour.

As seen in Table 2-3, large quantities of biogas with high CH_4 content can be produced from manure mixed with slaughterhouse and food processing waste; however, this level of production comes with certain operational restrictions. For example, at the Laholm plant, no more than 40% slaughterhouse waste is used in the process. When a higher percentage of slaughterhouse waste is included, yeasts are produced and the reactor must be evacuated for the process to be recovered. The Linkoping plant uses the highest percentage of slaughterhouse waste of the three plants. This plant monitors incoming loads for volatile fatty acids, alkalinity, and dry matter content and also monitors the reactor for these same parameters two to three times a week. If the digesters begin to foam as result of high volatile fatty acid content, manure is added to stabilize the process. The plant uses bench-scale fermenters to test new wastes. Thus, the Linkoping plant successfully uses a high percentage of slaughterhouse waste to produce high-methane biogas, as long as it maintains a high degree of process monitoring and control.

Table 2-4 Operational Parameters for Three Swedish Biogas Plants

Operational Parameter	Laholm Plant	Boras Plant	Linkoping Plant
Waste mass processed (tons/day)	14	82	148
Total solids content (%)	10	30	10 – 14
Waste composition	33% pig manure 27% dairy manure 40% slaughterhouse & potato peels	restaurant food & grease trap household food food processing slaughterhouse	75% slaughterhouse 15% food processing & pharmaceutical 10% manure
Biogas production (ft^3/hour)	~18,000	~14,000	~48,000
Biogas quality (% methane)	75	No data	70-74
Feedstock processing	slaughterhouse waste minced to ~0.5 inch	Muffin Monster® [a] (30% to 8% total solids)	slaughterhouse waste minced to ~0.5 inch
Reactors [b]	2	1	2
Operating temperature	95^{o} F (mesophilic)	~130^{o} F(thermophilic)	100^{o} F (mesophilic)
HRT	21 days	16 – 17 days	30 days
Pasteurization	~160° F for 1 hour	~160° F for 1 hour	~160° F for 1 hour
Process heat	10% of the biogas	10% – 15% of the biogas	-

[a] Muffin Monster is the registered trademark of JWC Environmental for grinding machines that reduce particle size of feedstock.

[b] Continuously-stirred tank reactors

Because of the limited degree of monitoring and process control available at dairy farms, the percentage of slaughterhouse waste would likely need to be limited to less than 33% by volume of the incoming waste stream to prevent yeasting or foaming problems. In addition, it would be appropriate to digest slaughterhouse and other food processing waste in a complete-mix digester, which gives a higher degree of control over the digestion process than do plug-flow and covered-lagoon digesters.

Effluent Absorption of Carbon Dioxide

The chemistry of the anaerobic digestion process indicates that the CH_4 content of anaerobic digesters is typically 55% to 65% and cannot be much higher than 70%, even if the substrate is all fats and vegetable oils (see Appendix A for a detailed analysis). However, some standard anaerobic digesters have produced biogas with a CH_4 content higher than would be expected based on the anaerobic digestion process alone.

Biogas methane contents of 65% to 80% appear to be the result of absorption of excess CO_2 in the digester effluent. Higher CH_4 content than this is not likely, as it is not possible for digester effluents to absorb the additional CO_2 that would be needed to produce higher methane biogas. In a few cases, such as when biogas has been collected from partially covered ponds, CH_4 contents as high as 90% have been observed, the result of absorption of CO_2 by the effluent, which is of limited capacity. Other anaerobic digestion processes, such as "two-phase" digestion, might produce marginal increases in CH_4 content, but these processes are not suitable for dairy wastes (and have limited success in other applications, as explained in Appendix A).

Centralized Digestion of Dairy Wastes for Biogas Production

Although many California dairies are following the trend towards increased animal numbers per dairy, about half of the state's dairy animals remain in smaller herds. The smaller dairies, mostly unable to afford individual manure digestion systems, may be able to cooperate with similar local enterprises to build and operate "community manure digestion facilities." Tanker trucks could be used to transport manure from various farms to a central treatment facility. Facility output could be returned to contributing farms or otherwise distributed in a controlled, regulated fashion. Such centralized treatment facilities are conceptually the same as large on-farm production facilities, with the addition of load-out points for tank truck pickup and discharge. Also, centralized facilities are likely to be larger than most on-farm digestion facilities.

Another option, especially when the local number of dairy cows is not sufficient to make centralized processing economically viable, is to seek other organic wastes for inclusion in the centralized system. Co-digestion of animal manures with food processing wastes in community digestion facilities is practiced in Denmark (University of Southern Denmark, 2000) and other European locations, and could be applicable also in some dairy areas in California. In particular, the addition of food processing wastes to manure could improve system economics, by providing waste-tipping fee revenues while generating more biogas.

Food-processing industries typically dispose of their waste streams through on-site aerobic treatment, discharge into sewer systems, sending solids to landfills, or regulated land application, all of which are relatively expensive. Recipients of these waste streams are required to meet local, state, and federal standards. Because food wastes are typically high in volatile solids concentration, they may produce significant odor when treated through land application. Food waste requires high energy inputs to process at a sewage treatment plant, where it can cause substantial sludge production, as well as requiring increased sewage treatment plant capacity.

Centralized Digesters and Gas Production

Centralized digesters have no intrinsic advantage with regard to gas production per unit volume as compared to on-farm digesters, but they will realize some *economies of scale* as the cost of anaerobic digestion per animal unit will decrease with herd size. However, trucking costs will reduce any economies realized. The main criterion with regard to gas production for both centralized and decentralized digesters is the age of the manure that reaches the digester. Ideally, collection should occur frequently enough that the manure used in digestion is no more than 3 days old. As manure ages it loses volatile solids, reducing the gas production potential. After about 30 days, manure biogas yield is very low.

Transport of Manure and Digested Effluent to Centralized Digesters

A major consideration for centralized digestion is the practicality of transportation. Manure must be transported from the various farms to the community or regional digester. After digestion, the digested liquid is transported back for field application, while the digested solids are typically composted and sold at the central digester location.

To understand how the transportation process might affect the viability of a centralized digester, we contacted Zwald Transport. They perform “two-way” hauling for the Port of Tillamook Bay regional digester. Mr. Zwald reported that the speed of loading and unloading is the key to success, and the best equipment to ensure this speed is a vacuum tanker. The process is also tightly controlled by the transporter: all of Zwald’s pick-up and delivery operations are under control of the driver and the farmer provides only the hose to the truck and pipe to the storage lagoon. The farmer is not required to buy a pump or valves or to modify any existing pumping system (Zwald, personal communication, November 2003).

Zwald’s truck is a 5,500-gallon vacuum tanker in a semi-trailer (combination) configuration. Larger units are possible, but the trade-off is maneuverability. A full load of digested liquid is taken on in 3 minutes, 30 seconds. Farm manure takes longer to load. There is some time variation due to the different loading situations, but the average time to load manure is around 7 minutes. The farm hoses (purchased by the farmers) are always ready to hook up to the truck. A suction hose is carried on the truck, but is used in emergencies only. Total turnaround time for a farm that is 2 miles from the digester site is about 55 minutes. One farm, 9 miles from the digester, has a total turnaround time of an hour and 35 minutes.

Another example of transportation services for an ongoing centralized digester is DeJaeger Trucking, which collects and hauls manure to the Inland Empire Utility Agency digester in Chino, California. DeJaeger uses a Honey Vac (a vacuum tanker truck) to collect the manure from the feed aprons, which have concrete floors. The manure contains 12% to 16% solids and the truck holds 25 tons. DeJaeger’s hauling rate is $45 per hour, and the furthest effective haul is about 5 miles. The cost of hauling is about $4/ton (DeJaeger, 2004).

These two examples illustrate the importance of distance, time, and other details that affect the viability of a centralized digester. Two general principles that should be adhered to when considering the start-up of a community digester include the following:

- Maximum haul distance to a centralized digester should be no more than 5 miles. A general rule of thumb is that manure from the equivalent of 6,000 mature Holstein cows must be available in a 5-mile radius of the centralized facility.
- Operational details such as collection, hauling, distribution, and costs must be carefully negotiated through contracts and maintained through active cooperation and management among participants.

Pumping manure through a pipeline is an alternative to trucking. However, this requires a higher moisture content in the manure, a suitable piping infrastructure, and pumping facilities. It is equivalent to building a sewage system for the manure.

3. Upgrading Dairy Biogas to Biomethane and Other Fuels

Dairy biogas can be combusted to generate electricity and/or heat. This report, however, focuses on alternate uses of biogas including the upgrading of biogas to biomethane, a product equivalent to natural gas or other higher-grade fuels. Biomethane, which typically contains more than 95% CH_4 (with the remainder as CO_2), has no technical barrier to being used interchangeably with natural gas, whether for electrical generation, heating, cooling, pumping, or as a vehicle fuel. The process can be controlled to produce biomethane that meets a pre-determined standard of quality. Biomethane can also be put into the natural gas supply pipeline, though there are major institutional barriers to this alternative.

As discussed in Chapter 2, raw dairy biogas typically contains 55% to 70% CH_4 and 30% to 45% CO_2 along with other impurities such as H_2S and water vapor. To produce biomethane from biogas, the H_2S, moisture, and CO_2 must be removed. This chapter provides an overview of the types of processes that can be used to remove these components, reviews the associated environmental impacts, and suggests the most practical processes for small facilities typical of dairy farm applications. In addition, this chapter explores the possibility of upgrading biogas to produce various higher-grade fuels:

- Compressed biomethane (CBM), which is equivalent to compressed natural gas (CNG)
- Liquid-hydrocarbon replacements for gasoline and diesel fuels (created using the Fischer-Tropsch process)
- Methanol
- Hydrogen
- Liquefied biomethane (LBM), which is equivalent to liquefied natural gas (LNG)

Upgrading Biogas to Biomethane

Biogas upgrading, or "sweetening," is a process whereby most of the CO_2, water, H_2S, and other impurities are removed from raw biogas. Because of its highly corrosive nature and unpleasant odor, H_2S is typically removed first, even though some technologies allow for concurrent removal of H_2S and CO_2. The following sections discuss various removal technologies with specific emphasis on those technologies most suitable for on-farm use.

Technologies for Removal of Hydrogen Sulfide from Biogas

The concentration of H_2S in biogas generated from animal manure typically ranges between 1,000 to 2,400 ppm, depending in large part on the sulfate content of the local water. Minor quantities of mercaptans (organic sulfides) are also produced, but are removed along with H_2S and need not be addressed separately. Even in low concentrations, H_2S can cause serious corrosion in gas pipelines and biogas conversion and utilization equipment as well as result in unpleasant odors and damage to the metal siding and roofing of buildings (Mears, 2001).

H_2S can be removed by a variety of processes, each of which is described below:

- Air injected into the digester biogas holder
- Iron chloride added to the digester influent
- Reaction with iron oxide or hydroxide (iron sponge)
- Use of activated-carbon sieve
- Water scrubbing
- Sodium hydroxide or lime scrubbing
- Biological removal on a filter bed

Air/Oxygen Injection

When air is injected into the biogas that collects on the surface of the digester, thiobacilli bacteria oxidize sulfides contained in the biogas, reducing H_2S concentrations by as much as 95% (to less than 50 ppm). The injection ratio is typically a 2% to 6% air to biogas ratio (a slight excess of O_2 over the stoichiometric requirement). Thiobacilli bacteria naturally grow on the surface of the digestate, and do not require inoculation. The by-product of this process is hydrogen and yellow clusters of elemental sulfur on the surface of the digestate.

Air injection directly into the digester's gas holder, or, alternatively, into a secondary tank or biofilter is likely the least expensive and most easily maintainable form of scrubbing for on-farm use where no further upgrading of biogas is required (i.e., when the biogas is being cleaned solely to prevent corrosion and odor problems, not to increase its methane content). However, the addition of the proper proportion of air presents significant control problems. Without careful control over the amount of air injected, this process can result in the accidental formation of explosive gas mixtures. Furthermore, such process results in some dilution with nitrogen (N_2), which is undesirable if CO_2 is to be subsequently removed and the resulting biomethane compressed for use as a vehicular fuel. Residual oxygen (O_2) would also be a concern for a pressurized gas.

Iron Chloride Injection

Iron chloride reacts with H_2S to form iron sulfide salt particles. Iron chloride can be injected directly into the digester or into the influent mixing tank. This technique is effective in reducing high H_2S levels, but less effective in maintaining the low and stable H_2S levels needed for vehicular fuel applications.

Iron Oxide or Hydroxide Bed

Hydrogen sulfide reacts endothermically with iron hydroxides or oxides to form iron sulfide. A process often referred to as "iron sponge" makes use of this reaction to remove H_2S from gas. The name comes from the fact that rust-covered steel wool may be used to form the reaction bed. Steel wool, however, has a relatively small surface area, which results in low binding capacity for the sulfide. Because of this, wood chips impregnated with iron oxide have been used as preferred reaction bed material. The iron-oxide impregnated chips have a larger surface-to-volume ratio than steel wool and a lower surface-to-weight ratio due to the low density of wood. Roughly 20 grams of H_2S can be bound per 100 grams of iron-oxide impregnated chips.

Iron oxide or hydroxide can also be bound to the surface of pellets made from red mud (a waste product from aluminum production). These pellets have a higher surface-to-volume ratio than steel wool or impregnated wood chips, though their density is much higher than that of wood chips. At high H_2S concentrations (1,000 to 4,000 ppm), 100 grams of pellets can bind 50 grams of sulfide. However, the pellets are likely to be somewhat more expensive than wood chips.

The optimal temperature range for this reaction is between 77° F and 122° F. The reaction requires water; therefore, the biogas should not be dried prior to this stage. Condensation in the iron sponge bed should be avoided since water can coat or "bind" iron oxide material, somewhat reducing the reactive surface area.

The iron oxide can be regenerated by flowing oxygen (air) over the bed material. Typically, two reaction beds are installed, with one bed undergoing regeneration while the other is operating to remove H_2S from the biogas. One problem with this technology is that the regenerative reaction is highly *exothermic* and can, if air flow and temperature are not carefully controlled, result in self-ignition of the wood chips. Thus some operations, in particular those performed on a small scale or that have low levels of H_2S, elect not to regenerate the iron sponge on-site.

For on-farm applications requiring both H_2S and CO_2 removal and compression of the biomethane gas, the iron sponge technology using iron-impregnated wood chips appears to be the most suitable. One farm digester reported that an iron sponge reduced H_2S to below 1 ppm, quite sufficient for all purposes (Zicari, 2003, page 18).

Activated Carbon Sieve

In pressure-swing adsorption systems, H_2S is removed by activated carbon impregnated with potassium iodide. The H_2S molecule is loosely adsorbed in the carbon sieve; selective adsorption is achieved by applying pressure to the carbon sieve. Typically, four filters are used in tandem, enabling transfer of pressure from one vessel to another as each carbon bed becomes saturated. (The release of pressure allows the contaminants to desorb and release from the carbon sieve.) This process typically adsorbs CO_2 and water vapor in addition to H_2S. To assist in the adsorption of H_2S, air is added to the biogas, which causes the H_2S to convert to elementary sulfur and water.

The sulfur is then adsorbed by the activated carbon. The reaction typically takes place at a pressure of around 100 to 115 pounds per square inch (psi) and a temperature of 122 to 158° F. The carbon bed has an operating life of 4,000 to 8,000 hours, or longer at low H_2S levels. A regenerative process is typically used at H_2S concentrations above 3,000 ppm.

Water Scrubbing

Water scrubbing is a well-established and simple technology that can be used to remove both H_2S and CO_2 from biogas, because both of these gases are more soluble in water than methane is. Likewise, H_2S can be selectively removed by this process because it is more soluble in water than carbon dioxide. However, the H_2S desorbed after contacting can result in fugitive emissions and odor problems. Pre-removal of H_2S (e.g., using iron sponge technology) is a more practical and environmentally friendly approach.

Water scrubbing is described below in more detail as a method to remove carbon dioxide.

Selexol Scrubbing

Selexol™ is a solution of polyethylene glycol that can be used for the simultaneous scrubbing of biogas for CO_2, H_2S and water vapor. However, because elementary sulfur can be formed when Selexol is stripped with air (during regeneration), prior removal of H_2S is preferred. The Selexol technology is described in more detail below as a method to remove CO_2.

Sodium Hydroxide Scrubbing

A solution of sodium hydroxide (NaOH) and water has enhanced scrubbing capabilities for both H_2S and CO_2 removal because the physical absorption capacity of the water is increased by the chemical reaction of the NaOH and the H_2S. The enhanced absorption capacity results in lower volumes of process water and reduced pumping demands. This reaction results in the formation of sodium sulfide and sodium hydrogen sulfide, which are insoluble and non-regenerative. (The NaOH also absorbs CO_2, which could, in principle, be partially regenerated by air stripping; however in practice, the process is not regenerative and is thus prohibitively expensive.)

Biological Filter

A biological filter combines water scrubbing and biological desulfurization. As with water scrubbing, the biogas and the separated digestate meet in a counter-current flow in a filter bed. The biogas is mixed with 4% to 6% air before entry into the filter bed. The filter media offer the required surface area for scrubbing, as well as for the attachment of the desulfurizing (H_2S oxidizing) microorganisms. Although biofiltration is used successfully to remove odors from exiting air at wastewater treatment plants, and suitable media (e.g., straw, etc.) is available on farms, some oxygen would need to be added to the biogas. We are unaware of any instance where biofiltration has been usefully applied to remove H_2S from streams of oxygen-free biogas.

Technologies for Removal of Water Vapor

Because biogas from digesters is normally collected from headspace above a liquid surface or very moist substrate, the gas is usually saturated with water vapor. The amount of saturated water vapor in a gas depends on temperature and pressure. Biogas typically contains 10% water vapor by volume at 110^{o} F, 5% by volume at 90^{o} F, and 1% by volume at 40^{o} F (Weast, 1958). The removal of water vapor (moisture) from biogas reduces corrosion that results when the water vapor condenses within the system. Moisture removal is especially important if the H_2S has not been removed from the biogas because the H_2S and water vapor react to form sulfuric acid (H_2SO_4), which can result in severe corrosion in pipes and other equipment that comes into contact with the biogas. Even if the H_2S has been removed, water vapor can react with CO_2 to form carbonic acid (H_2CO_3), which is also corrosive (pH near 5). When water vapor condenses within a system due to pressure or temperature changes, it can result in clogging of the pipes and other problems as well as corrosion.

A number of techniques can be used to remove condensation from a pipe, including tees, U-pipes, or siphons. The simplest method to remove condensation water is to install horizontal pipe runs with a slope of 1:100. A drip trap or condensate drain can then be located at all low points in the piping to remove condensation. However, this will only remove water vapor that condenses in the piping. The simplest means of removing excess water vapor to dew points that preclude downstream condensate in biogas is through refrigeration. In a refrigerator unit, water vapor condenses on the cooling coils and is then captured in a trap.

The dew point of biogas is close to 35^{o} F. As mentioned, at 90^{o} F the biogas contains 5% water vapor, which has a density of about 0.002 lb/ft^3. At 105^{o} F, the water vapor content doubles to 0.004 lb/ft^3. At this temperature, for example, a thousand cow dairy that produces 2,000 ft^3/h of biogas would yield about 4 lb of condensation water per hour (when all the water vapor is condensed). The latent heat of vaporization of water is 1,000 Btu/lb of water. Therefore, condensation of 5 lb of water will require 5,000 Btu/hour, which is a little less than 0.5 ton of refrigeration.

Refrigerators with capacities of 0.5 to 1 ton are commercially available and easily used on a dairy. Scrubbing of the biogas to remove H_2S prior to refrigeration would significantly lengthen the life of the refrigeration unit. The power needed for this type of refrigeration unit would be modest, less than 2% of the biogas energy content.

Technologies for Removal of Carbon Dioxide

The technologies available for removal of CO_2 from dairy manure biogas are typically used for larger scale applications such as upgrading natural gas from “sour” gas wells, sewage treatment plants, and landfills. Because of the different contaminants, scales, and applications, removal of

CO_2 from dairy manure biogas will differ significantly from these applications and requires a case-by-case analysis.

The following processes can be considered for CO_2 removal from dairy manure biogas. The processes are presented roughly in the order of their current availability for and applicability to dairy biogas upgrading:

- Water scrubbing
- Pressure swing adsorption
- Chemical scrubbing with amines
- Chemical scrubbing with glycols (such as Selexol™)
- Membrane separation
- Cryogenic separation
- Other processes

Water Scrubbing

When water scrubbing is used for CO_2 removal, biogas is pressurized, typically to 150 to 300 pounds per square inch, gauge (psig) with a two-stage compressor, and then introduced into the bottom of a tall vertical column. The raw biogas is introduced at the bottom of the column and flows upward, while fresh water is introduced at the top of the column, flowing downward over a packed bed. The packed bed (typically a high-surface-area plastic media) allows for efficient contact between the water and gas phases in a countercurrent absorption regime. Water often pools at the bottom of the contact column and the biogas first passes through this water layer in the form of bubbles. The CO_2-saturated water is continuously withdrawn from the bottom of the column and the cleaned gas exits from the top.

A purity of about 95% methane can be readily achieved with minimal operator supervision in a single pass column. After scrubbing, the water can be regenerated (i.e., stripped of CO_2 by contacting with air at atmospheric pressures, either in a packed bed column similar to the one used for absorption, or in a passive system such as a stock pond).

This type of system was apparently first used in the USA for stripping CO_2 from biogas at a wastewater treatment plant in Modesto, California and is currently used at the King County South Wastewater Treatment Plant in Renton, Washington (Figure 3-1). It is also the most commonly used biogas clean-up process in Europe. The Modesto plant, operated in the 1970s and early 1980s, was rather simple and crude, and had no separate H_2S removal system. It produced a renewable methane stream that was compressed to fuel vehicles at the sewage treatment plant. The system was discontinued due to corrosion problems as well as lack of interest when the energy crisis abated.

At the Renton plant near Seattle, approximately 150,000 ft^3 of biomethane (95%+ CH_4) are produced daily and injected into a medium-pressure pipeline. Because a large amount of treated water is available at Renton (and other wastewater treatment plants), a single-pass process with no water regeneration stage can be used, which saves the cost of regenerating CO_2-laden water. Dairy operations could similarly avoid the regeneration stage by using available on-farm stock water.

In addition to being a simple, well-established, and relatively inexpensive technology, water scrubbing typically loses relatively little CH_4 (less than 2%) because of the large difference in solubility of CO_2 and CH_4. Methane losses can be larger, however, if the process is not optimized.

A water scrubbing system preceded by H_2S removal would be a practical, low-cost process for upgrading dairy biogas to biomethane. It is important that the H_2S be removed prior to the removal of the CO_2, as H_2S is highly corrosive and would result in decreased life and higher maintenance of the subsequent compressors required in the CO_2-removal step.

Figure 3-1 Carbon dioxide absorption towers at the King County South Wastewater Treatment Plant

Our research indicates that all but one or two of the dozen municipal wastewater treatment plants where sewage biogas is upgraded use water scrubbing. The other main processes used for CO_2 removal at wastewater treatment facilities are pressure swing adsorption (used mainly by Kompogas in Switzerland) and membrane technology, both of which are discussed below. Solvents other than water (e.g., glycols or amines) have not been used except at a few landfill sites and at the Gasslosa plant in Sweden, where the Cirmac process is used (see discussion, below).

One reason for the prevalence of water scrubbing at wastewater treatment plants is that these plants have an abundance of water, and thus can use a single-pass system, with no need for water regeneration. This greatly simplifies operations. Some dairy operations also have water in sufficient quantities for a single-pass system, and could use the wastewater from a water-scrubbing system for certain dairy operations such as washing stalls. If the wastewater were stored in stock ponds, the CO_2 would be released on its own over a period of a few days (faster with some aeration).

The disadvantage of water scrubbing is that it is less efficient than other processes, both in terms of CH_4 loss and energy. However, some of the energy inefficiency of the process may be offset by the use of a single-pass water scrubbing system, since other processes require a regeneration stage.

Water scrubbing is the most applicable CO_2 scrubbing process for use in an agricultural setting because of its simplicity and low cost. On a dairy farm, these factors would be more important than efficiency, reduced footprint, and redundancy. Another advantage of water scrubbing over some other processes is that water is fairly easy to dispose of whereas the chemicals used in some of the other processes may require special handling and disposal when spent.

Pressure Swing Adsorption

This approach uses a column filled with a molecular sieve (typically an activated carbon) for differential sorption of the gases, such that CO_2 and H_2O adsorb preferentially, letting CH_4 pass through. The process is operated under moderate pressures. Several columns, typically four, are operated sequentially to reduce the energy consumption for gas compression (Figure 3-2) and the gas pressure released from one vessel is subsequently used by the others. The first column cleans the raw gas at about 90 psi to an upgraded biogas with a vapor pressure of less than 10 ppm H_2O and a CH_4 content of 96% or more. In the second column, the pressure of 90 psi is first released to approximately 45 psi by pressure communication with the fourth column, which was previously degassed by a slight vacuum. The pressure in the second column is then reduced to atmospheric pressure and the released gas flows back to the digester so that the CH_4 can be recovered. The third column is evacuated from about 15 to about 1 psi. The desorbed gas consists predominantly of CO_2 and is normally vented to the environment even though it contains some residual CH_4. To reduce CH_4 losses, the system can be designed so that desorbed gases recirculate to the pressure swing adsorption system or even the digester.

This process produces a water-free gas that is cleaner than gas produced by other techniques such as water scrubbing; however, it requires considerably more sophistication and increased process controls, including careful recycling of a fraction of the gas to avoid excessive CH_4 losses. Another drawback is its susceptibility to fouling by contaminants in the biogas stream.

Automated cycling of multiple columns is used by Air Products, Inc. at the Olinda Landfill in California. Smaller automated systems would be more applicable to dairy farm use.

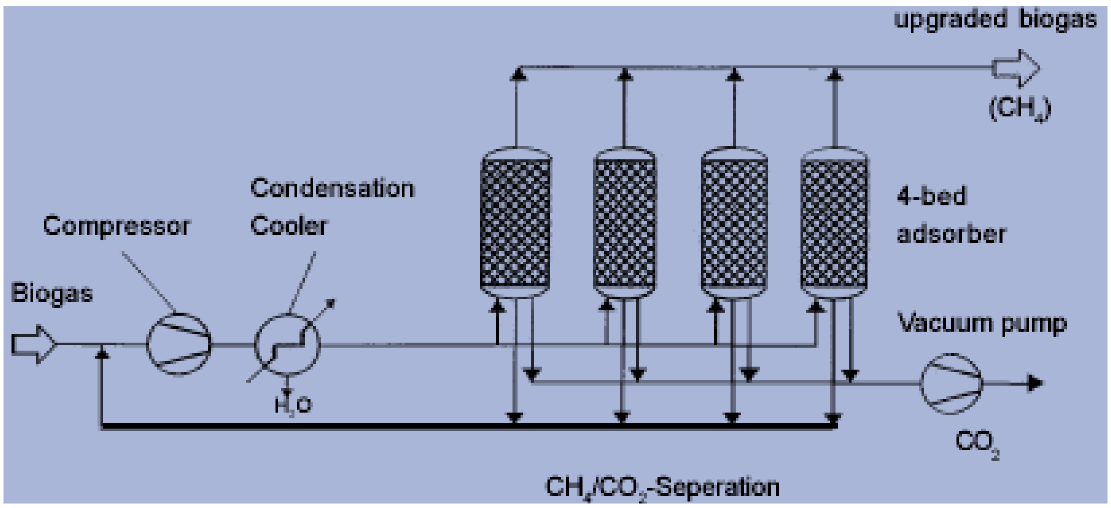

Figure 3-2 Schematic of a pressure swing absorption system with carbon molecular sieves for upgrading biogas

Chemical Scrubbing With Amine Solvents

Amine scrubbing is widely used in food-grade CO_2 production and has also become the preferred technology for large-scale systems that recover CO_2 from natural gas wells. More recently, amine scrubbing technologies have played a key role in CO_2 removal from power plant flue gases as part of GHG abatement programs. The process uses organic amines (monoethanolamine [MEA], diethanolamines [DEA], and diglycolamines [DGA]) as absorbers for CO_2 at only slightly elevated pressures (typically less than 150 psi). The amines are regenerated by heating and pressure reduction to drive off the CO_2, which can be recovered as an essentially pure by-product of the process.

The principle of amine scrubbing is represented by the following general chemical equations:

CO_2 sorption: $RNH_2 + H_2O + CO_2 \rightarrow RNH_3^+\ HCO_3^-$ (under pressure) (1)

CO_2 desorption: $RNH_3^+\ HCO_3^- \rightarrow RNH_2 + H_2O + CO_2$ (low pressure, some heat) (2)

(R represents the remaining organic component of the molecule that is not relevant to this equation.)

One advantage of the amine approach is the extremely high selectivity for CO_2 and the greatly reduced volume of the process; one to two orders of magnitude more of CO_2 can be dissolved per unit volume using this process than with water scrubbing. If waste heat is available for the amine-scrubbing stage, the overall energy use is lower than for other processes such as Selexol™ or water scrubbing. The process has been scaled-down for landfill applications and works relatively well.

The main problems are corrosion, amine breakdown, and contaminant buildup, which make it problematic to apply this process to small-scale systems such as dairy farms. However, dairy manure biogas typically has fewer contaminants of concern than biogas sources such as landfills, and steel pipes can be used to minimize corrosion.

Cirmac, a Dutch company, has developed a proprietary amine (COOAB™) scrubbing process that is used at the Gasslosa biogas plant in Boras, Sweden (Figure 3-3). One advantage of this process is its very low CH_4 loss; one disadvantage is that it is a more complex technology. However, most of the system complexities are not visible to the operator of the COOAB packaged unit and Cirmac is actively promoting its technology for small-scale biogas upgrading (see <http://www.cirmac.com/>).

Chemical Scrubbing with Polyethlylene Glycols

Polyethylene glycol scrubbing, like water scrubbing, is a physical absorption process. Selexol™ is the main commercial process using this solvent, and it is used extensively in the natural gas industry as well as other applications. Carbon dioxide and H_2S have even greater solubility

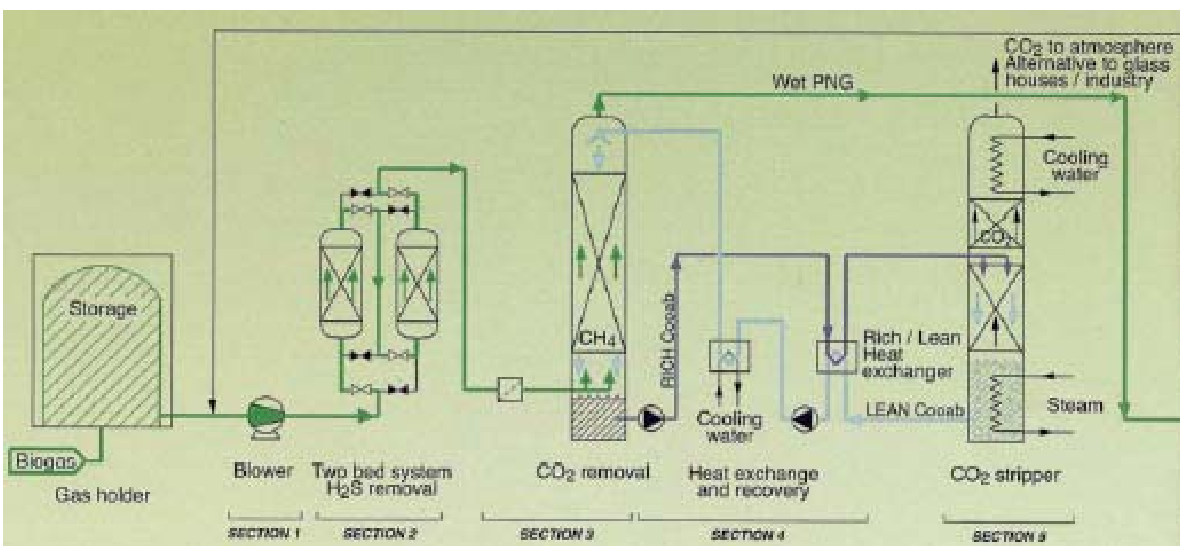

Figure 3-3 Cirmac amine carbon dioxide absorption process (LP Cooab™) for upgrading biogas (Source: Cirmac, Undated)

relative to methane in Selexol fluid than in water, which results in a lower solvent demand and reduced pumping. Selexol is typically kept under pressure, which improves its capability to absorb these contaminants. In addition, water and halogenated hydrocarbons (contaminants in landfill gas) are removed when scrubbing biogas with Selexol.

Selexol scrubbing systems are always designed with recirculation. The Selexol solvent is stripped with steam; stripping the Selexol solvent with air is possible but not recommended because of the formation of elementary sulfur. (Prior removal of H_2S is preferred for this reason.) The Selexol process has been used successfully to upgrade landfill gas at several landfill sites in the USA. The major drawback is that the process is more expensive for small-scale applications than water scrubbing or pressure swing adsorption.

Membrane Separation

The most common membrane separation process uses pressure and a selective membrane, which allows preferential passage of one of the gases. Due to imperfect separation, several stages are generally used. During the 1990s Clean Fuels Corporation designed and operated a landfill gas purification system that produced vehicular fuel at the Puente Hills Landfill in Los Angeles County (Roe, et al., 1998). This small system, which treated only about 1% of the total landfill gas flow, had a capacity of about 90 standard cubic feet per minute (scfm) and produced the natural gas equivalent of about 1,000 gallons of gasoline daily.

The Puente Hills process (shown schematically in Figure 3-4) used a water knockout tank to remove condensate from the raw landfill gas, followed by a three-stage compression system that

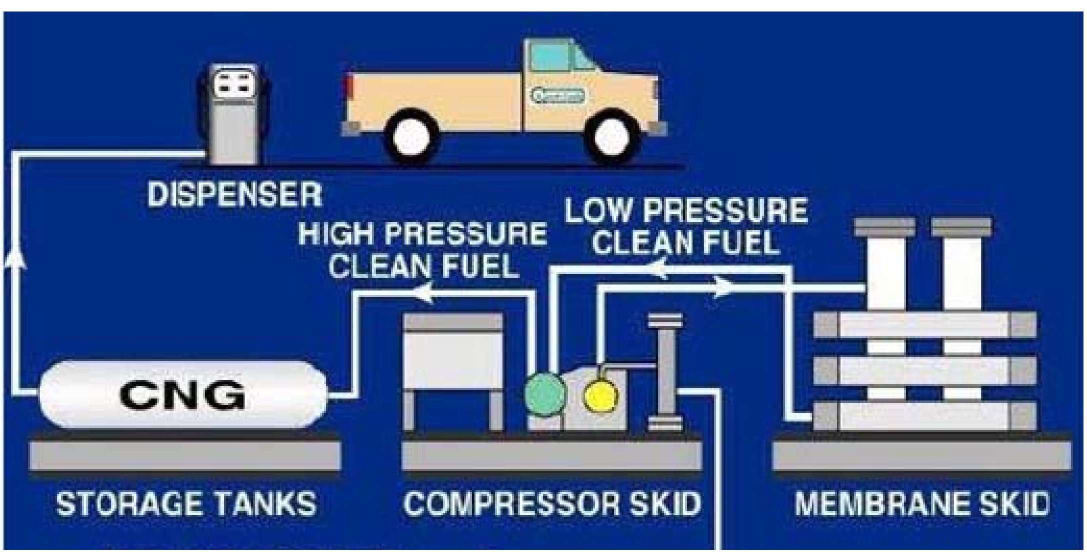

Figure 3-4 Schematic of Puente Hills landfill gas carbon dioxide – methane separation process (Source: Sanitation Districts of Los Angeles County, http://www.lacsd.org/swaste/Facilities/LFGas/CNGFacility.htm)

increased pressure from 41 to 150 to 525 psi. Next, an activated carbon absorption system removed impurities and a heater increased the gas temperature to 140° F before the gas entered a three-stage acetate membrane separation unit. About 15% of the gas, which contained about 80% CH_4, was recycled to the head of the system. The remaining 85% of the gas, which contained about 96% CH_4, was compressed and stored at 3,600 psi. Some tanks were kept at medium and others at higher pressure, allowing for sequential fast filling by the fuel dispenser.

Major problems with compressor oil carryover, corrosion, and other operational issues were encountered at the Puente Hills Landfill. Membrane life was not as long as expected, with a 30% loss in permeability after 1.5 years. The process had to be carefully monitored, in part due to the variable nature of landfill gas, which often contains large amounts of nitrogen gas from air intrusion, in addition to other contaminants. Methane losses were significant, but not documented.

Membrane processes are also used at several plants in Europe, but less detail is available on these operations. New low-pressure membranes are being developed that could be more effective for CO_2 removal.

Cryogenic Separation

Because CO_2, CH_4, and contaminants all liquefy at very different temperature-pressure domains, it is possible to produce CH_4 from biogas by cooling and compressing the biogas to liquefy CO_2 which is then easily separated from the remaining gas. The extracted CO_2 also can be used as a solvent to remove impurities from the gas. A cryogenic separation has been proposed by Acrion Technologies (Cleveland, Ohio) to purify landfill gas, which contains halocarbons, siloxanes and VOCs and is thus more challenging to clean-up than dairy manure biogas. In the Acrion scheme, considerable CO_2 is still present in the biomethane after processing. Removal of this CO_2 requires a follow-up membrane separation step, or CO_2 wash process, mainly to remove impurities and produce some liquid CO_2 (Figure 3-5). This wash process has been demonstrated at a landfill in Columbus, New Jersey.

The economics of cryogenic separation still need to be assessed and further development is needed before cryo-separation can be considered ready for applications. A potential problem with cryo-separation is that its costs of separation tend to drop sharply with increasing scale and its cost-effectiveness at small scales has not been established. No information is available on using cryogenic separation solely for CH_4 purification (i.e., not in conjunction with other cleanup technologies).

This process might be worth considering if the end objective is to produce liquefied biomethane (LBM), a product equivalent to liquefied natural gas (LNG). In this case, the refrigeration process needed for cryo-separation would likely be synergistic with the further cooling required for LBM production. Determining the actual technical and economic feasibility of combining these processes, however, is beyond the scope of this study.

Other Technologies for Carbon Dioxide Removal

There are literally dozens of vendors of alternative technologies for CO_2 removal from gases. Many of these have been spurred by recent interest in separation of CO_2 from power plant flue gases for purposes of CO_2 sequestration. Commercial CO_2 removal technologies have been in use for several decades to produce CO_2 for processed foods (e.g., soft drinks, etc.), for tertiary oil recovery, and for natural gas purification. It is not apparent, however, that the present increase in research in this field has produced any new or superior technologies applicable to biogas upgrading. The main commercial processes for power plant flue gas clean-up are the amine processes (described above), which have proved to have superior economic performance. Organic solvents—in particular methanol—have also been used for CO_2 removal, but have also fallen out of favor due to high costs. The use of hot potassium carbonate solutions, which are often mixed with various other chemicals to facilitate the process, are similarly considered obsolete technology. A recently proposed process uses refrigeration to produce CO_2 clathrates (water complexes) that can be easily recovered; however, this process is still at a very early exploratory stage. In conclusion, despite the worldwide search for "game-changing" technologies for CO_2 removal from power plant emissions, none have yet been identified.

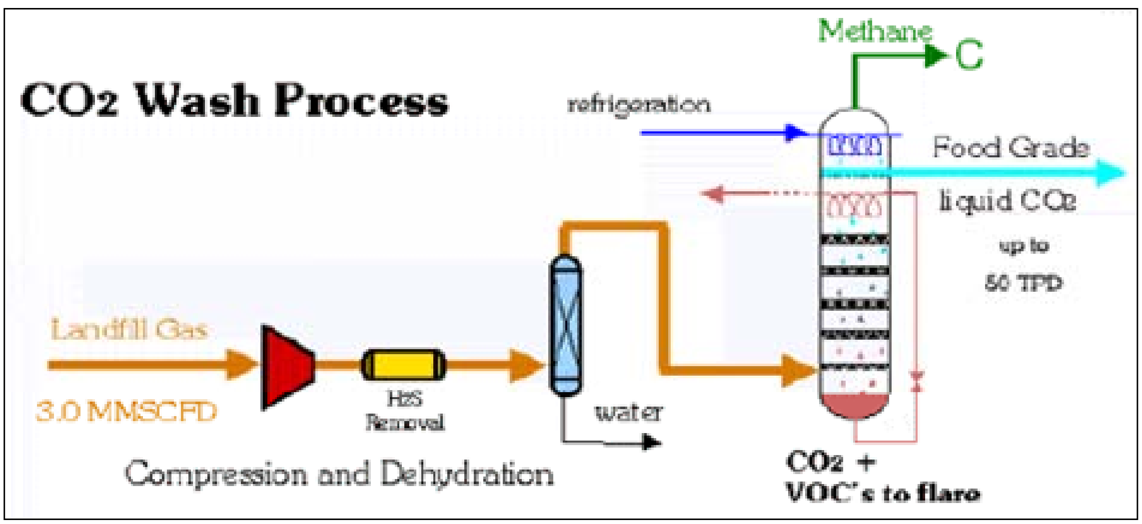

Figure 3-5 Carbon dioxide scrubbing process developed by Acrion Technologies (source: Acrion Co. <www.acrion.com>)

Environmental Effects of Gas Cleanup Technologies

Materials used in adsorption gas cleanup technologies such as iron sponge, activated carbon sieve, and other molecular sieves can be regenerated. The iron sponge bed can be recovered by oxidizing it with air, forming iron oxide and elemental sulfur. Activated carbon is typically regenerated with steam, and other molecular sieves (such as zeolites) are regenerated by passing a heated gas (400^{o} to 600^{o} F) over the bed. The sulfur remains attached to the surface of the iron sponge bed material after regeneration, requiring replacement of the bed media after a number of cycles. Elemental sulfur is not hazardous, and the bed material can be disposed of through composting or at a landfill (F.Varani, Honeywell PAI, personal communication, September 2004). Thus, these technologies are considered environmentally friendly.

Liquid based (aqueous) absorption processes such as scrubbing with water, sodium hydroxide, amines, or glycols present disposal challenges. The most benign of these solvents is water. However, H_2S should be removed by a method other than water scrubbing to prevent fugitive H_2S emissions

Chemical removal processes have significant potential for chemical pollution from the accidental release of chemicals or from their final disposal. Chemicals may degrade during use because of contamination with pollutants in the biogas (although this should be less of a problem with dairy biogas than with sewage or landfill gas), corrosion, and other problems. The disposal of spent and degraded chemicals may pose a hazardous waste disposal issue for both CO_2 and H_2S scrubbing. The use of sodium hydroxide for H_2S scrubbing results in large volumes of wastewater contaminated with sodium sulfide and sodium hydrogen sulfide, insoluble salts whose disposal is environmentally sensitive. Polyethylene glycol (Selexol process) and amines are not as problematic as these solvents are recirculated and stripped of elemental sulfur using an inert gas or steam.

Biological gas clean-up technologies for H_2S, such as a biological filter bed or injection of air into the digester gas holder, result in the sulfur particles flowing out with the digestate. Due to the low concentrations of H_2S in the dairy biogas and the large volumes of digestate involved this does not result in a disposal problem.

Possible Design for Small Dairy Biomethane Plant

A small dairy biogas upgrading plant might consist of the following:

- Iron sponge unit to remove H_2S
- Compressors and storage units
- Water scrubber with two columns to remove CO_2
- Refrigeration unit to remove water
- Final compressor for producing CBM, if desired

Table 3-1 provides basic system parameters for such a system, which is scaled to a dairy farm with 1,500 cows with an assumed CH_4 production of 30 ft3/cow/day.[1]

Table 3-1 Components for Typical Small Biogas Upgrading Plant

Component	Size/Capacity
Iron sponge H_2S scrubber	• 70,000 ft^3/day • 6 ft. dia x 8 ft. high
First-stage compressor (centrifugal blower)	• intake capacity = 100 ft^3/m compression to 8 psig
Modified piston compressor	• 1st stage compression from 8 to 40 psig • 2nd stage compression from 40 to 200 psig
Pressurized storage tanks	2 x 5,000 gal. propane tanks
Water CO_2 scrubber	• Two 12-inch diameter x 12-ft columns with Jaeger packing • water pump, piping, pressure valves, regulators • operates at pressures between 200 and 300 psig
Flash tank, gas recycler, chiller to reduce moisture	
High-pressure compressor	compression from 200 to 3,000 psig (small unit)
Additional components that may be needed	• refrigeration • contingencies • engineering hook-ups • infrastructure

[1] Various sources provide different average methane yields per cow. For example, Mehta (2002) cites Parsons (1984) as suggesting a biogas yield of 54 ft^3 per cow per day; since biogas has an estimated heat value of 600 Btu/ft^3, this means one cow would generate about 32.4 ft^3/day of CH_4. Other gas yields cited by Mehta (2002) include 139 ft^3/cow/day at Haubenschild Farm (as cited by Nelson and Lamb, 2000) and a design estimate of 65 ft^3/cow/day (Craven Farms, as cited by Oregon Office of Energy). Barker (2001) states that a 1,400 lb cow will yield about 30 ft^3 of CH_4 day. This is also the figure we use in this report based on the following:

1. An average cow weighs 1,400 lb and produces 120 lb/day of manure containing 11.33 lb of volatile solids.
2. Manure is collected within 2 days of deposition.
3. 1 lb of 2-day-old volatile solids from a dairy cow anaerobically digests to produce 3 ft^3 of methane.
4. The percent of manure collected in California, by farm type, is: 90% on flush free stall dairies, 90% of scrape freestall dairies, 60% on flushed feedlane drylot dairies, and 15% on dry lot dairies.
5. Solids separation reduces biogas production potential by 25%.
6. Using flushed and scraped freestall dairies as our standard and multiplying this out: $1.4 \times 11.3 \times 3 \times 0.9 \times 0.75 = 32$ ft^3 of methane per cow, which we have chosen to round conservatively to 30 ft^3/cow for most of our calculations.

The iron sponge H_2S scrubber would be an insulated fiberglass with a removable top cover for spent sponge removal. The iron oxide bed would last about one year. After H_2S removal, compressors would pressurize the gas and two packed columns would be used for the CO_2 water scrubbing process. The total system would be mounted on a small skid including water pump, piping, pressure valves and regulators. Other equipment needed in process would include a flash tank and gas recycler, as well as a chiller to reduce moisture content prior to final compression.

Process water could be re-used on the farm (for dairy barn cleaning, irrigation, or a stock pond). If stored in a stock pond, it could be recycled after a day or two of open air storage.

Figure 3-6 is a schematic of an on-farm water scrubbing process for CO_2 (but does not include iron sponge removal of H_2S). The final stage in the system (also not shown in Figure 3-6) would be a compressor to produce compressed biomethane, assuming this type of vehicle fuel is desired.

Operation and maintenance of this system would be relatively simple, which is one reason it is recommended over other, possibly more efficient, processes. Electricity for the compressors could be produced from an on-site generator using biogas (biogas could also be used to generate power for other on-site uses) or from purchased power. If purchased power were used, the major operating costs for this process would be for power for gas compression.

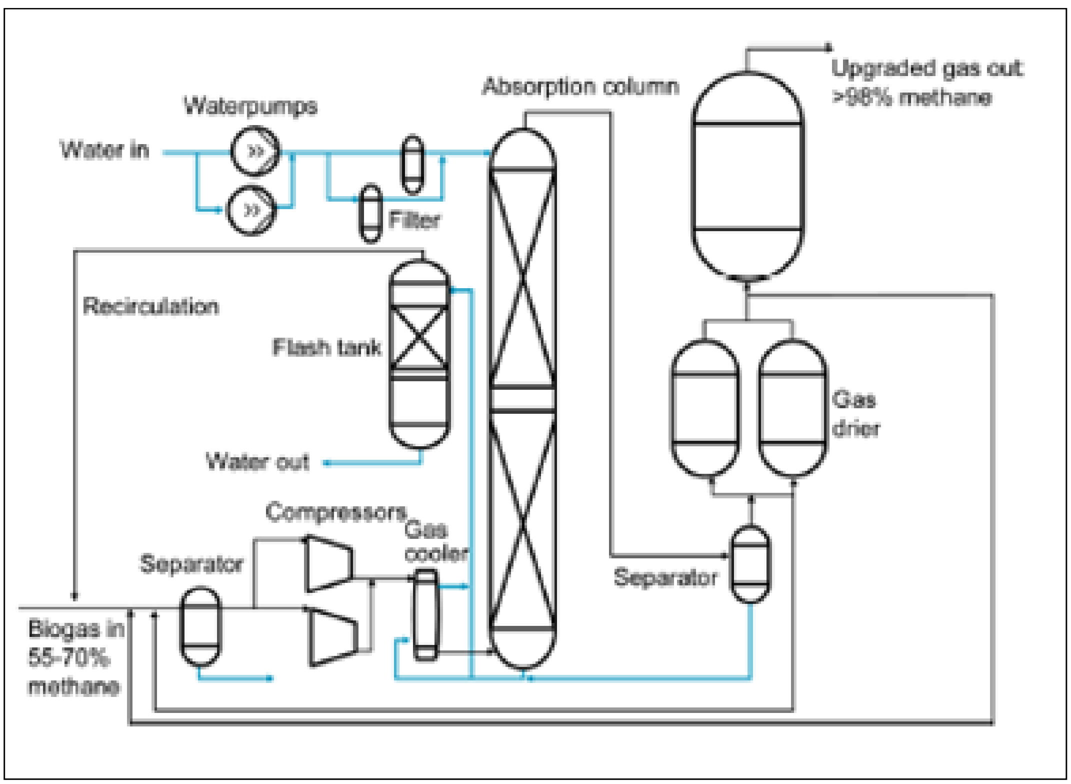

Figure 3-6 Water scrubbing process to remove carbon dioxide from biogas without regeneration (source: Hagen et al., 2001, Figure 7)

Capital and operating costs for a relatively small-scale plant with the capacity to upgrade biogas from 1,500 cows are discussed in more detail in Chapter 8. Our research suggests that a farm of about 1,500 dairy cows is the lower limit of scale for this technology.

Blending Biogas with More Valuable Fuels

The addition of propane or liquefied petroleum gas (LPG), which is gaseous at ambient pressure, is sometimes used to increase the heating value of natural gas in order to meet pipeline quality specifications and could do the same for biomethane. The percentage of propane or LPG mixed in with natural gas tends to be low (i.e., less than 8%) for cost reasons. Since this method does not increase the overall CH_4 content of the gas, it is not by itself sufficient for upgrading biogas to biomethane.

Hypothetically, a small amount of raw or partially purified biogas could be mixed with a larger amount of natural gas from the natural gas pipeline to create a blended feedstock for a town gas system. Although this has been done in Europe, we have no such systems in the USA and blending biogas and natural gas would be inappropriate for producing pipeline quality gas (there would still be too much H_2S and CO_2 present. The basic effect of the addition of the biogas would be to reduce the average CH_4 content of the blended gas feedstock and increase its level of contaminants. As an example, assuming natural gas with 92% CH_4 and raw biogas with 65% CH_4, a blending ratio of 6:1 or greater would yield a blended gas with the required 88% methane or better. Pre-blending of raw or partially purified biogas with natural gas or other fuels offers no advantages in the production of either LNG or CNG.

Compressing Biomethane

Biomethane compressed to about 3,600 psi is referred to in this report as compressed biomethane (CBM). Compositionally, it is equivalent to compressed natural gas (CNG), an alternate vehicular fuel, which contains about 24,000 Btu/gallon compared to approximately 120,000 for gasoline and 140,000 for diesel fuel. Consequently, CNG (or CBM) vehicles have both larger fuel tanks and a more limited driving range than traditionally fueled vehicles. Bi-fueled vehicles that could switch from CNG (or CBM) to gasoline would allow for longer driving ranges and less dependence on CNG refueling stations. However, infrastructure costs for distribution and fueling stations present a major hurdle for off-farm use of dairy biomethane (see Chapter 4).

Converting Biomethane to Non-Cryogenic Liquid Fuels

There is considerable interest in the production of renewable liquid fuels that could be used more directly in the existing transportation fleet and could overcome the volume, range, and weight limitations imposed by CBM (or CNG). For example, the energy contents of methanol and liquefied biomethane (LBM, equivalent to LNG) are about 65,000 and 84,000 Btu/gallon, respectively, much closer to the energy density of gasoline or diesel fuel than CNG (or CBM) and thus better suited for existing passenger vehicle applications.

In addition to liquefied biomethane (LBM), which is discussed at the end of this chapter, two main technologies exist for converting biogas to liquid fuels: catalytic conversion to methanol, and Fischer Tropsch synthesis for hydrocarbon fuels production. The initial steps to produce these liquid fuels from biomethane—the methane-reforming and catalytic conversion processes—are described below.

Methane-Reforming and Catalytic Conversion Processes

The conversion of methane (from natural gas) to liquid fuels can be accomplished through a methane-reforming process along with steam to produce synthesis gas (consisting of CO, H_2, and CO_2). This synthesis gas can then be catalytically converted to methanol or hydrocarbon fuels. The key to these processes is the nature and specificity of the catalysts, as well as the methane to CO-H_2 conversion reaction. The two basic processes used for methane conversion are steam reforming (Equation 3) or dry reforming (Equation 4):

$CH_4 + H_2O \rightarrow CO + 3H_2$	steam reforming, at 1500^o F	(3)
$CH_4 + CO_2 \rightarrow 2CO + 2H_2$	dry reforming, at 2200^o F	(4)
$CO + 2H_2 \rightarrow CH_3OH$	methanol synthesis	(5)
$CO + 2H_2 \rightarrow (CH_2) + H_2O$	Fischer Tropsch	(6)

A range of iron or copper catalysts are typically used for the catalytic conversion process to liquid fuels; different catalysts will selectively produce one product or the other. Furthermore, these catalysts are very sensitive to impurities, specifically H_2S. This requires careful scrubbing of the H_2S, but also of mercaptans (organic sulfur compounds) and other impurities.

The main drawbacks of both methane-reforming and catalytic conversion processes are the high temperatures and pressures at which they must be operated, as well as their complexity. Complexity comes from, among other causes, the requirement for efficient heat (energy) exchange and recovery among process components. Process control is a significant issue. An additional major factor for the poor economies of scale (both capital and operating) of such systems is the requirement for high-pressure compressors. Both processes require a relatively large scale for economic performance as smaller systems are not much cheaper than larger ones.

Biomethane to Gasoline Using the Fischer-Tropsch Process

The Fischer-Tropsch method has been in use since the 1920s to convert coal, natural gas, and other “low-value” fossil fuel products into a high-quality, clean-burning fuel. The performance of Fischer-Tropsch fuels is similar to other fuels such as gasoline and diesel. The drawback of these fuels is that they are very expensive to produce, even at very large scales. For example, the Fischer-Tropsch process is presently being developed commercially in Qatar, where a 34,000-barrels-per-day plant is being built to convert natural gas to gasoline using the Fischer-Tropsch process, at an investment of about $100/barrel output-year. Two-thirds of this cost is said to be tied to the methane-reforming process, with only one-third tied to the Fischer-Tropsch reaction itself. This cost does not reflect the cost of the infrastructure for getting the gas to the plant, cleaning it up, or getting the product to market.

One major problem is that the Fischer-Tropsch catalysts are far from perfect (the reaction is not sufficiently selective) and the by-products formed—in particular heavier oils and waxes—require further refining to generate a clean, high-value liquid fuel equivalent to gasoline. The by-product fuel would be best used for small-scale applications such as heating or bunker oil, as upgrading of this fuel for other uses would be costly (Dale Simbeck, SFA Pacific, personal communication, 8 November 2004).

Overall, the large economies of scale required for these processes makes them inapplicable to dairy biogas. Another problem is that parasitic energy requirements cause thermal efficiency (fuel energy out/biogas energy fed) to be lower than for other products such as liquefied natural gas.

More fundamentally, for the Fischer-Tropsch process as well as for methanol production, the optimal process is to react the natural gas with both pure O_2 and steam to get a H_2:CO ratio of 1:2.1 (this is slightly higher than the stoichiometry shown above, to account for hydrocarbon molecule and extra hydrogen). Again, such a process is not applicable for dairy-scale operations due to the high cost of O_2 at such scales. Also the high purity of gas required is an issue for small-scale operations.

The project in Qatar demonstrates that the technology is indeed commercial (even with the almost 50% lower oil prices that prevailed at the time of this investment), but it also points to the need for very large investments to achieve economics of scale. If Fischer-Tropsch technologies were economically viable at a small scale, it is likely they would be marshaled for greater use under the current market conditions of nearly $50/barrel of oil. For example, there is considerable interest in capturing the enormous potential of natural gas that is now being flared worldwide, but the Fischer-Tropsch process has not been attempted for this, to our knowledge. The lack of application of Fischer-Tropsch technologies to these natural gas wells suggests that this technology is not yet suitable for small biogas applications.

Biomethane to Methanol

The conversion of methane to methanol is very similar to, but somewhat easier than, the Fischer-Tropsch process, both in terms of engineering and economic principles and application. An advantage of methanol production is that unwanted by-products are minor compared to Fischer-Tropsch, and the fuel obtained is uniform and more easily recovered and produced. The drawback is that this fuel has very limited demand, particularly now with the phaseout of methyl-tertiary butyl ether (MTBE), a fuel additive introduced in the late 1970s. There are industrial uses for methanol. A potentially expanding market for renewable methanol (biomethanol) is in the production of biodiesel.

A large potential source of biomethanol is from biomass gasification followed by catalytic conversion. Biomass gasification to produce methanol was proposed in the USA during the 1980s and again in the 1990s, when MTBE became an important oxygenated fuel additive. At that time, methanol, an important input to the production of MTBE, sharply increased in price. This economic incentive led several groups to explore the potential of methanol from biogas (see Appendix C for more in-depth discussion of past and present proposed biomethanol projects). Nevertheless, during the past 20 years, no market has developed for methanol as a neat fuel or fuel additive. Methanol has only half the energy content of gasoline; it has a lower vapor pressure than gasoline, it can attack fuel and engine components; and it is toxic. Although these obstacles could be overcome, together with the lack of a methanol vehicle fueling infrastructure, they severely limit the potential of this fuel.

Biogas or Biomethane to Hydrogen Fuel

Perhaps no single fuel has as much promise and presents as many challenging problems as hydrogen. Not surprisingly, there is great interest in the conversion of biogas to hydrogen. However, the only avenue to hydrogen from methane is through the previously discussed gasification/reform and shift reactions, in which CO and H_2 are produced from CH_4, and the CO along with H_2O is converted to H_2 and CO_2. Converting CH_4 to H_2 is not a major challenge, technically, and might even be feasible on somewhat modest scales. Several companies claim to have small-scale methane reformers that can accomplish this, but nothing has yet materialized. (However, Exxon-Mobil is expected to announce a new reformer for on-board conversion of fuels to H_2 in the near future.)

Once H_2 is produced, it could be used for fuel cells in cars or for stationary applications. The latter, however, are of limited interest for small-scale conversion facilities (and electricity can be produced from biogas without the highly expensive and overall inefficient routing through H_2 and then fuel cells).

One critical issue is the high degree of clean-up required before H_2 can be used in fuel cells. The very high purity of H_2 required makes applications to small-scale biogas operations problematic. Although iron sponge and other H_2S removal systems can be highly effective, even occasional breakthroughs or accidents would be catastrophic for fuel cell applications.

Carbon monoxide (CO) is another contaminant that has to be reduced to very low levels. The shift reaction using pressure swing absorption to remove CO can produce high purity H_2; however, the blow-down stream loses 10% or more of the fuel input. In large plants this can be used for process heat; in smaller plants such use is more limited. Thus, the net efficiency of a reformer-shift reactor train is estimated at 75% for large installations and 60% for smaller ones. In this context, small refers to plants that produce at least 1 million scf of methane per day, which is equivalent to over 30,000 cows.[2] For a dairy manure facility with 5,000 cows, the best likely net efficiency would be around 50%. This does not consider parasitic energy requirements, which, again, can be high at small scales.

At present and for the foreseeable future, the real limitation of biogas-to-CH_4-to-H_2 conversion systems is the undeveloped nature of the technology, from production to storage to use. This is illustrated from the recent opening in Washington D.C. of the first H_2 fueling station, which uses liquid H_2, not on-site reformed H_2. Based on efficiency alone, conversion of biogas to biomethane to H_2 is perhaps the least favorable option for upgrading biogas.

Converting Biomethane to Liquefied Biomethane

Theoretically, biomethane from biogas can be liquefied to a fuel similar to LNG, which we call liquefied biomethane (LBM) in this report. This requires a combination of high pressures and low temperatures, and is a rather energy intensive and expensive process. However, emerging technologies developed in the last five years have highlighted better opportunities for LBM technologies. The advantages of LBM over CBM is a much higher energy content per volume, about 84,000 Btu/gallon or about 70% that of gasoline. If the energy required for liquefaction is ignored, 1,000 scf of CH_4 will yield about 12 gallons of LBM (if included, the yield is about 10 gallons/1,000 scf). Thus, assuming 10% losses and a separate source for electricity, a 1,500-cow dairy farm, producing about 70,000 ft^3 per day of biogas (45,000 ft^3/day of CH_4) could generate roughly 500 gallons of LBM/day.

However, as with other biogas upgrading options, there are a number of constraints on the conversion of biogas to LBM. First, the biogas needs to be meticulously purified, as even slight impurities (H_2O or CO_2) can cause significant problems during the liquefaction process (e.g., deposits on heat exchange surfaces, clogging of piping, etc.). Inclusion of air must be carefully avoided, as entrained O_2 would create danger of explosions (which is perhaps more of a problem with landfill gas, where air entrainment is common). Until quite recently, the capital and operating costs of the compression and liquefaction technology have been quite scale sensitive, with trade-offs between efficiency and costs.

[2] There are actually quite a number of small plants that convert methane (natural gas) to H_2 for industrial applications, primarily for use in refineries to remove H_2S and to clean up gasoline and diesel fuel. Typically, these systems have high available pressure and high purity natural gas and the product, H_2, has higher value as a chemical than it does as fuel.

Although large, centrally located LNG facilities are more economical in most respects than small dispersed production, small facilities do not have the added costs of distribution, storage, and associated losses, which can be significant for LNG. Many “stranded” natural gas wells and fields that are not serviced by pipelines would seem to be appropriate for the use of small-scale LNG production, which would allow the recovery natural gas that is currently flared. However, at the present time in California, only a single experimental Pacific Gas and Electric Company (PG&E) plant produces LNG, and this plant uses non-biomass sources for LNG production. All other LNG is imported from out-of-state, particularly from Arizona. This would seem to argue against the viability of small-scale production of LBM (or LNG) at present.

Several small-scale methane liquefaction technologies have been developed over the years. These include the following:

- *Anker-Gram liquefier*. More than 30 years ago, a Vancouver, Canada, company developed a 500-gpd system called the Anker-Gram liquefier for small-scale production of LNG for fueling vehicles. Although it is no longer in use, the technology (and, apparently the prototype liquefier unit itself) passed through many companies and traveled to many continents (North America, Australia, South America) over the years, demonstrating the feasibility of the technology along the way. It failed in the hands of Ecogas in Houston, Texas, because the “feedgas pressure was lower and CO_2 content higher than the liquefier was designed for.” Powers and Pope (2002) state that this liquefier was “noteworthy because it is the only small liquefier that we know that has ever operated routinely to provide fuel for an LNG fleet.”
- *Other relatively small units* (1,500 to 5,000 gpd from natural gas) have also been developed and tested in California. Liberty Fuels, Inc. had a liquefier proposed for use in the 250-to-2,000 gpd range, with a projected cost of $420,000 for operations of 1,000 gpd. However, only a 50-gpd pilot-scale unit was built. Powers and Pope (2002) state that “The liquefier is no longer in operation and it is unclear if Liberty fuels is still actively promoting onsite liquefiers and fueling stations at this time.” More recently, the California Energy Commission (CEC) has supported development and demonstration of small-scale liquefaction units that could be used at stranded gas wells and landfill gas and could also be considered for dairy manure biogas.
- *A process developed by the Gas Technology Institute* (GTI) to produce 1,000 gpd of LNG from biogas or digester gas uses off-the-shelf components and has a purchase price of $150,000. Two important reservations are that the equipment purchase cost does not include gas cleanup cost and is only suitable for pipeline gas. If installation and cleanup are included, it is estimated by the project team that a system producing 1,000 gpd LNG would probably cost in the range of $500,000 to $1 million (Wegryzn, 2004)
- *A process attempted by Cryofuels, Incorporated* (Monroe, Washington) was supported at the Hartland Landfill in British Columbia. Problems were encountered with CO_2 freezeout, and the unit, despite later participation by Applied LNG technology, Inc. was ultimately shut down for lack of funding (Powers and Pope, 2002).

Despite its problems, the most apparently relevant project is that of CryoFuel Systems, Inc., of Monroe, Washington. In partnership with Applied LNG Technologies (ALT) a natural gas company, CryoFuel demonstrated a skid-mounted, 225-gpd liquefaction system at the Hartland

Road Landfill in Victoria, BC (Canada). The unit, shown in Figure 3-7, was reported to include a gas purification system (condenser and activated carbon unit) and CO_2 removal in dual-freezing heat exchangers followed by a temperature-swing absorber bed. The company has announced several projects for applying this process, including one in Kern County and one near Stockton, for both landfill gas and stranded gas wells. The Stockton project is said to have produced over 5,000 gallons of LNG per day beginning in 2003, but verification of actual long-term performance is lacking (Powers and Pope, 2002).

This recent activity indicates that technology for liquefaction is becoming more cost-effective Also, much of the lack of progress or success has been due to oil prices that were, until recently, low even in comparison to earlier inflation-adjusted prices. Now that oil prices have reached new

Figure 3-7 Skid-mounted 225-gpd landfill gas liquefaction Hartland Unit, located in Victoria, B.C. developed by CryoFuels Systems, Inc. (source: CryoFuels Systems, undated)

heights, continued improvements in this technology are likely. Carefully engineered demonstration projects can help achieve such advances.

Even so, the economics of the entire package (digester, LBM production unit, storage-fueling system, and vehicular modifications) would need to be investigated in some detail. From this initial review, however, liquefaction appears to be the most promising use for biogas. One of the advantages of LBM is that it is more easily distributed (via cryogenic tankers) than CBM, as discussed in Chapter 4. Although liquefaction is more challenging and expensive from a technological perspective than compression, it results in a more usable and more transportable product.

4. Storage and Transportation of Biogas and Biomethane

Dairy manure biogas is generally used in combined heat and power applications (CHP) that combust the biogas to generate electricity and heat for on-farm use. The electricity is typically produced directly from the biogas as it is created, although the biogas may be stored for later use when applications require variable power or when production is greater than consumption.

Biogas that has been upgraded to biomethane by removing the H_2S, moisture, and CO_2 can be used as a vehicular fuel. Since production of such fuel typically exceeds immediate on-site demand, the biomethane must be stored for future use, usually either as compressed biomethane (CBM) or liquefied biomethane (LBM). Because most farms will produce more biomethane than they can use on-site, the excess biomethane must be transported to a location where it can be used or further distributed.

This chapter discusses the types of systems available for the storage of biogas and/or biomethane as well as modes of biomethane transportation.

Storage Systems and Costs

There are two basic reasons for storing biogas or biomethane: storage for later on-site usage and storage before and/or after transportation to off-site distribution points or systems. The least expensive and easiest to use storage systems for on-farm applications are low-pressure systems; these systems are commonly used for on-site, intermediate storage of biogas. The energy, safety, and scrubbing requirements of medium- and high-pressure storage systems make them costly and high-maintenance options for on-farm use. Such extra costs can be best justified for biomethane, which has a higher heat content and is therefore a more valuable fuel than biogas.

Table 4-1 summarizes on-farm storage options for biogas and biomethane. These options are discussed in more detail below.

Table 4-1 On-Farm Storage Options for Biogas and Biomethane

Purpose of Storage	Pressure (psi)	Storage Device	Material	Size (ft^3)
Short and intermediate storage for on-farm use (currently used on farms for biogas storage)	< 0.1	Floating Cover	Reinforced and non-reinforced plastics, rubbers	Variable volume usually less than one day's production
	<2	Gas bag	Reinforced and non-reinforced plastics, rubbers	150 – 11,000
	2 – 6	Water sealed gas holder	Steel	3,500
		Weighted gas bag	Reinforced and non-reinforced plastics, rubbers	880 – 28,000
		Floating roof	Plastic, reinforced plastic	Variable volume, usually less than one day's production
Possible means of storage for later on- or off-farm use (could be used for biomethane)	10 – 2,900	Propane or butane tanks	Steel	2,000
	>2,900	Commercial gas cylinders	Alloy steel	350

Source: Ross et al., 1996.

psi = Pounds per square inch, ambient conditions ft^3 = Cubic feet

Biogas Storage

Both biogas and biomethane can be stored for on-farm uses. In practice, however, most biogas is used as it is produced. Thus, the need for biogas storage is usually of a temporary nature, at times when production exceeds consumption or during maintenance of digester equipment. Important considerations for on-farm storage of biogas include (1) the needed volume (typically, only small amounts of biogas need to be stored at any one time), (2) possible corrosion from H_2S or water vapor that may be present, even if the gas has been partially cleaned, and (3) cost (since biogas is a relatively low-value fuel).

Low-Pressure Storage of Biogas

Floating gas holders on the digester form a low-pressure storage option for biogas systems. These systems typically operate at pressures up to 10-inch water column (less than 2 psi). Floating gas holders can be made of steel, fiberglass, or a flexible fabric. A separate tank may be used with a floating gas holder for the storage of the digestate and also storage of the raw biogas.

One advantage of a digester with an integral gas storage component is the reduced capital cost of the system. The least expensive and most trouble-free gas holder is the flexible inflatable fabric top, as it does not react with the H_2S in the biogas and is integral to the digester. These types of covers are often used with plug-flow and complete-mix digesters (see Chapter 2). Flexible membrane materials commonly used for these gas holders include high-density polyethylene (HDPE), low-density polyethylene (LDPE), linear low density polyethylene (LLDPE), and chlorosulfonated polyethylene covered polyester (such as Hypalon®, a registered product of DuPont Dow Elastomers L.L.C.). Thicknesses for cover materials typically vary from 18 to 100 mils (0.5 to 2.5 millimeters) (Ross, et al., 1996, p. 5-15). In addition, gas bags of varying sizes are available and can be added to the system. These bags are manufactured from the same materials mentioned above and may be protected from puncture damage by installing them as liners for steel or concrete tanks.

Medium-Pressure Storage of Cleaned Biogas

Biogas can also be stored at medium pressure between 2 and 200 psi, although this is rarely, if ever done, in the USA. To prevent corrosion of the tank components and to ensure safe operation, the biogas must first be cleaned by removing H_2S. Next, the cleaned biogas must be slightly compressed prior to storage in tanks. Typical propane gas tanks are rated to 250 psi. Compressing biogas to this pressure range uses about 5 kWh per 1,000 ft^3 (Ross, et al., 1996, p. 5-18). Assuming the biogas is 60% methane and a heat rate of 13,600 Btu/kWh, the energy needed for compression is approximately 10% of the energy content of the stored biogas.

Biomethane Storage

Biomethane is less corrosive than biogas and also is potentially more valuable as a fuel. For these reasons, it may be both possible and desirable to store biomethane for on- or off-farm uses.

High-Pressure Storage of Compressed Biomethane

Biomethane can be stored as CBM to save space. Gas scrubbing is even more important at high pressures because impurities such as H_2S and water are very likely to condense and cause corrosion. The gas is stored in steel cylinders such as those typically used for storage of other commercial gases. Storage facilities must be adequately fitted with safety devices such as rupture disks and pressure relief valves. The cost of compressing gas to high pressures between 2,000 and 5,000 psi is much greater than the cost of compressing gas for medium-pressure storage. Because of these high costs, the biogas is typically upgraded to biomethane, a more valuable product, prior to compression. Compression to 2,000 psi requires nearly 14 kWh per 1,000 ft of biomethane (Ross et al., 1996, pp 5-19). If the biogas is upgraded to 97% methane and the assumed heat rate is 12,000 Btu/kWh, the energy needed for compression amounts to 17% of the energy content of the gas.

The main components of an example on-farm CBM storage system are shown in Figure 4-1.

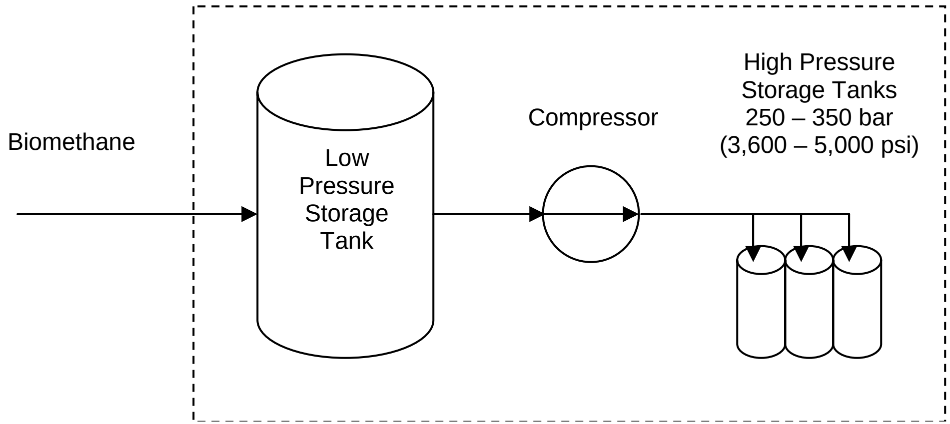

Figure 4-1 Schematic of on-farm storage system for compressed biomethane

The low-pressure storage tank is a buffer for the output from the biogas upgrading equipment. The tank would most likely consist of one or two large, air-tight vessels with sufficient storage capacity for around one to two days worth of biogas production. For example, a dairy with 1,000 cows would yield approximately 30,000 ft^3 biomethane/day. Note that by compressing the biomethane slightly, the amount of gas stored in the low-pressure storage tank can be increased proportionately[1]. Large, stationary low-pressure storage tanks suitable for this application are typically custom designed and are available from many manufacturers.

Because it is highly unlikely that there would be sufficient on-farm vehicle demand for all of the biomethane that a farm could produce, most or all of the biomethane must eventually be transported to a refueling station. Biomethane has an inherently low energy density at atmospheric pressure; therefore, the most economical and efficient way to transport upgraded biogas over the road is in compressed form. (Pipeline distribution of biomethane is discussed in a later section.) Since CNG refueling stations normally provide CNG at 3,000 to 3,600 psi, CBM would be transported at similar or higher pressures to minimize the need for additional compression at the refueling station.

The compressor receives the low-pressure biomethane from the storage tank and compresses it to 3,600 to 5,000 psi. The compressor should be specified to handle the output flow rate from the

[1] According to Boyle’s Law, pressure (P) is inversely proportional to volume (V) for an ideal gas assuming temperature and the amount of gas are held constant, i.e., P x V = constant.

biogas upgrading equipment. For example, a dairy with 1,000 cows would yield a flow rate of approximately 2,000 ft^3 raw biogas/hour. There are several manufacturers of commercially available compressors in this range (e.g., Bauer Compressors and GreenField Compression).

The CBM output of the compressor is fed to a number of individual high-pressure storage tanks connected in parallel and housed in a portable trailer. (In the case of on-farm CBM refueling, the high-pressure storage tanks could be stationary and potentially much larger.) Portable high-pressure storage tanks rated for this type of application are commercially available from a variety of manufacturers (e.g., Dynetek Industries and General Dynamics).

Storage of Liquefied Biomethane

Biomethane can also be liquefied, creating a product known as liquefied biomethane (LBM). Two of the main advantages of LBM are that it can be transported relatively easily and it can be dispensed to either LNG vehicles or CNG vehicles (the latter is made possible through a liquid-to-compressed natural gas (LCNG) refueling station equipment which creates CNG from LNG feedstock). However, if LBM is to be used off-farm, it must transported by tanker trucks, which normally have a 10,000-gallon capacity. For obvious economic reasons, the LBM must be stored on-farm until 10,000 gallons have accumulated.

Figure 4-2 shows the generalized process of storing LBM prior to use or transport. The low-pressure storage tank is a buffer for LBM after it exits the biomethane liquefaction equipment. Typical LNG storage tanks are double-walled, thermally insulated vessels with storage capacities of 15,000 gallons for stationary, aboveground applications. (Smaller LNG storage tanks with 6,000-gallon storage capacities are also available, but would only be useful for on-farm applications, and the on-farm demand for LBM is likely to be relatively low.) For a dairy with 1,000 cows, 15,000 gallons is equivalent to approximately six weeks' worth of LBM production. The LBM output of the biogas liquefaction equipment is nominally at 50 psi, which is also the nominal pressure of the LBM in the low-pressure storage tank. LNG storage tanks are available from several companies specializing in LNG equipment (e.g., NexGen Fueling). The typical cost for a 15,000-gallon tank is $170,000.

Since it is highly unlikely that on-farm vehicle demand will consume all of the LBM produced (see Chapter 5), most or all of the LBM must be transported to a refueling station where it can be dispensed to natural-gas fueled vehicles. Liquid biomethane is transported in the same manner as LNG, that is, via insulated tanker trucks designed for transportation of cryogenic liquids. Standard tanker trucks hold 10,000 gallons of LNG or LBM at approximately 50 psi.

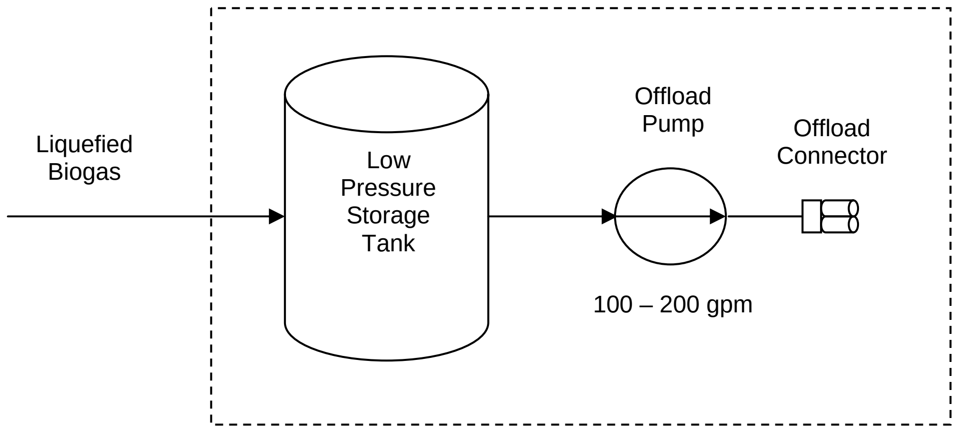

Figure 4-2 Schematic of storage system for liquefied biomethane

An offload pump is needed to pump the LBM from the low-pressure storage tank to the tanker truck (Figure 4-2). Typical flow rates for these types of pumps are 100 to 200 gallons per minute (gpm). Cryogenic pumps for this type of application are available from a variety of manufacturers and typically cost between $15,000 to 25,000. The offload connector is a standard LNG interface connector and is normally included as part of the offload pump.

One of the main disadvantages of LNG and thus LBM is that the cryogenic liquid will heat up during storage, which will result in loss of LBM to evaporation through a release valve on the tank. To minimize these losses, LBM should be used fairly quickly after production. It is generally recommended that LBM be stored for no more than a week before it is either used or transported to a fueling station. Storage for a longer period will result in an economically unacceptable level of evaporative loss. Since standard LNG tankers carry about 10,000 gallons, a small-scale liquefaction facility should produce at least 3,000 gallons of LBM per day. However, the production of this much LBM requires approximately 8,000 cows—which could only be found at an extremely large dairy or a central digester facility.

Distribution of Biomethane

Biogas is a low-grade, low-value fuel and therefore it is not economically feasible to transport it for any distance (although there are two locations in California where it is sent through a 1- or 2-mile pipeline to a generator). Likewise, biogas cannot be economically trucked.

In contrast, biomethane can be distributed to its ultimate point of consumption by one of several options, depending on its point of origin:

- Distribution via dedicated biomethane pipelines
- Distribution via the natural gas pipeline
- Over-the road transport of CBM
- Over-the-road transport of LBM

Distribution via Dedicated Biomethane Pipelines

If the point of consumption is relatively close to the point of production (e.g., less than 1 mile), the biomethane would typically be distributed via dedicated biogas pipelines (buried or aboveground). For example, biomethane intended for use as CNG vehicle fuel could be transported via dedicated pipelines to a CNG refueling station. For short distances over privately owned property where easements are not required, this is usually the most cost-effective method. Costs for laying dedicated biomethane pipelines can vary greatly, and may range from about $100,000 to $250,000 or more per mile. Note that biomethane distributed via dedicated biomethane pipelines must compete with natural gas prices in the marketplace.

Distribution via the Natural Gas Pipeline Network

The natural gas pipeline network offers a potentially unlimited storage and distribution system for biomethane. Since the natural gas pipelines are typically owned by either private or municipal gas utilities, the biomethane producer must negotiate an agreement with the pipeline owner (i.e., the local gas utility) to supply biomethane into the natural gas pipelines. One prerequisite for such an agreement would be to ensure that biomethane injected into the natural gas pipeline network meets the local gas utility's pipeline gas quality (e.g., gas composition) standards. Once the biomethane is injected into the natural gas pipeline network, it can be used as a direct substitute for natural gas by any piece of equipment connected to the natural gas grid, including domestic gas appliances, commercial/industrial gas equipment, and CNG refueling stations.

As mentioned, any gas (including biomethane) transported via the natural gas pipeline network is required to meet the local gas company gas quality standards set by the owner of the natural gas pipeline network. In California, the two major private natural gas pipeline distribution networks are owned by PG&E and Southern California Gas Company (SoCalGas); these networks provide natural gas for most of northern and southern California, respectively. In addition to PG&E and SoCalGas, there are a number of municipal gas utilities throughout the state which own and operate their own natural gas pipeline distribution networks. Default gas quality and interchangeability requirements for the two networks are set forth in PG&E's Rule 21 and SoCalGas's Rule 30 (although these requirements may be superseded by specific agreements).

In reality, there is likely to be significant resistance by the local gas utility toward attempts to distribute biomethane via the natural gas pipeline network. One reason for this resistance is the justifiable concern that poor gas quality might have potentially devastating effects on gas equipment. As a result, there are likely to be severe requirements for gas quality monitoring and fail-safe disconnection of the biomethane supply from the natural gas pipeline network, which may lead to prohibitively high costs for biomethane producers. In addition, biomethane distributed via the natural gas pipeline network would probably be sold to the local gas utility and therefore must compete with the wholesale price of natural gas offered by other natural gas suppliers, though it might be possible to wheel the gas to an industrial user at a negotiated price.

As of 2005, the only location in the USA where biomethane is sold to a gas utility as a supplemental equivalent for natural gas is the King County South Wastewater Treatment Plant in Renton, Washington. This plant includes an anaerobic digester and water scrubbing unit that produce pipeline quality biomethane. The biomethane is sold to the local gas utility, Puget Sound Energy, which in turn resells the biomethane to its natural gas customers. Local circumstances support this scenario: electric power is extremely cheap in the Seattle area ($0.025 to $0.03/kWh), and thus the biomethane produced by the Renton plant is more valuable than the electric power that could have been produced by the biogas. In California, where electric power costs are currently much higher (e.g., 0.08 to $0.10/kWh), it would be more economical to generate electric power from the biogas rather than upgrade it to biomethane.

Over-the-Road Transportation of Compressed Biomethane

If distribution of biomethane via dedicated pipelines or the natural gas grid is impractical or prohibitively expensive, over-the-road transportation of compressed biomethane may be a distribution option. The energy density of biomethane is extremely low at ambient pressure and as a result it must be compressed to relatively high pressures (e.g., 3,000 to 3,600 psi) to transport economically in over-the-road vehicles.

Compressed natural gas bulk transport vehicles, often referred to as “tube trailers,” are used when over-the-road transportation of CNG or compressed biomethane is required. U.S. Department of Transportation (DOT) regulations classify CNG as a Class 2 (gas), Division 2.1 (flammable) hazardous material; it is assumed that over-the-road transportation of compressed biomethane would be held to the same requirements. Major requirements include the following:

- Transportation in DOT-approved tanks (e.g., DOT-3AAX seamless steel cylinders) that do not exceed the rated tank pressure
- Water vapor content of less than 0.5 lbs/million scf (i.e., less than 10 ppm H_2O)
- Minimum methane content of 98%
- Appropriate hazardous materials markings

Given the transportation and capital equipment costs associated with over-the-road transportation of compressed biomethane as well as the probable need for additional compression at the point of consumption, this method of biomethane distribution is generally not considered a long-term, cost-effective solution. Rather it is used as a temporary solution in certain situations, for example, as a means of expanding the use of compressed biomethane vehicle fuel into a new market prior to the installation of permanent refueling infrastructure.

Over-the-Road Transportation of Liquefied Biomethane

Over-the-road transportation of liquefied biomethane is a potential way of addressing many of the infrastructure issues associated with biomethane distribution; however, this distribution method presents additional technical challenges. Bulk LNG is transported in LNG tankers. These are typically class 8 vehicles consisting of a tractor towing a 10,000-gallon LNG tanker. Liquid natural gas is transported at relatively low pressures (e.g., 20 to 150 psi), but because it is a cryogenic liquid (i.e., its nominal temperature is -260º F), it requires special handling. U.S. DOT regulations classify LNG as a Class 2 (gas), Division 2.1 (flammable) hazardous material; it is assumed that over-the-road transportation of liquefied biomethane will be held to the same requirements:

- Transportation in DOT-approved tanks (e.g., double-walled insulated steel tanks)
- Presence of two independent pressure relief systems
- Maximum one-way-travel-time marking
- Appropriate hazardous materials markings

One of the most attractive features of over-the-road transportation of liquefied biomethane is that an infrastructure and market already exist. (In addition to acting as a fuel for LNG vehicles, liquefied biomethane can also be used to provide fuel for CNG vehicles via LCNG refueling stations which turn LNG into CNG.) In California, where almost all LNG is currently imported from other states, in-state production of LBM would gain a competitive advantage over LNG with respect to transportation costs. While liquefaction of landfill gas has been demonstrated at a number of locations throughout the USA, this technology has never been applied to biomethane produced from dairy manure or similar feedstocks.

As noted, a significant disadvantage of LBM is that it must be used fairly quickly after it is produced (typically within one week) to avoid significant fuel losses from thermal evaporation. Since standard LNG tankers carry about 10,000 gallons of LNG, a small-scale LNG liquefaction facility should produce about 3,000 gallons of liquefied biomethane/day. This would allow a full LNG tanker to be loaded approximately every four days for cost-effective distribution to the ultimate point of consumption.

5. Potential Uses of Biogas and Biomethane

This chapter discusses the potential uses of biogas and biomethane. At present, dairy manure biogas is used on-farm for direct electricity generation and some of the waste heat is recovered for other uses. One of our goals was to explore alternative direct on-farm uses of raw and slightly cleaned biogas. Because of its highly corrosive nature (due to the presence of H_2S and water) and its low energy density (as obtained from the digester, biogas contains only about 80 Btu/gallon or 600 Btu/scf, the potential for off-farm use of biogas is extremely low. As a result, this chapter focuses on possible alternate on-farm uses of biogas.

This chapter also explores potential on- and off-farm uses of biomethane—dairy biogas that has been upgraded through the removal of CO_2, H_2S, and water. Biomethane contains a heat capacity of about 130 Btu/gallon, which is equivalent to about 1,000 Btu/scf. Because of this high energy content, biomethane could be sold for off-farm applications to industrial or commercial users, for injection into a natural gas pipeline, or as vehicular fuel.

Potential On-Farm Uses of Biogas

The most common and popular on-farm use of biogas is to fuel an engine-generator (generator-set or genset) to produce electricity for on-farm use, or, less commonly, for off-farm sale or under a net-metered arrangement with the utility. Heat recovered from combustion of the biogas (whether in boilers or internal combustion engines) can be used to maintain the operating temperature of the anaerobic digester or for other on-farm uses. Because of relatively low energy prices in the past, other on-farm uses of biogas have been minimal and the associated experience base is quite small. Recent increases in energy prices and the likelihood of continued high prices may increase the attractiveness of other on-farm uses. More development work and analysis is needed, however, particularly with regard to USA-specific issues (as opposed to somewhat more favorable i.e., subsidized situations in Europe).

Biogas could be used for the same applications off-farm; however, as discussed in Chapter 4, off-farm distribution of biogas is constrained by factors such as economics and corrosion of transporting equipment.

In the following sections, we discuss some of the general considerations related to the use of biogas as a direct on-farm fuel. Although many of these considerations pertain to combined heat and power (CHP) applications, they provide important background information for possible alternative uses of biogas.

We also consider specific alternative on-farm uses, including as fuel for irrigation pumps and refrigeration systems. Finally, we discuss practical (non-technical) factors that affect the viability of biogas as a fuel for alternate on-farm use such as how well production capacity is matched to on-farm demand.

Biogas as a Fuel for Combined Heat and Power Applications

Burners and boilers used to produce heat and steam can be fueled by biogas. The direct substitution of biogas for natural gas or LPG, however, will not work for most standard commercially available burners. At given fuel gas feed pressures, gas must flow into combustion in the right stoichiometric ratio with air. Because of its high CO_2 content, if biogas flows through the burner orifice at the pressure intended for feeding methane or propane, the fuel-to-air ratio is insufficient to ensure flame stability.

A relatively simple option is to provide the combustion equipment with a second "as is" biogas burner that operates in parallel with the first. In this case, regardless of the fuel used, air flow is kept constant. Burner orifices for the respective burners can be set such that each burner meters the proper amount of gas to meet combustion stoichiometry. This could require other control measures such as (for simplest control) complete switchovers from pure biogas fuel to the fossil alternative, and modest (a few hours' worth) backup biogas storage, but is otherwise straightforward.

Some operations that use landfill gas have adapted standard equipment to allow easy switchover from different fuel sources, whether landfill biogas, natural gas, or oil. An example of such equipment is the Cleaver-Brooks boiler at the Ajinomoto Pharmaceutical plant in Raleigh North Carolina, which has operated successfully using landfill gas for more than 10 years (Augenstein and Pacey, 1992; US EPA, 2001).

Conversion of a boiler system to operate on biogas typically involves the enlargement of the fuel orifice and a restriction of the air intake. Important considerations include the capability of the combustor to handle the increased volumetric throughput of the lower-Btu biogas, flame stability, and the corrosive impact of raw biogas on the burner equipment.

To prevent corrosion from H_2S and water vapor, operating temperatures should be maintained above the dew point temperature (250° F) to prevent condensation. It may also be advisable to use propane or natural gas for start up and shut down of the system, since higher operating temperatures cannot be maintained at these times.

If the biogas has an energy content lower than 400 Btu/scf, the combustion system may be limited by the volumetric throughput of the fuel, which may result in de-rating of the equipment. In addition, the burner orifice should be enlarged to prevent a higher pressure drop across the burner orifice due to the decreased heating value and specific gravity of the biogas results. However, orifice enlargement will degrade the performance of the burner if it is ever operated on natural gas or propane. To resolve this problem, the propane or natural gas can be mixed with air to create an input fuel with an equivalent pressure drop and heat input as the biogas. It is also possible to achieve fuel flexibility by using a dual burner system, as mentioned above. This allows optimum performance of the burners since they maintain the pressure drop for each fuel independently.

Direct Use of Biogas for On-Farm Heating

The need for on-farm heating applications varies both seasonally and from farm to farm. All farms require hot water on a year-round basis, although for most, the amount needed is likely to be far less than what could be generated from the biogas production of an average farm. In California, the need to heat buildings is seasonal, with the exception of nursery and hog farrowing rooms, which may require some year-round heat. Depending on the type of anaerobic digester used, some heat may be needed to keep the digester system at the proper operating temperature. There are three common technologies that can be used to supply heat for these types of applications: hot water boilers, forced-air heat, and direct-fired heat.

Hot water boilers. A modified commercial cast-iron natural-gas boiler can be used to produce hot water for most on-farm applications. Modifications include adjustments to the air-fuel mixture and enlargement of the burner jets. All metal surfaces of the housing should be painted. Flame-tube boilers may be used if the exhaust temperature is maintained above 300° F to minimize condensation. The high concentration of H_2S in the gas may result in clogging of the flame tubes.

The typical capacities, efficiencies, controls, and operating schemes for on-farm hot water boilers are provided below:

- *Available capacities*: Cast-iron pot boilers are available in sizes from 45,000 Btu/hr and larger.
- *Thermal efficiencies*: Conversion efficiencies are 75% to 85%.
- *Control systems*: Typical commercial control systems supplied with boilers.
- *Operating schemes*: The boiler could be used to produce all the heat required for an anaerobic digester (if a heated digester is used) as well as the maximum on-farm demand for heat.

Forced-air furnaces. Hot-air furnaces can be fueled by surplus biogas from a covered lagoon; however, California farms generally do not have a year-round need for heat. Forced air furnaces are manufactured from thin metal and depend on metal-to-air heat exchange. Corrosion-resistant models are not available; therefore, the gas should be pretreated to remove H_2S and water.

The typical capacities, efficiencies, controls, and operating schemes for on-farm forced-air furnaces are provided below:

Available capacities: Forced air furnaces are made with capacities from 40,000 Btu/hr and up.

Thermal efficiencies: Conversion efficiencies are 75% to 85%.

Control systems: Typical commercial control systems supplied with furnaces are used for control.

Operating schemes: It is difficult to recover heat for digester heating from a hot air furnace, and because of the seasonal need for other types of heating, it would be unusual in California to find a use for forced hot air on a farm that could consume all of the available biogas production potential. On the positive side, this type of heat would produce few environmental impacts if a California-approved low-NO_x-emission furnace were used. Gas treatment to remove H_2S would also reduce potential SO_2 emissions.

Direct-fired room heaters. Direct-fired heating is commonly used in hog farrowing and nursery rooms. A farm will typically have multiple units and some heat is required virtually every day of the year. Commercial models of this equipment can be operated using treated biogas. Burner orifices should be enlarged for low Btu gas.

A direct-fired heater can be fueled by surplus biogas or by biogas from a covered lagoon. Biogas would be burned directly in the room for heat; therefore, the biogas would need to be treated to remove H_2S and water.

The typical capacities, efficiencies, controls, and operating schemes for on-farm direct-fired heat are provided below:

- *Available capacities*: Direct-fired room heaters are available in a wide range of sizes, ranging from 40,000 Btu/h and upward.
- *Thermal efficiencies*: Conversion efficiencies are generally 85% to 90%, as all gas is burned in the room.
- *Control systems*: Typical commercial control systems supplied with these units can be used.
- *Operating schemes*: It is difficult to recover heat for digester heating from a direct-fired room heater. The operating scheme would depend upon the balance of biogas supply and maximum demand of installed heaters. Biogas could be supplied to as many heaters as the winter gas production could support. However, seasonal daily heat demand would likely be less than the production potential and, therefore, a portion of the collected gas would likely be wasted. Most direct-fired room heaters are of too small a capacity to be covered by air pollution regulations, but treatment of the gas to eliminate H_2S would eliminate potential SO_2 emissions.

Biogas as an Engine Fuel

Electricity generation using biogas on dairy farms is a commercially available, proven technology. Typical installations use spark-ignited natural gas or propane engines that have been modified to operate on biogas. Biogas-fueled engines could also be used for other on-farm applications.

As discussed below, diesel or gasoline engines can be modified to use biogas. Potentially, the more efficient Stirling engines could also be operated on biogas. Although waste heat from engine operations is used frequently in CHP applications, it is probably not practical to recover the small amounts of heat generated by engines used directly for specific uses such as irrigation or refrigeration.

Internal combustion engines. Natural gas or propane engines (typically used for electricity generation) can be converted to burn treated biogas by (1) modifying carburetion to accommodate the lower volumetric heating value of the biogas (400-600 Btu/scf) compared to natural gas (1,000 Btu/scf) and (2) adjusting the timing on the spark to accommodate the slower flame velocity of biogas ignition systems. Gas treatment to prevent corrosion from H_2S is usually not necessary if care is taken with engine selection and proper maintenance procedures are followed. According to RCM Digesters, natural gas or propane engines operating on raw biogas should have an accelerated oil change schedule. Typically, oil changes are recommended every 600 hours for a natural gas engine. When operating on raw biogas, oil changes should be conducted every 300 hours.

Biogas can fuel engine-driven refrigeration compressor and irrigation pumps. Spark ignited gasoline engines may be converted to operate on biogas by changing the carburetor to one that operates on gaseous fuels. However, gas treatment may be necessary depending on the type of engine used. The inherent variable speed operation of a gasoline engine optimizes energy use by closely following the load profile of the compressor. Diesel engines can also be modified to operate on biogas in two ways: (1) by replacing the fuel injectors with spark plugs and replacing the fuel pump with a gas carburetor, and (2) by using diesel fuel for ignition and adding a carburetor for the biogas as well as advancing the ignition timing. The high compression ratio of a diesel engine (16:1) lends itself to operation on biogas. Spark-ignited gas engines tend to operate in the lower 7:1 to 11:1 range of compression ratios, whereas biogas engines ideally operate in the 11:1 to 16:1 range.

The metallurgy of the engine is a critical consideration if raw (digester) biogas is used. The presence of H_2S in the raw biogas may lead to the formation of sulfuric acids, which can result in bearing failures and damage to the piston heads and cylinder sleeves. Copper alloy wrist pins and bearings make engines particularly susceptible to corrosion damage. RCM Digesters has had positive experiences with both Waukesha and Caterpillar engines with regard to their metallurgical resistance to corrosion. To minimize condensation of acid fumes in the crank case, engine manufacturers recommend maintaining engine coolant temperatures above 190° F (Ross, et al., 1996).

Engine manufacturers also use positive crankcase ventilation filters to purge moisture and contaminant-laden gas from the crankcase.

Although biogas is not commonly used as a fuel for gasoline-fuel or diesel-fuel engines, this may change. Below is a synopsis of the typical capacities, controls, and maintenance schedules for on-farm natural gas or propane engines suitable for biogas use... More detail about gasoline and diesel engines for non-electrical generation is given in later sections of this chapter.

Available capacities: Natural gas engines suitable for on-farm biogas utilization range in capacity from 40 to 250 kW.

- *Thermal and electrical efficiencies*: A biogas-fueled engine-generator will normally convert 18% to 25% of the biogas thermal capacity (Btu) to electricity. Because of the lower energy content per unit volume of biogas as compared to diesel or natural gas, engines converted to biogas will be de-rated with respect to their rated power output for other fuels. This de-rating may be as much as 20% of the output rating when the engine is fueled by natural gas.
- *Control systems*: Commercial control systems for engine-generators are well-developed. In the harsh on-farm operating environment, excess automation often fails where simple manual and mechanical controls succeed.
- *Operation and maintenance*: The engine manufacturer should supply an operation and maintenance schedule. A biogas engine should be inspected daily for adequate coolant and lubricant. Oil should be changed regularly to protect the engine. RCM Digesters recommends an accelerated oil change schedule (once every 300 operating hours) for engines that operate using raw biogas. This enables capture and removal of the H_2S in the spent oil, and has resulted in successful operation of a Caterpillar 3306 engine at Langerwerf Dairy for 45,000 hours between major overhauls.

All engine mechanical safety devices should be checked monthly for proper function. Other engine components such as spark plugs require maintenance on a monthly to yearly basis. Normal engine wear requires valve jobs every 6 to 24 months and engine rebuilding or replacement every 2 to 4 years. Engine controls require periodic repair or replacement. Generator bearings may require lubrication annually. The industry-accepted standard for engine operation and maintenance is $0.015/kWh with a professional maintenance staff. As farms do most of their routine engine maintenance, their costs are a bit lower.

Stirling engines. The Stirling engine is a closed-cycle external-heat engine that uses the same working gas repeatedly without any valve. Modern Stirling engines produce high power and efficiency levels by using high pressure helium or hydrogen as the working gas. However, these engines have not achieved widespread use because of their heavy weight and high production costs.

A popular type of Stirling engine has two pistons that create a 90-degree phase angle and two different areas of the engine that are kept at different temperatures (Figure 5-1). The working gas is perfectly sealed within the engine. Gas expands when heated, and contracts when cooled. Stirling engines move the gas from the hot side of the engine, where it expands, through a regenerator, to the cold side, where it contracts.

The combustion of biogas can be used as an external source of heat for a Stirling engine. The advantage of this configuration is that the biogas does not enter the engine cylinder or come in contact with the working fluid, which results in fewer corrosion problems for the engine. In addition, better emissions controls can be achieved in an external combustion process that is geared toward heat exchange as opposed to power production.

The California Energy Commission conducted the Stirling Engine Generator Biogas Demonstration Project in November 1995. The project was conducted at Sharp Ranch in Tulare, California, by SAIC Corporation. The engine was a Stirling Power Systems V160 engine that used helium as the working fluid. However, the project was beset with a number of operational problems including difficulty operating in parallel with the existing Waukesha internal combustion engine (SAIC, 1995, p. 4-3). The poor performance of this particular demonstration engine is not indicative of the operation of Stirling engines in general, but demonstrates that support by the manufacturer is extremely important for the successful operation of such engines in an on-farm environment. There are currently two Stirling engine manufacturers in the USA: Stirling Thermal Motors of Ann Arbor, Michigan and Stirling Energy Systems of Phoenix, Arizona.

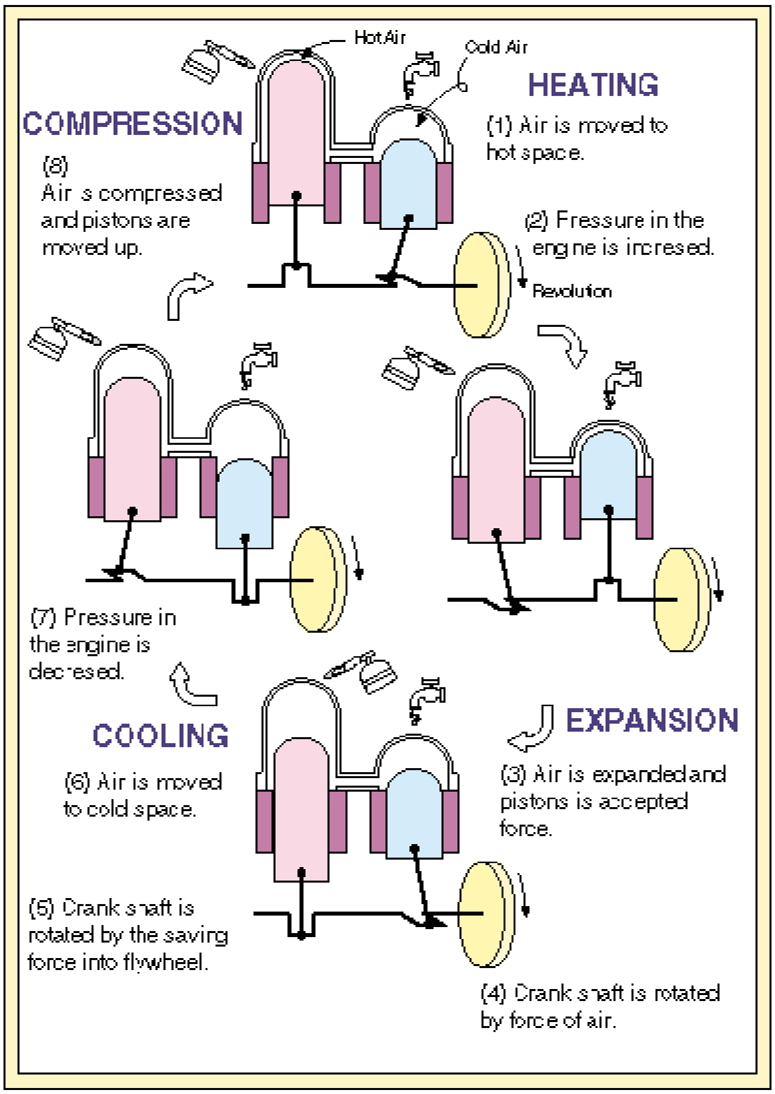

Figure 5-1 Principles of two-piston Stirling engine. (source: <http://www.bekkoame.ne.jp/~khirata/english/still_a.htm, accessed October 22, 2004>)

Recovering heat from biogas engines. For CHP applications, the key to energy savings is recovering heat generated by the engine jacket and exhaust gas. Nearly half of the engine fuel energy can be recovered through this waste heat by, for example, recovering hot water for process heat, preheating boiler feedwater, or space heating. One drawback of gas-driven systems is that the engines are said to require much more maintenance than an electric motor. It is also important to note that irrigation pumping is generally intermittent and refrigeration represents a relatively small component of the biogas use potential of a dairy.

Heat recovery from biogas engines is achieved by jacket-water and exhaust-gas heat-exchange devices. When biogas is produced by plug-flow or complete-mix digesters, the majority of the "waste" heat is used to maintain a digester temperature of around 100° F. When a heat recovery process is used, a balance must be struck between maximizing the amount of heat recovered and maintaining optimal engine operating temperatures. The engine operating temperatures must be high enough to minimize the condensation of carbonic and sulfuric acids in the oil, but low enough to avoid damage to engine components.

Heat recovery from the engine jacket is achieved through a liquid-to-liquid heat exchanger. The maximum temperature that can be supplied to the hot water load is 190° F. Heat recovery from exhaust is carried out through a gas-to-liquid heat exchanger. Exhaust temperatures can reach as high as 1,200° F coming from the engine. The heat recovery system should maintain temperatures no lower than 400° F to prevent acidic vapors from condensing and corroding the exhaust-heat recovery package.

In addition to meeting process heat loads, an engine must have a redundant means of shedding excess heat, whether it is used for CHP or other purposes. This is typically accomplished by an air-cooled radiator that is capable of meeting the engine's maximum cooling requirements. The radiator, which is plumbed in parallel to the heat load, has a fan that is thermostatically controlled and powered by a variable frequency drive in order to modulate heat rejection.

Alternative Uses of Biogas

There are other potential uses of biogas on a farm besides combined heat and power, such as in agricultural pumps, refrigeration, and vehicles. The section below discusses these alternatives and concludes that these uses would be economically challenging and would use only a limited percentage of a dairy's biogas production.

Biogas as a Fuel for Agricultural Pumps

The use of agricultural pumps varies widely from dairy to dairy depending on both on-site conditions and pumping needs. Where agricultural pumps are required (e.g., for irrigation or effluent pumping), dairy farmers have the option of using electric motors, diesel engines, or natural gas engines to drive them. Often the location of the pump and the price of electricity determine this choice. Recent estimates indicate that approximately 82% of the agricultural pumps in California are driven by electrical motors and 18% are driven by diesel engines (the number of agricultural pumps driven by natural gas engines is currently considered negligible) (CEC, 2003a).

Most stationary diesel engines on dairy farms are used for remotely located irrigation pumps (L. Schwankl, UC Davis Agricultural Extension, personal communication, 5 August 2004). Local conditions such as water source (well water vs. irrigation canals), well depth, waste management requirements, acres devoted to feed crops, etc., vary significantly and have a major impact on the pumping requirements. To meet differing requirements, irrigation pump power ratings vary considerably, ranging from about 10 horsepower (hp) to beyond 100 hp (J. Melo, Melo Pumps, personal communication, 30 August 2004).

Converting agricultural pumps to run on biogas. Diesel-driven irrigation pumps can potentially be converted to operate directly on raw biogas, although in practice, the biogas would probably need some amount of cleaning after it is collected from the digester to reduce particulates. The effects of H_2S can be mitigated by an accelerated oil change schedule. The diesel engine modifications required include replacing the fuel injectors with spark plugs, installing a natural gas ignition and carburetor system, installing different pistons to lower the compression ratio, and replacing some of the valve and valve seats. In addition, the diesel gas tank and fuel delivery system would be replaced by low-pressure biogas distribution pipes, valves, and regulators to supply biogas from the on-farm biogas storage tank to the remote irrigation pumps.

Hypothetical demand for biogas as a fuel for irrigation applications. Irrigation pump use is intermittent and highly seasonal and therefore would not consume biogas on a steady basis throughout the year. Also, it would probably be more cost-efficient to switch remote diesel-powered irrigation pumps to electrical power (which could be provided by a generator set using “raw” biogas as fuel) than to upgrade the biogas and transport it via pipeline to feed the remote irrigation pumps.

Despite these barriers to the direct use of biogas for agricultural pumps, we can estimate the hypothetical annual potential demand for irrigation pump fuel use on a 1,000-cow dairy based on the following requirements (J. Melo, Melo Pumps, personal communication, 30 August 2004) and using a conversion factor of 14.7 kWh/gallon of diesel (20 hp-hr/gallon of diesel) (SCAQMD, 2001):

- Number of pumps: 5
- Pump capacity: 40 hp
- Fuel usage per hour: 2 diesel gallon equivalents (DGE)

- Hours operated per year: 1,800 (this assumes an 8-month growing season with 3 months of partial irrigation and 5 months of full-time irrigation)[1]
- Fuel usage per year: 9,000 DGEs

Assuming that a 1,000-cow dairy will produce approximately 50,000 ft^3 of biogas (a cubic foot of biogas contains 600 Btu) there is 30 MM Btu of energy available daily. Since a diesel gallon contains about 140,000 Btu, the biogas from the dairy would be just over 215 DGE/day or about 78,000 DGE/year. Thus, the 9,000 DGEs required to power the average number of irrigation pumps that could be converted to direct use of upgraded biogas corresponds about 12% of the total upgraded biogas output for a 1,000-cow dairy.

Using Biogas to Run Refrigeration Equipment

In general, refrigeration accounts for about 15% to 30% of the energy used on dairy farms (U.S. EPA, 2004). Compressors used for milk chilling are the main sources of energy consumption in the refrigeration system. Since dairy cows are milked daily, a steady source of energy is required for refrigeration needs, unlike seasonal applications such as irrigation pumps.

Hypothetical demand for biogas as a direct fuel for refrigeration systems. Dairies cool milk every day of the year, and compressors for refrigeration run continuously during milking operations, often 20 hours or more each day. For a 1,000-cow dairy farm, the energy requirements for these compressors are typically in the range of 30 to 40 hp (22.5 – 30 kW). However, the implementation of the chilling process (and consequently energy usage) varies greatly according to the local conditions at each farm. In particular, milk prechilling (see below) can result in a significant reduction of the power required for refrigeration compressors.

Virtually all existing refrigeration compressors on dairy farms are driven by electrical motors. While natural-gas driven motors are commercially available for the low-hp ranges associated with dairy refrigeration equipment, they are significantly more expensive than electrical motors with similar output power ranges and therefore have not been traditionally considered as economically desirable choices for this application. Thus, the use of biogas as a direct fuel for refrigeration compressors is not likely.

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[1] A typical irrigation cycle consists of 7 days on and 10 days off. Partial irrigation has an average duty cycle of 30% during the on portion and full irrigation has a 100% duty cycle during the on portion. This equates to approximately 100 hours/month on time during partial irrigation and 300 hours/month on time during full irrigation. Use of irrigation pumps outside the growing season is assumed to be negligible.

If we consider momentarily that such an application were feasible, we could use the following information to estimate the hypothetical annual potential demand for refrigeration compressor fuel use on a 1,000-cow dairy:

- Number of refrigeration compressors: Variable
- Compressor capacity: 40 hp
- Fuel usage per hour: 2 DGEs
- Hours operated per year: 7,300 (assuming an average duty cycle of 20 hours per day during milking cycles)
- Fuel usage per year: 14,600 DGEs

Using a conversion factor of 14.7 kWh/gallon of diesel (20 hp-hr/gallon of diesel) (Southern California Air Quality Management District, 2001), and assuming that a 1,000-cow dairy produces about 78,000 DGE/year, the potential annual fuel demand for on-farm refrigeration corresponds to less than 20% of the total annual biogas output of a 1,000-cow dairy.

Hypothetical demand for biogas as a fuel for prechilling milk. The temperature of dairy milk directly out of the cow is about 98º F; the milk is typically cooled to 38º F for on-farm storage. Although many dairies use well water for prechilling, chilled water or glycol can be produced from biogas-fired absorption or adsorption chillers and used in milk precoolers (these chillers could also be used for air conditioning, but the amount of use on dairy farms would be negligible). Milk cooling using absorption and adsorption chillers also presents a potential opportunity to use waste heat captured from a biogas-driven generator set. Use of this waste heat could significantly reduce the on-farm electrical refrigeration load.

Double-effect chillers, producing hot and cold water simultaneously, are available for applications over 30 tons and could be coupled with a heated digester (1 ton cooling = 12,000 Btu/h). Corrosion-resistant models are not available; therefore, biogas must be treated for water and H_2S removal before it can be used to fuel absorption or adsorption chillers. Absorption chillers can be used to prechill milk, but are typically not capable of providing chilling water below 44º F, which is not sufficient for most dairy needs. Adsorption chillers can generate chilled water temperatures of 37 º F and therefore are marginally capable of handling the entire cooling load without additional refrigeration equipment.

Below is a summary of the capacities, efficiencies, controls, and operating schemes for adsorption chillers that could run on upgraded biogas.

- *Available capacities*: Adsorption chillers are available at various capacities, from 1 ton of cooling per hour and up.
- *Thermal efficiencies*: Adsorption chillers deliver 50% of the biogas Btu as cooling.
- *Control systems*: Adsorption chillers come with commercial control systems.
- *Operating schemes*: Milk cooling requirements do not vary widely over the year. Neither absorption nor adsorption chillers have been widely used in dairy applications, due in part to their relatively higher costs compared to conventional cooling systems (C. Moeller, HIJC USA, personal communication, 3 September 2004).

Most chillers are smaller in capacity than the minimum output covered by air pollution regulations, although larger-scale applications would use California-approved low-NO_x units. Treatment of biogas to remove H_2S would eliminate potential SO_2 emissions.

Biogas as a Vehicular Fuel

There is neither an existing demand nor a projected future demand for raw biogas as a vehicle fuel in California.

The California Air Resources Board (CARB) alternative fuels regulations include specifications for natural gas used as a vehicle fuel (ref. California Code of Regulations, title 13, section 2292.5). While the text of the regulations specifically refers to CNG fuel specifications, it can be argued that biogas should meet the same specifications as CNG for use as a vehicle fuel. The purpose of having minimum CNG fuel specifications is to ensure the compatibility of engines designed to operate on natural gas.

Table 5-1 shows that the typical composition of raw (i.e., unprocessed) biogas does not meet the minimum CNG fuel specifications. In particular, the CO_2 and sulfur (as contained in H_2S) content in raw biogas is far too high for it to be used as vehicle fuel without additional processing. Therefore, according to current regulations, raw biogas is not an acceptable vehicle fuel in the state of California. In addition, no known vehicle engine manufacturers currently offer products rated to operate on raw biogas as a fuel.

Table 5-1 Compressed Natural Gas Fuel Specifications vs. Typical Raw Biogas Composition

Component	CNG Fuel Specification [a]	Raw Biogas Composition [a]
Methane (CH_4)	≥ 88	65
Ethane (C_2H_6)	≤ 6	≤ 0.1
C_{3+} (Propane, etc.)	≤ 3	≤ 0.1
C_{6+} (Hexane, etc.)	≤ 0.2	≤ 0.1
Hydrogen (H_2)	≤ 0.1	≤ 0.1
Carbon monoxide (CO)	≤ 0.1	≤ 0.1
Oxygen (O_2)	≤ 1.0	≤ 0.1
Inert gases (CO_2 + N_2)	1.5 – 4.5 (range)	35
Sulfur	16 ppm	50 – 2000 ppm
Dew point	≥ 10° F below 99% winter design temp [b]	Saturated (non-compliant)
Particulate matter	Non-damaging to engines, etc.	Variable
Odorant	Easily detectable	Detectable

[a] Expressed as % unless otherwise noted.
[b] ASHRAE, 1989 (Chapter 24, Table 1).

Beyond the regulatory impediments to using raw biogas as a vehicle fuel in California, the low methane content of raw biogas (typically 55% to 70%) combined with its inherent trace contaminants (especially H_2S) can have significant negative impacts on engine performance, durability, and emissions. While the degree of impact depends on both engine control and vehicle technology (e.g., open loop vs. closed loop, heavy duty vs. light duty), raw biogas is generally considered technically unsuitable as a vehicle fuel. For these reasons, there are no known vehicle engine manufacturers planning to offer products rated to operate on raw biogas as a fuel.

Summary of On-Farm Demand for Biogas

Table 5-2 summarizes the potential annual demand for raw and upgraded biogas on a typical 1,000-cow dairy. This table includes the most common current on-farm uses for biogas—heat, and electrical power generation as well as the potential alternate uses discussed above.

Table 5-2 Potential Annual Demand for Raw and Cleaned Biogas, Typical 1,000-Cow Dairy Farm

Source/*Use*	**Potential Annual Production**		**Potential Annual Consumption**			
	kWh [a]	**DGE [b]**	**kWh**	**Fuel (DGEs)**	**% of Total kWh**	**% of Total Fuel**
1,000-cow dairy farm	912,000	78,000	---	---		---
Electricity						
Older 1,000-cow dairy farm [c]	---	---	365,000	---	40	
Modern 1,000-cow dairy farm [c]	---	---	803,000	---	88	
Modern 1,000-cow dairy farm with fans [c]	---	---	1,095,000	---	120	
Irrigation pumps	---	---	---	9,000		12
Refrigeration [d]	---	---	---	14,600		19
Total	912,000	78,000	---	23,600		31

kWh = Kilowatt hour

DGE = Diesel gallon equivalent

--- = Not applicable

[a] Assumes that 1,000 cows each produce 50 ft^3 of biogas per day which is 60% methane, and that the biogas is combusted for electrical generation at 28% efficiency.

[b] Assumes that 140 ft^3 of biomethane is equivalent to 1 gallon of diesel, which yields a fuel production capacity of approximately 215 DGEs/day.

[c] Derived from information from energy audits conducted for the California Energy Commission by RCM Digester, which found that older dairies typically use less energy and operate in the 1 kWh per cow per day range, modern dairies operate at 2.2 kWh per cow per day, and modern dairies with fans for cow cooling operate at 3 kWh per cow per day.

[d] In actuality, the likelihood of converting refrigeration units to run on biogas is extremely small (see text discussion, above). However, biogas could be used for prechilling milk. The potential annual consumption for on-farm milk prechilling was not quantified for this study.

As shown in Table 5-2, a modern 1,000-cow dairy would have an annual energy usage ranging from around 800,000 to nearly 1,100,000 kWh per year. This matches well with the potential for electrical power generation of just over 900,000 kWh per year.

Based on the assumptions given, the total potential annual fuel demand for agricultural pumps and refrigeration equipment corresponds to less than a third of the total biogas output for a 1,000-cow dairy. As stated previously, however, irrigation pumps and refrigeration equipment are not necessarily cost-effective applications for biogas. For example, irrigation loads are seasonal. Refrigeration loads are both significant and consistent however electrically-driven refrigeration compressors are less expensive than refrigeration compressors driven by natural gas engines. There may be applications for waste heat to drive adsorption chillers for milk prechilling but the technology is not likely to be cost-effective at the scale of a typical dairy farm.

As shown in Table 5-2, the greatest demand for on-farm use of biogas is for electricity generation. This need matches well with the biogas production capacity and thus, at the present time, we conclude that the most practical use of raw/slightly upgraded biogas is its continued use for on-farm electrical generation.

Potential On-Farm and Off-Farm Uses of Biomethane

Biomethane is equivalent in chemical composition, and therefore in energy content, to natural gas. Equipment that can run on natural gas can run on biomethane; other equipment will have to be converted to accommodate biomethane fuel, as was explained earlier in the discussion about on-farm biogas use. Vehicles are the major category of equipment that can run on biomethane, but not on biogas.

Non-Vehicular Uses of Biomethane

Biomethane is higher quality (i.e., has a greater heating value) fuel than biogas and therefore could be substituted for biogas in all of the applications discussed above as potential or current uses of biogas.

Converting Agricultural Pumps to Run on Biomethane

Natural gas engines will run directly on biomethane. Diesel fueled agricultural pumps that could be converted to run on biogas (see above) would run more efficiently on biomethane using a similar conversion process. Biomethane could be moved around a farm more easily than biogas because it is a cleaner fuel; however, it will likely still be more cost-effective to use biogas to generate electricity to run pumps than to convert the pumps to run on biomethane.

A 1,000-cow dairy that produces 50,000 ft^3 of biogas per year will produce about 30,000 ft^3 of biomethane (assuming that the biogas contains approximately 60% methane), which is equivalent to about 78,000 DGE/year. Assuming the same conditions as described above under the biogas example, biomethane-fueled agricultural pumps would, on average, consume about 12% of a 1,000-cow dairy's biomethane output.

Converting Refrigeration Equipment to Run on Biomethane

The motors in electrically driven refrigeration compressors could be replaced by natural gas engines and fueled by biomethane; however, this is highly unlikely for several reasons. For example, while natural gas engines can be coupled to refrigeration compressors, they are significantly more expensive than their electric counterparts and have much higher maintenance costs. Furthermore, electricity generated from “raw” biogas via a genset is a cheaper fuel than upgraded biogas. In addition, virtually all installed refrigeration compressors today are electrically driven.

Absorption and adsorption chillers driven by waste heat can potentially be used for milk prechilling and cooling on dairy farms but such applications do not appear to be well-suited at present due to higher costs compared to conventional equipment and technical issues relating to process stability. Also, it would be just as easy to operate these prechillers using waste heat from a biogas-fueled genset as it would be to upgrade the biogas and then use it as a fuel.

In summary, there are currently no obvious economic incentives for dairy farmers to either convert electrical refrigeration equipment to operate on biomethane or to replace electrical refrigeration equipment with absorption or adsorption chillers driven by waste heat. For new farms, there may be opportunities to use the waste heat from a biogas-driven genset to drive an absorption or adsorption chiller for milk prechilling, although the overall cost-effectiveness of such a system would be highly dependent on the particular conditions for each farm. Given the current state of technology, using biogas-generated electricity to drive refrigeration compressors may be the most realistic option for using biogas to supply refrigeration loads on dairy farms in the near-term.

Vehicular Uses of Biomethane

Both CNG and LNG vehicles will run on biomethane (i.e., on methane that has been compressed to CBM or liquefied to LBM as described in Chapter 3). Although it is technically feasible to use biomethane as a fuel for alternative-fueled vehicles, there are other important considerations in determining the viability of using biomethane as a vehicular fuel (or a source for other vehicular fuels such as methane). These include current and projected markets for these vehicles, the on-farm demand for vehicle fuel, the potential for on-farm use of alternate fuels, the requirements for converting on-farm vehicles to alternate fuels, and the infrastructure required to support alternative fuel vehicles (AFVs).

California’s Market for Compressed Natural Gas Vehicles

The current and projected CNG vehicle markets in California are summarized in Table 5-3. (See Appendix D for information about specific CNG vehicle models on the market as of late 2004.)

Table 5-3 California Market for Compressed-Natural-Gas-Fueled Vehicles

Vehicle Type	Estimated/Projected Number of CNG Vehicles [a]		
	2004	2007	2010
Light duty [b]	15,500	17,400	19,600
Medium and heavy duty [c]	4,850	7,400 – 8,400	11,200 – 14,500
Total	20,350	24,800 – 25,800	30,800 – 34,100

[a] While exact figures are not available, estimates of the current CNG vehicle market size are based on information provided by the California Natural Gas Vehicle Coalition (CNGVC). These figures have been corroborated with similar estimates in the U.S. Department of Energy Energy Information Administration (DOE EIA) database and supplemented by conversations and reports from various industry sources.

[b] Shuttles, taxis, and municipal fleet vehicles.

[c] Transit buses, school buses, and refuse trucks.

According to the US Department of Energy Energy Information Administration (DOE EIA), the average annual growth rate of the CNG vehicle market in the U.S. has been 12.4% during the last decade and 9.7% during the last three years, with a relatively consistent volume of 8,000 to 12,000 new vehicles per year. (In the western region of the USA, the annual growth rate for the CNG vehicle market was 8.9% in 2002 and 10.8% in 2003.) A breakdown of the statistics for 2001 to 2003 by weight category reveals that the light-duty CNG vehicle market experienced only minor growth (3.9% in 2002 and 4.4% in 2003); however there was significant growth in the combined medium- and heavy-duty markets (20.6% in 2002 and 24.6% in 2003).

Projections for the light-duty CNG vehicle market have been based on recent historical growth rates of approximately 4%. The growth in this market is expected to be fueled primarily by increased demand for CNG shuttles and taxis, which have been successfully demonstrated as ideal applications for this technology, as well as by AFV requirements for government fleets, which are primarily light-duty. Furthermore, many California airports now have regulations and/or incentive programs (for example, SCAQMD Rule 1194, Commercial Airport Ground Access Vehicles) that either require shuttles and taxis serving the airport to use low-emissions AFVs or make it economically attractive for them to do so.

Projections for the medium- and heavy-duty CNG vehicle market are more difficult to make. This is largely because the market tends to be more dependent on the current regulatory environment, which in turn is subject to variability in the political climate (see Chapter 6 for more about the regulatory environment). New, more stringent US EPA heavy-duty truck and bus emissions standards, scheduled to be phased in between 2007 and 2010, may increase demand for medium- and heavy-duty CNG vehicles, as they are expected to result in a price increase for compliant heavy-duty diesel engines and exhaust after-treatment systems. Conversely, the emerging hybrid heavy-duty truck and bus market may have a negative impact on the corresponding segments of the CNG vehicle market.

In general, the growth in this market is expected to be fueled by continued strong demand for CNG transit buses and to a lesser extent, school buses and refuse trucks. There are several regulatory incentives for growth of these market segments:

- CARB Fleet Rule for Transit Agencies
- CARB Clean School Bus Program
- SCAQMD rules for clean transit buses, school buses, refuse trucks, and other public heavy-duty fleet vehicles.

Given the potential variability in the medium- and heavy-duty market, a range of projections has been given based on a conservative annual growth rate of 15% to 20%.

California's Market for Liquefied Natural Gas Vehicles

The current and projected LNG vehicle markets in California are summarized in Table 5-4 below. See Appendix D for information about specific LNG vehicle models on the market as of late 2004.

Table 5-4 California Market for Liquefied-Natural-Gas-Fueled Vehicles

Vehicle Type	Estimated/Projected Number of CNG Vehicles [a]		
	2004	2007	2010
Light duty	Negligible	Negligible	Negligible
Medium duty	0	0	0
Heavy duty [b]	1,200	1,400 – 1,600	1,600 – 2,100
Total	1,200	1,400 – 1,600	1,600 – 2,100

[a] Estimates of the current LNG vehicle market size are based on information obtained from the California Natural Gas Vehicle Coalition, the South Coast Air Quality Management District, INFORM, the DOE EIA database and various additional industry sources.

[b] Transit buses, refuse trucks, Class 8 urban delivery.

According to the DOE EIA, the average annual growth rate of the LNG vehicle market in the U.S. has been 20.1% during the last decade and 8.4% during the last three years; however, volumes have generally been low (typically 100 to 500 vehicles per year) and there has been little consistency from year to year. (In the western region of the USA, the annual growth rate for the LNG vehicle market was 4.1% in 2002 and 12.7% in 2003.) The heavy-duty market accounts for the vast majority of the LNG vehicles in California.

Projections for the heavy-duty LNG vehicle market are subject to the same regulatory and competitive factors as the medium- and heavy-duty CNG vehicle market (see Chapters 6 and 7). In general, the growth in this market is expected to be fueled by continued niche demand for LNG transit buses, refuse trucks, and Class 8 urban delivery trucks (regional heavy delivery). One of the key factors limiting wider acceptance of LNG vehicles is the much lower availability of LNG refueling infrastructure compared to diesel and even to CNG refueling infrastructure. In addition, all of the LNG sold in California is currently imported from LNG production facilities located in other states. Given the current limited emphasis on expanding LNG refueling infrastructure, a range of projections for the heavy-duty market has been given based on a conservative annual growth rate of 5% to 10% assuming that there continues to be a sufficient supply of LNG available in California.

Current and Projected Market for Methanol Vehicles

Methanol (CH_3OH), which is typically manufactured from natural gas feedstock, has been used as an alternative vehicle fuel. The manufacture of methanol from landfill biogas has been demonstrated and manufacturing of methanol from dairy biogas feedstock is theoretically possible (see Chapter 3).

Estimates based on DOE EIA figures show that there are still approximately 3,700 methanol-fueled vehicles in California today, more than 99% of which are light-duty vehicles. In reality, however, virtually all of these vehicles are flexible-fuel vehicles that can operate on either M85 fuel (85% methanol, 15% gasoline) or gasoline. Since there are no longer any M85 refueling facilities operating in California, it is assumed that all methanol-fueled vehicles in the state now use gasoline as their only source of vehicle fuel.

There have been no M85 fuel vehicles offered for sale by vehicle manufacturers since 1998. Naturally this has been a key contributor to the rapid decline in the availability of M85 refueling infrastructure. In addition, other alternative fuel technology such as E85 (85% ethanol, 15% gasoline) has become increasingly well established in this market. As a result, there are no M85 vehicles being planned for future production.

In summary, while there may still be an opportunity to provide methanol to a small number of vehicles in California, there is currently no methanol refueling infrastructure available. The few methanol vehicles on the road are being retired without being replaced. As a result the small potential for methanol as a vehicle fuel in California will disappear.

Summary of Alternative Fuel Vehicles in California

As discussed above, CNG- and LNG-fueled vehicles are the only types of vehicles which are either currently operating or projected to be operating on methane-based vehicle fuels by 2010. This section reviews the present and forecasted markets for CNG- and LNG-fueled vehicles in California, by vehicle type, and provides estimates of the annual fuel consumption represented by these markets.

Current and projected markets. The current and projected natural gas vehicle markets in California are summarized in Table 5-5.

Table 5-5 Summary of California Market for Natural-Gas-Fueled Vehicles

Vehicle Fuel	2004	2007	2010
Raw Biogas [a]	0	0	0
CNG [b]	20,350	24,800 – 25,800	30,800 – 34,100
LNG [c]	1,200	1,400 – 1,600	1,600 – 2,100
Methanol [d]	0	0	0
Total	21,550	26,200 – 27,400	32,400 – 36,200

[a] Biogas does not meet California's vehicle fuel specifications (see Table 5-1).
[b] See Table 5-3.
[c] See Table 5-4.
[d] No M85 refueling infrastructure.

Annual fuel consumption. Certain types of vehicles are normally associated with high annual fuel consumption. Key factors affecting annual fuel consumption include vehicle weight, fuel efficiency, duty cycle, annual hours of operation, and annual mileage. High-fuel-usage vehicles (HFUVs) have an average annual fuel consumption of 5,000 gasoline gallon equivalents (GGEs) or more. By comparison, the remaining vehicles, referred to here as low-fuel-usage vehicles (LFUVs), typically have an average annual fuel consumption of approximately 600 GGEs. School buses, with an average annual fuel consumption of 1,000 to 2,000 GGEs, fall between these two classifications.

The combined annual market for CNG and LNG vehicle fuel in California is approximately 80 million GGEs. Table 5-6 provides estimates of the key contributors to annual CNG and LNG vehicle fuel consumption in California by vehicle type.

Table 5-6 Estimated Annual CNG and LNG Vehicle Consumption in California, 2004

Vehicle Type [a]	Category	No. of Vehicles [b]	Fuel Consumption (GGEs)	
			Vehicle [c]	Total
Compressed Natural Gas Vehicles				
Taxis	Light duty	2,000	6,500	13,000,000
Shuttles	Light & medium duty	2,000	6,500	13,000,000
Transit Buses	Heavy duty	3,600	10,800	39,000,000
School Buses		900	1,500	1,000,000
Refuse Trucks		350	8,600	3,000,000
CNG Subtotal	NA	8,850	NA	69,000,000
Liquefied Natural Gas Vehicles				
Refuse Trucks	Heavy duty	700	8,600	6,000,000
Transit Buses		400	10,800	4,000,000
Class 8 Urban Delivery		100	11,500	1,000,000
LNG Subtotal	NA	1,200	NA	11,000,000
			Total	80,000,000

GGEs = Gasoline gallon equivalents (1 GGE contains 120,000 Btu and uses 120 ft^3 of methane gas)
CNG= Compressed natural gas
LNG = Liquefied natural gas
[a] Vehicle types include school buses and heavy fuel use vehicles with significant representation in the California CNG vehicle market.
[b] Estimated number of vehicles in California.
[c] Typical values

Demand for On-Farm Alternate-Fuel Agricultural Vehicles

Agricultural vehicles include both non-road and on-road vehicles used primarily for farming operations. Examples of non-road agricultural vehicles include tractors, combines, threshers, etc. Examples of on-road agricultural vehicles include pickup trucks and medium- and heavy-duty trucks.

There are currently no commercially available CNG- or LNG-fueled non-road agricultural vehicles. There are, however, commercially available versions of some on-road agricultural vehicles such as pickup trucks. In practice, however, CNG and LNG vehicles are rarely used in on-farm applications due to the lack of convenient refueling infrastructure.

At least one demonstration project has converted several agricultural tractors to CNG fuel and measured the performance of these tractors using CNG versus traditional fuels. The results of this study indicate that CNG tractor conversions are technically feasible and that CNG tractors can meet the expected functional and performance requirements (Davies and Sulatisky, 1989). The economics of farm-tractor conversions to CNG, however, were shown to be very poor due to fuel rebates to farmers, expensive CNG conversion equipment, and the low-annual, high-peak fuel use pattern common for farm tractors (Sulatisky and Gebhardt, 1989). On-farm pickup truck conversions to CNG, performed as part of the same demonstration project, were shown to have much more reasonable payback periods when slow-fill home compressors were used (Sulatisky and Gebhardt, 1989). Another disadvantage noted with respect to CNG-fueled tractors is that tractors are often required to operate for extended periods of time (e.g., 12 hours) during peak seasons such as harvest time; at such times, the need to stop during the workday and return to a central refueling station could be economically undesirable (M.T. Kaminski, Saskatchewan Research Council, personal communication with Brad Rutledge, 5 August 2004).

Liquefied petroleum gas is currently the most widely used type of alternative fuel for agricultural vehicles. Some of the disadvantages of CNG relative to LPG include a lack of CNG refueling infrastructure, higher CNG conversion costs and larger, heavier CNG fuel tanks (National Propane Gas Association website <http://www.npga.org>). As a result, there is little incentive for farmers to choose CNG over LPG.

Table 5-7 shows an estimate of the potential annual fuel demand for a typical 1,000-cow dairy broken down by vehicle type (Nathan DeBoom, Milk Producers Council, personal communication with Brad Rutledge, 30 August 2004). Based on the assumptions provided in the table, total fuel production of a 1,000-cow dairy is about 78,000 DGEs/year. For this case, the potential annual fuel demand corresponds to less than 46% of the total upgraded biogas output for a 1,000 cow dairy. However the lack of factory produced CNG or LNG farm vehicles, the cost of vehicle conversion (discussed below), the cost of storing and pumping the fuel, and the uneven pattern of usage create substantial barriers to the use of CNG (and consequently, CBG) for on-farm vehicles.

Table 5-7 Potential Annual Vehicle Fuel Demand for Typical 1,000-Cow Dairy [a]

Vehicle Type	No. of Vehicles	Hours Operation/Day	Fuel Usage (DGEs)	
			Per Hour	Per Year
Large Tractor	1	4	6	8,760
Med. Tractor	1	5	4	7,300
Small Tractor	1	4	2	2,920
Feeder Truck	1	6	7	15,330
Pickup Trucks [b]	2	2	1	1,460
			Total	35,770

DGE = Diesel gallon equivalent

[a] A 1,000-cow dairy is assumed to produce 30,000 cubic feet (ft^3) of biomethane or 215 DGEs per day (1 DGE = 140 ft^3 methane).

[b] Difference between gasoline gallon equivalents (GGEs) and DGEs ignored for pickup trucks.

As a check on the above estimates, in 2003 the average monthly cost for vehicle fuel and oil expenses on California dairy farms was about $3.00 per cow (CDFA, 2003b). Based on an average non-road price of approximately $1.00/gallon in 2003 (California Farm Bureau Federation, 2004), this implies a fuel usage of around 3 gallons/cow/month. For a 1,000-cow dairy, this translates to an annual vehicle fuel consumption of approximately 36,000 gallons.

Requirements for Converting Agricultural Vehicles to Run on Biomethane

The basic technologies and equipment necessary to convert agricultural vehicles to use upgraded biogas are the same technologies and types of equipment used to convert vehicles to use compressed natural gas (CNG). The main vehicle components and subsystems requiring modification are the engine, fuel storage tanks and fuel delivery system. Conversion of vehicles to use liquefied natural gas (LNG) involves similar modifications to the same vehicle components and subsystems. Note that while retuning natural gas vehicle engines to operate on partially cleaned low-methane biogas may be theoretically possible, such engines are not commercially available and therefore the topic of converting vehicles to use low-methane biogas as fuel has not been investigated further.

Engine modifications are dependent on whether the original engine is diesel- or gasoline-driven. With respect to the types of vehicles normally found on dairy farms, tractors and trucks typically have diesel engines while pickup trucks may have diesel or gasoline engines. Diesel engines employ compression ignition to ignite fuel injected into the cylinders whereas gasoline engines employ spark-ignition. Single-fuel natural gas engines which operate purely on natural gas (the most common type) employ a spark-ignition system. In addition, there is a combination type system called a dual-fuel system where a small amount of diesel fuel is injected into the cylinder with the natural gas and acts as a pilot to ignite the natural gas via compression ignition.

Conversion of diesel engines to run on 100% natural gas (i.e., single-fuel systems) normally requires replacing the fuel injectors with spark plugs, installing a natural gas ignition and carburetor system, installing different pistons to lower the compression ratio, and replacing some of the valve and valve seats. Dual-fuel conversion systems are currently marketed by Clean Air Power in conjunction with Caterpillar diesel engines. This system requires the addition of an electronic control unit to control the relative amount and timing of natural gas vs. diesel fuel injected into a standard, Caterpillar diesel engine. The system also requires a natural gas carburetor and dual-fuel injectors. Dual-fuel conversion systems are normally associated with medium and heavy duty vehicles where performance requirements are more severe. Conversion of gasoline engines to operate on CNG is somewhat simpler since gasoline engines already employ a spark-ignition system. A natural gas mixer to control the ratio of low-pressure natural gas vs. air is the main element of the engine modification.

For single-fuel systems, the diesel tank(s) is replaced by several high pressure CNG storage cylinders. These cylinders hold biogas in compressed form at 3,000 or 3,600 psi in order to provide sufficient fuel to attain a reasonable vehicle range without refueling. The primary drawbacks associated with CNG storage cylinders are their weight, volume and cost. Dual-fuel systems require both a diesel tank and CNG storage cylinders; however, a given vehicle range can be attained with a much smaller diesel tank and somewhat reduced CNG storage requirements compared to a single-fuel system.

LNG has 3.5 times the energy density of CNG and is stored at relatively low pressure (50 to 150 psi). It therefore takes considerably less LNG storage on a vehicle to achieve the same range, resulting in lower weight, volume and cost for LNG storage systems compared to CNG. The primary drawbacks associated with LNG storage cylinders are that the LNG must be stored at very low temperatures (e.g., -260º F) and will evaporate over time due to thermal losses.

For single-fuel systems, the diesel fuel delivery system is replaced by a high pressure gas delivery system including high pressure hoses, a high pressure regulator, a low pressure regulator and miscellaneous monitoring and control devices. In dual-fuel systems, the high pressure gas delivery system is in addition to the existing diesel fuel delivery system. LNG fuel delivery systems are similar to single-fuel gas delivery systems except that the hoses and devices must be insulated for very low temperatures and, in comparison to CNG, will have to handle only relatively low pressures.

Infrastructure for Converting Agricultural Vehicles

Agricultural vehicles on dairy farms usually consist of three basic types of vehicles: tractors, feeder trucks, and pickup trucks. There are currently no companies performing CNG or LNG tractor conversions in the USA. (There is, however, an existing infrastructure to perform LPG tractor conversions, which could provide a framework for the development of a CNG infrastructure.) There are also currently no (original equipment manufacturers) offering new CNG or LNG tractors for sale in the USA.

A feeder truck is usually a class 8 straight truck (a class 8 truck has a gross vehicle weight rating of between 33,000 and 150,000 lbs and a straight truck has a combined body and trailer—i.e., it is not a tractor-trailer combination) upfitted with a feeder box and a mixer. There is no existing infrastructure to convert feeder trucks to CNG or LNG; however, some of the feeder truck chassis manufacturers (e.g., Mack and Peterbilt) offer alternative fuel engine options for their class 8 truck chassis. In addition, there are similar class 8 vehicles (e.g., yard hostlers) that are available from the manufacturer fitted with LNG engines. Thus, it is theoretically possible to procure a CNG or LNG feeder truck through the feeder truck upfitter, although no dairy farmers are known to have ordered such equipment to date.

As of 2005, General Motors (GM) is the only original equipment manufacturer offering CNG-fueled pickup trucks (e.g., the Chevrolet Silverado and the GMC Sierra) in the USA. Ford previously offered CNG- and bi-fueled versions of the F-150 pickup truck, but discontinued production of all CNG vehicles at the end of 2004.

The past decade has shown a marked decrease in the demand for light-duty CNG vehicle conversions and a general trend among CNG component suppliers to align themselves with vehicle original equipment manufacturers. As shown in Table 5-8, a small number of companies in the western USA still convert vehicles to CNG; these companies could help satisfy any demand for CNG conversions of pickup trucks for dairy farms.

Table 5-8 Companies Performing Vehicle Conversions to Compressed Natural Gas Fuel, Western USA

Company	Location	Comments
Baytech Corporation	Los Altos, CA	GM vehicles only
Clean-Tech LLC	Los Angeles, CA	Primarily GM vehicles
DRV Energy, Inc.	Oklahoma City, OK	CNG & dual-fuel conversion kits

LNG pickup trucks are not available from either vehicle original equipment manufacturers or vehicle converters.

Summary of On-Farm Demand for Biomethane

Though the costs of converting all the listed farm equipment to run on biomethane would be very high, Table 5-9 summarizes the potential annual demand for biomethane on a typical 1,000-cow dairy. This table includes heat and electrical power generation as well as uses such as vehicles, agricultural pumps, and refrigeration equipment. As with biogas, however, irrigation pumps and refrigeration equipment are not likely to be cost-effective applications for biomethane. Vehicles cannot run on biogas but they can run on biomethane. However the lack of factory produced CNG or LNG farm vehicles, the cost of vehicle conversion (discussed below), the cost of storing and pumping the fuel, and the uneven pattern of usage create substantial barriers to the use of CNG (and consequently, CBG) for on-farm vehicles.

While the table shows that a typical dairy could theoretically use 76% of the biomethane it produced, the substantial barriers involved make it much more likely that the dairy would seek an external user of the fuel.

Table 5-9 Potential Annual Demand for Biomethane, Typical 1,000-Cow Dairy Farm

Source/*Use*	**Potential Annual Production**		**Potential Annual Consumption**			
	kWh [a]	**DGE [b]**	**kWh**	**Fuel (DGEs)**	**% of Total kWh**	**% of Total Fuel**
1,000-cow dairy farm	912,000	78,000	---	---		---
Electricity						
Older 1,000-cow dairy farm [c]	---	---	365,000	---	44	
Modern 1,000-cow dairy farm c	---	---	803,000	---	88	
Modern 1,000-cow dairy farm with fans [c]	---	---	1,095,000	---	120	
Vehicles [d]				35,770		46
Irrigation pumps	---	---	---	9,000		12
Refrigeration [e]	---	---	---	14,600		19
Total	912,000	78,000	---	59,370		76

kWh = Kilowatt hour
DGE = Diesel gallon equivalent
--- = Not applicable

[a] Assumes that 1,000 cows each produce 50 ft^3 of biogas per day which is 60% methane, and that the biogas is combusted for electrical generation at 28% efficiency.

[b] Assumes that 140 ft^3 of biomethane is equivalent to 1 gallon of diesel, which yields a fuel production capacity of approximately 215 DGEs/day.

[c] Derived from information from energy audits conducted for the California Energy Commission by RCM Digester, which found that older dairies typically use less energy and operate in the 1 kWh per cow per day range, modern dairies operate at 2.2 kWh per cow per day, and modern dairies with fans for cow cooling operate at 3 kWh per cow per day.

[d] The lack of factory produced CNG or LNG farm vehicles, the cost of vehicle conversion, the cost of storing and pumping the fuel, and the uneven pattern of usage create substantial barriers to the use of CBG for on-farm vehicles.

[e] In actuality, the likelihood of converting refrigeration units to run on biogas is extremely small (see text discussion, above). However, biogas could be used for prechilling milk. The potential annual consumption for on-farm milk prechilling was not quantified for this study.

6. Government Policies and Incentives

The successful development of a California biomethane industry will require supportive government policies and financial incentives. New renewable energy technologies are generally more costly than fossil fuels, although some—such as wind energy—have become cost competitive over time. However, renewable energy resources also provide a variety of uncompensated public benefits. For example, the use of biomethane as a replacement for fossil fuels could provide numerous benefits:

- Reduced GHG emissions
- Potential reduction in criteria air pollutant emissions
- Improved water quality through better manure management
- Less dependence on declining fossil fuel supplies
- Better energy security (through a reduced dependence on imported energy)
- Stimulation of rural economies

These are benefits to society rather than financial benefits for the farmer who produces the biomethane. Consequently, it is appropriate for the government to provide support for the development of the biomethane industry.

This chapter discusses various environmental policy drivers, some of which could be used to promote the biomethane industry. It then focuses on specific government policies and incentives in three areas related to the use of biogas and biomethane: renewable energy (electricity), alternative vehicle fuels, and alternative-fuel vehicles and examines programs that could be tapped for financial support. Finally, it discusses why public support of this industry is not only necessary, but justified.

Unfortunately biomethane does not get as much governmental support as other renewable energy sources. Most federal and state policies that support renewable energy and alternative fuels focus either on renewable electricity, often referred to as renewable energy, or on two specific liquid biofuels: ethanol and biodiesel. With a few exceptions, they do not provide specific support for biomethane production. However, vehicles that can run on biomethane fulfill alternative fuel vehicle mandates and earn alternative fuel vehicle incentives.

If the biomethane industry is to prosper, it must help launch policy initiatives that will provide the same direct financial incentives or tax credits that are now earned by programs that focus on renewable electricity, ethanol, and biodiesel.

Policy Responses to Environmental Issues

Environmental policy has a significant effect on the design of dairy manure management systems and biogas production. The release of biogas to the atmosphere contributes to several environmental problems, notably global warming (from methane), ozone (from volatile organic compounds), and unpleasant odors. Ammonia, which is a particulate matter (PM) precursor, may also be released from undigested dairy wastes. Public policy is moving to address emissions from dairy biogas. Public agencies can respond to concerns over dairy gas emissions in the same manner that they respond to other emissions of environmental concern:

- Regulate criteria air pollutants and GHG emissions.
- Control and reduce emissions through market incentives such as a carbon trading market or an emission reduction credit (ERC) market.
- Develop and promote technologies that will help dairies or other sources voluntarily reduce their emissions. This might include subsidies to dairies to help them reduce the creation of biogas or its release into the environment.

Dairies can reduce their biogas production by changing their manure management systems to eliminate flushing and anaerobic storage (aerobically stored manure creates very little biogas). Alternatively, they can capture the naturally occurring biogas or engineer the system to enhance its production and then capture it. Once captured the biogas can be flared, combusted to generate heat or electricity, or upgraded into pipeline-quality gas (biomethane) for use in vehicles or other applications.

Environmental Regulation

Federal and state policies are already in place to help regulate air quality, however, the application of these policies to agricultural activities such as dairy farming has been minimal to date. Control of vehicle emissions has become more stringent in the past decade or more, and has moved in the direction of using biofuels such as ethanol to help control emissions. The existing federal and state regulatory framework for dairy farm emissions is presented below, followed by a discussion of several proposals that are currently pending that could affect dairy emissions (and thus, indirectly, the biogas/biomethane industry). This is followed by a review of regulatory requirements related to vehicle emissions that could impact the alternative fuel industry.

Regulation of Dairy Farm Emissions

The federal Clean Air Act, codified as 42 U.S.C. 7401 *et seq.*, aims to reduce criteria air pollutants (common air pollutants that can injure human health, harm the environment, and cause property damage) (US EPA, 2002). Criteria air pollutants include NO_x, PM, ozone, and other emissions. Neither VOC nor GHGs are defined as criteria air pollutants under the Act; however, VOCs are often included in lists of criteria air pollutants because efforts to control smog focus on reducing VOCs (US EPA, 2002).

Beginning in 1974, California agriculture was exempted from the Clean Air Act under state law. Several years ago, two environmental organizations sued the US EPA to pressure them into ending this exemption. The lawsuit was settled when the US EPA agreed that the exemption should end. As a result of this settlement, Governor Davis signed SB 700 on September 22, 2003. Among other things, this bill requires that dairies that meet size thresholds set by the various local air districts obtain air quality permits. Although there are 35 local air districts in California, most dairies fall within two air districts: the San Joaquin Valley Air Pollution Control District (San Joaquin Air District) and the South Coast Air Quality Management District (South Coast Air District).

Both the San Joaquin and South Coast Districts are developing suitable regulations to comply with SB 700. The San Joaquin District originally proposed that anaerobic digesters be required as a BACT for VOCs (which are also called ROGs in California) for new dairies that have more than 1,954 cows (SJVAPCD, 2004). This draft BACT was withdrawn in settlement of litigation brought against the San Joaquin District by dairy producers. The South Coast District is currently reviewing the technology under its Proposed Rule 1127 (see <http://www.aqmd.gov/rules/reg/reg11/r1127.pdf>).

If these districts require dairies to install anaerobic digesters to control emissions, the commercial production of biogas in anaerobic digesters could receive a needed boost. However, another recent California law, SB 1298, recommends that local air districts require distributed electrical generators to meet central station power plant standards for criteria air emissions by 2007 (CARB, 2002, p. 4). Using current technology, dairy operations that use biogas to generate electricity in internal combustion engines will not be able to meet the 2007 recommended central station power plant standard for NO_x, which is 0.07 lb/MWh or about 1 ppm NO_x.

To deal with this, the South Coast and San Joaquin Districts have proposed a more lenient standard for agricultural engines and waste gas engines. For example, in recently adopted Rule 4702 <http://www.valleyair.org/rules/currntrules/Rule_4702_0605.pdf>, the San Joaquin District established an emission standard of 90 ppm NO_x, for rich-burn spark-ignited agricultural engines such as dairy generators; current dairy digester engines are to be retrofitted by 2008. Waste gas engines are limited to 50 ppm NO_x. Although these standards are much more lenient than the central station standard, even this level of emissions will be costly to meet.

Technical solutions that will enable dairies with anaerobic digesters to meet the 90 ppm NO_x standard likely exist, though none has yet been demonstrated to run successfully over time at an actual dairy digester site. If air districts adopt the SB 1298 recommendations, dairies may find themselves forced to collect biogas but unable to combust it to produce electricity, as combustion would produce NO_x in excess of the new standard. In this situation, it may be more advantageous for dairies to collect the biogas and flare it using a low NO_x flare or upgrade it to biomethane and use it as a substitute for natural gas. Flaring produces less NO_x than combustion in an IC engine because it occurs at a lower temperature, but it may still produce more than the 5 ppm NO_x recommended in the CARB 2007 standard. Biomethane could also be combusted in a microturbine to generate electricity.

Currently there is no regulation of GHG emissions that would affect a dairy anaerobic digester. If such regulation came into force, however, it could provide an additional incentive for the commercial production of dairy biogas or biomethane as an energy source. Greenhouse gas regulations could force dairies to collect and combust their methane emissions. If those costs were already required, the additional cost to generate electricity or create biomethane might be low enough to make energy production worthwhile.

Regulation of Vehicle Fuel Emissions

The Clean Air Act Amendments of 1990 requires gasoline in areas with unhealthy levels of air pollution to contain fuel oxygenates, cleaner burning additives that reduce carbon monoxide emissions. Both ethanol and MTBE are acceptable oxygenates. The oxygenated fuels program began in 1992 and required oxygenates during cold months (winter) in cities that had high levels of carbon monoxide (a criteria pollutant). Most cities that needed to address carbon monoxide in winter used ethanol. In 1995, cities with the worst ozone problems were required to add oxygenates; most chose MTBE. California adopted more stringent gasoline requirements.

Soon, MTBE emerged as a water quality problem. The phase-out of MTBE began in California in 1999 and was pursued by the federal government in 2000. Ethanol has replaced it. While CARB contends that California’s reformulated gasoline (RFG3) provides all the air quality benefits of oxygenated gasoline, the US EPA still requires oxygenation of California gasoline in non-attainment regions such as the Central Valley and the South Coast: gasoline in these regions is required to contain at least 2% oxygen by weight. California completed its phase-out of MTBE in 2003 and is now adding ethanol to fuel to meet the oxygenation requirement. Typically, an ethanol content of about 6% is needed (CEC, 2003b, p. 27-28). About 80% of California’s gasoline now contains ethanol.

Market-Based Incentives for Emission Control

The regulatory approach, often called the “command-and-control approach,” to pollution reduction has been criticized in recent years for various reasons. According to Robert Crandall of the Brooking Institution (2002), one problem is that regulatory agencies may not always get it right—they may decide to control the wrong substances or control some discharges too strictly and others not enough. Also, pollution regulation can make the cost of goods more expensive and, because controls are typically stricter for new sources than for older existing ones, can discourage the building of new, more efficient facilities. Finally, regulations can be difficult to enforce and do not encourage compliance beyond what is mandated. As a result of these problems, policymakers have begun to include market-based incentives as a means to reduce pollution (Crandall, 2002).

There are two basic types of market incentives: pollution fees and emissions trading. Pollution fees, commonly used in Europe but not in the USA, are taxes that penalize polluters in proportion to the amount they pollute. Emissions permits, allowed by the 1990 Clean Air Act, enable polluters to trade "permits to pollute" so that they can meet the overall control levels set by regulatory authorities. Two types of emission trading permits could impact the biogas/biomethane industry in the USA: carbon trading and ERCs.

Regulatory initiatives affect both carbon trading and emission reduction markets. If ERCs are required under SB 1298 and by local air district regulations, as described above, those reduced emissions would not be tradable on the carbon or emission reduction credit markets.

Carbon Trading

As of early April 2005, the proposed Kyoto Treaty was ratified, accepted, or acceded by 148 nations; the USA is one of six signatory nations that have not ratified the treaty (<http://unfccc.int/files/essential_background/kyoto_protocol/application/pdf/kpstats.pdf>). The Kyoto Treaty requires signatory countries that ratify the treaty to reduce GHG emissions. In response to the treaty, a market for reduced carbon emissions, commonly called the Carbon Market, has emerged. Under this cap and trade system, firms that are required to reduce their GHG emissions can either control their own emissions or buy reductions from other firms that have been able to reduce emissions at a lower cost.

If the USA were to ratify the Kyoto Treaty, dairy digesters within the country would be well-suited to trade carbon credits. As explained in Chapter 2, the collection and combustion of pre-existing methane destroys the methane while producing a similar amount of carbon dioxide as by-product. Since methane has 21 times the global warming potential, by weight, of carbon dioxide, dairies that combust methane which would otherwise be released into the atmosphere would gain a substantial number of carbon credits.

Because the Carbon Market is undeveloped in the United States, each trade is largely a pioneering effort, and transaction costs are very high. At present, even if a dairy could arrange a carbon trade, it could not begin to recover the transaction costs involved. However, if the USA signs the Kyoto Treaty, or if the Carbon Market develops for other reasons, dairies might be provided with an incentive to collect and use more biogas.

Emission Reduction Markets

California has a market in place for ERCs. New sources of criteria air emissions are required to mitigate emissions by purchasing ERCs from other pollution sources that have already managed to reduce emissions. As currently structured, this market does not allow agricultural enterprises to participate effectively; however, if such participation were possible, dairies might be provided with an incentive to collect biogas, thus reducing VOC emissions and gaining ERCs. However, the problem of NO_x emissions from biogas combustion might prove to be an expense on the ERC market. Depending on the relative volume and prices of these two pollutants (VOC vs. NO_x) a dairy might show net credits or debits on the ERC market. This, in turn, would affect the dairy's interest in pursuing biogas production for electricity or biogas production for non-electrical energy.

Promotion of Environmentally Beneficial Technologies

In addition to regulation and the promotion of market-based incentives, governments can encourage the development and use of new technologies that provide environmental benefits while meeting demand. There are several approaches that can help encourage new technologies: tax credits or incentives, subsidies through direct funds, and long-term contracts that guarantee market and/or price. For example, in response to concerns about the contribution of methane to climate change, the US EPA set up the AgSTAR program (see <http://www.epa.gov/agstar/>) to develop and disseminate information about anaerobic digesters for animal waste. AgSTAR funds research and has sponsored at least one national conference. The California Energy Commission (CEC) has also funded research, through its Public Interest Energy Research (PIER) program on anaerobic digestion for electrical production. The CEC views anaerobic digesters on dairies as a potential source of relatively clean renewable energy. The continued expansion and success of these federal and state efforts will promote the production of commercial dairy biogas.

Government Policies and Incentives for Renewable Energy

The interest in renewable energy in the USA dates from the Arab oil embargo of 1973 and the oil price shock of 1979 that was triggered by the fall of the Shah of Iran. By the late 1970s energy conservation, renewable electricity and alternative fuels were focal points for public policy. The Public Utility Regulatory Policy Act (PURPA) of 1978 began Federal support for renewable electricity and distributed electrical generation. In the same year, the Energy Tax Act initiated support for alternative vehicle fuels (see discussion later in this chapter).

Much federal policy and most renewable energy policy at the state level is directed toward the development of renewable electricity generation from wind, solar, geothermal, and small hydropower sources, as well as from biomass. The following discussion focuses on support for the latter, as it is most pertinent to biogas and biomethane production.

Federal Support for Biomass Energy Sources

Federal support for the production of energy (primarily electricity) from biomass comes primarily from two pieces of legislation: the Biomass Research and Development Act (BRDA) of 2000 and the Farm Security and Rural Investment Act (Farm Bill) of 2002.

Biomass Research and Development Act

The Biomass Research and Development Act of 2000 (BRDA) (Public Law 106-224, as amended through Public Law 108-199 of 2004) committed the federal government to the development of biobased industrial products including fuel, electricity, and heat from biomass. In addition, it established a Biomass Research and Development Board, a Technical Advisory Committee, and a Biomass Research and Development Initiative.

In 2002, the Technical Advisory Committee published a “vision” that calls for biobased transportation fuels. Currently, biobased fuels make up 0.5% of U.S. transportation fuel consumption; BRDA requires this to increase to 4% in 2010, 10% in 2020, and 20% in 2030 (BTAC, 2002, p. 9). Although this vision calls for biobased transportation fuels to increase much more dramatically than biopower (electricity and heat), the accompanying “roadmap” references anaerobic digestion as a source of biopower (electricity and heat). The roadmap does not mention anaerobic digestion as a source of transportation fuel, which it could be if the produced biogas were upgraded to biomethane.

Section 307 of BRDA launched a Biomass Research and Development Initiative. The research is aimed at understanding the conversion of biomass into biobased industrial products such as fuel and electricity, developing new cost-effective technologies to promote commercial production, ensuring that economic viability and environmental benefits of biobased products, and promoting the development and use of agricultural energy crops. Eligible grantees include universities, national laboratories, federal or state research agencies, and private or nonprofit organizations. Grants are awarded competitively. The Farm Bill of 2002 (Title IX, Section 9010), discussed below, appropriated funds for the program and extended its term from 2005 to 2007.

Farm Security and Rural Investment Act Of 2002

The Farm Security and Rural Investment Act of 2002 (Farm Bill) contains a variety of loan and grant programs that support the development of a renewable methane industry from dairy biogas (see USDA Farm Bill website at <http://www.usda.gov/farmbill/>). These programs are discussed in three sections of the bill: Title II, Conservation; Title VI, Rural Development; and Title IX, Energy. Some of the most promising sections in Title IX are either unfunded or have been defined in such a way as to exclude renewable methane.

Programs Authorized Under Farm Bill Title II, Conservation. The following programs have been authorized under Title II of the Farm Bill.

Environmental Quality Incentives Program. The Farm Act of 1996 established the Environmental Quality Incentives Program (EQIP) and Title II, Subtitle D of the 2002 Farm Bill extends this program. The objective of EQIP is to encourage farmers and ranchers to adopt on-farm environmental conservation improvements through the use of five- to ten-year contracts. Eligible improvements include those related to improved soil, water, and air quality, and the program provides education, technical assistance, cost-share payments, and incentive payments. Because anaerobic digesters that produce biogas (and lead to its subsequent capture and combustion or flaring) provide air and water quality improvements, they are eligible for this program, and have been funded.

Contracts signed under EQIP must be effective for no less than one and no more than ten years. Applications are accepted on a continuous basis. Generally, EQIP payments are limited to 75% of the cost of a project, though in some cases they may cover up to 90%. Payments for an individual farm are limited to a total of $450,000 in the fiscal year (FY) 2002-to-2007 period. Sixty percent of the funds under the EQIP program target livestock production; there is no cap per animal unit. Livestock operations are required to develop a comprehensive nutrient management plan.

The program is funded through the Commodity Credit Corporation and is mandated at $1.0 billion in FY 2004, $1.2 billion each in FY 2005 and 2006, and $1.3 billion in FY 2007. Since EQIP began in 1997, the USDA has entered into over 100,000 contracts with farmers, covering more than 50 million acres.

Conservation Innovation Grants. The Conservation Innovation Grants program (Section 1240H) provides support to government and nonprofit activities that aim to stimulate innovative approaches to environmental enhancement. Funds can be used to carry out projects that involve EQIP-eligible farmers, but CIG funds are limited to 50% of the total cost of the project. In FY 2003, $15 million was made available under this program (USDA, 2004b).

Programs Authorized Under Farm Bill Title VI, Rural Development. Section 6013 expanded eligible loan programs under Title VI to specifically include anaerobic digesters as a renewable energy source. No specific funds were earmarked for this technology.

Section 6401 provides funds that can be used for planning grants or for working capital through Value Added Agricultural Product Market Development Grants. The language in this section specifically includes farm- or ranch-based renewable energy as an eligible product. In FY 2003, $28 million in grants were awarded under this section (USDA, 2004b). In FY 2004, $13 million has been appropriated. This report was funded by a VAPG grant.

Programs Authorized Under Farm Bill Title IX, Energy. A number of programs related to biobased energy production are funded under this title, but few include biomethane as a fuel source. Nevertheless, some of the programs discussed below could be expanded to include funding for biogas/biomethane production.

Federal Procurement of Biobased Products. Section 9002 of Title IX provides for a federal procurement preference for biobased products; a proposed rule for this program was published in December 2003 (Federal Register Vol. 68, No. 244, December 19, 2003, page 70730). The proposed rule is geared to support new markets for biobased products—both the legislation and the proposed rule exclude motor vehicle fuels and electricity. There is, however, a category for fuel additives that could be used for vehicles, heating (of buildings), and other similar uses. This category includes both liquid biobased fuels, specifically ethanol and biodiesel, and solid fuels (Federal Register Vol. 68, No. 244, December 19, 2003, page 70738). During a public meeting about the proposed rule held on January 29, 2004, a USDA spokesperson stated that alternative fuels such as ethanol (E100), ethanol 85% (E85), biodiesel (B100) and biodiesel 20% (B20) are ineligible for funding through this program, but mentioned that fuel additives such as ethanol 10% (E10) or biodiesel 2% (B2) are eligible. The spokesperson did not characterize the intermediate cases (USDA, 2004a, p. 41).

Even though compressed biomethane is gaseous and the proposed rules do not mention gaseous fuels, it is unlikely that biomethane, when added to CNG, would be considered a "fuel additive."

Biorefinery Development Grants. Section 9003 of Title IX assists in the development of new and emerging biomass technologies, and specifically includes transportation fuels. A biorefinery is defined as a process that converts biomass into fuels and chemicals. The Biorefinery Development Grants pay for the development and construction of biorefineries that demonstrate commercial feasibility of a process. Grants cannot exceed 30% of the cost of the project. No federal funds have been appropriated for this section.

Biodiesel Fuel Education Program. Nearly $1 million in grants were issued in 2003 for the Section 9004 biodiesel fuel education program; this program, however, is not relevant to biomethane.

Energy Audit and Renewable Energy Development Program. Section 9005 of Title IX authorizes a competitive grant program for entities to administer energy audits and renewable energy development assessments for farmers, ranchers, and rural small businesses. No federal funds have been appropriated for this section.

Renewable Energy Systems and Energy Efficiency Improvements. A loan, loan guarantee, and grant program to assist eligible farmers, ranchers, and rural small businesses in purchasing renewable energy systems and making energy efficiency improvements is authorized under Section 9006 of Title IX. In FY 2003, $22 million in grants was awarded under this program, and $23 million is appropriated for FY 2004 grants. Grants alone cannot exceed 25% of the cost of the project and grants and loans made or guaranteed are not to exceed 50% of the cost. Renewable energy grants are limited to $500,000. Financial need must be demonstrated.

Hydrogen and Fuel Cell Technologies. Section 9007 of Title IX instructed the USDA and the US DOE to develop a memorandum of understanding on cooperation among rural communities and agricultural interests relative to hydrogen and fuel cells. Biomethane is a potential feedstock for fuel cell hydrogen (see Chapter 3).

Biomass Research and Development. Section 9008 of Title IX extends the termination date of BRDA to September 30, 2007 and funds the BRDA Section 307 research and development initiative with $75 million for the period FY 2002 to 2007. In FY 2003, $16 million of USDA funds under this provision were combined with $5 million from US DOE to fund a joint solicitation; actual awards totaled $22 million. In FY 2004, $25 million was awarded to 22 projects, with $13 million contributed by USDA and $12 million from the US DOE. Recipients of funds must share 20% of the costs under this program.

Cooperative Research and Development. Although Title IX, Section 9009 provides discretionary authority for competitive grants to research carbon fluxes and GHG issues, it is not relevant to biomethane.

Continuation of Bioenergy Program. Section 9010 of Title IX provides producer payments for increased production of bioenergy. This provision was funded in the legislation at $150 million annually from FY 2002 to FY 2006; nearly $150 million was awarded in 2003. However, as stated in this section of the Farm Bill, "'bioenergy' means biodiesel and fuel grade ethanol." Thus, producers of biomethane are not eligible for payments under this program.

Energy Policy Act Of 2005

Many provisions of the Energy Policy Act of 2005 support biomass energy. At the time of final editing, the bill has just been signed; an analysis of its provisions will not be undertaken in this study. The energy bill should be carefully reviewed to determine its possible impact on biogas and biomethane production.

California Renewable Energy Programs

California has a major commitment to renewable energy, including renewable electricity from biomass. The Public Interest Energy Research (PIER) program, which focuses on electricity, has been funded by ratepayers for nearly ten years. The new California Natural Gas Research and Development Program, described below, provides funds for research and development of natural gas, including renewable natural gas. A number of state programs specifically target renewable energy (primarily electricity); these include the Renewable Portfolio Standard, the Self Generation Incentive Program, and the New Renewables Program. If biogas production is used to generate electricity it could qualify for several of these programs, as discussed below. When biogas or biomethane is used as a gaseous fuel for transportation, heat, or similar uses, however, it is ineligible for these funds.

Natural Gas Research and Development Program

In 2000, California's Governor signed Assembly Bill (AB) 1002, which created a surcharge on natural gas consumption to fund public-purpose activities. These activities included public interest research and development as authorized by California Public Utility Code Section 740, which describes electrical and gas research and development and specifically lists “environmental improvement” and “development of new resources and processes, particularly renewable resources” as project objectives. AB 1002 did not propose a specific funding amount.

On August 19, 2004 the California Public Utility Commission (CPUC) released Decision 04-08-010, which established the CEC as the administrator of the research and development program and allowed the CEC to make funding decisions. The funding cap was $12 million annually, starting on January 1, 2005; this will increase by $3 million each year through 2009. The maximum cap approved is $24 million, at which time the CPUC will reexamine the funding cap (CPUC, Rulemaking 02-10-001, Decision D0408010, p. 38. See <http://www.cpuc.ca.gov /word_pdf/FINAL_DECISION/39314.pdf>). Prior to this decision, research was administered by the investor-owned utilities at a statewide level of $4.5 million per year.

Natural gas generally refers to a fossil fuel, but biogas is also a gas, and is also natural. For example, Pacific Gas and Electric’s Gas Rule 1, a document approved by the CPUC, specifically defines natural gas to include “gas obtained from biomass or landfill” (Pacific Gas and Electric, Gas Rule 1 Definitions).

The CEC has submitted a report to the CPUC that outlines a research plan to be funded through this program, which will be called the Public Interest Natural Gas Energy Research Program (PING); the report specifically mentions “renewable natural gas” as one component of the plan The inclusion of this language was the result of information submitted by one of the authors of this report. In the same way, supporters of biomethane should work to expand programs intended to promote or research natural gas or alternative vehicles fuels to include biomethane.

Financial Incentives for Anaerobic Digesters

The development of new energy resources, particularly renewable energy resources, typically is supported by federal and state grant programs or tax policies because the environmental benefits from these technologies serve the public good. Anaerobic digesters for electrical generation have received both federal and state subsidies, but these funds are usually not available if the biogas is not used to generate electricity. For example, a program authorized under California’s SB 5X provided $15 million to support the building of manure digesters for electrical generation, of which $10 million was directed to on-farm dairy digesters. The program covered up to 50% of the capital costs of the dairy digester, but is now closed to new applicants.

Financial Incentives for Renewable Electricity

The Self Generation Incentive Program, authorized by California AB 970, provides incentives to customers who generate their own clean grid-connected electricity. The program has recently changed. Electrical generators that run on renewable fuel such as biogas can earn a capital grant of $1.00/watt of installed capacity with no limit as to what proportion of the engine cost is covered. These funds will cover the engine-generator and related items, but not the anaerobic digester itself.

The Renewable Resources Trust Fund provides more than $1 billion per year for the Existing Renewable Program, the New Renewables Program, and the Emerging Renewables Program. The Existing Renewables and the New Renewables Programs provide incentive payments per kWh for renewable generation, including biomass and biogas. The Emerging Renewables Program does not fund biomass to electricity unless the produced biogas is used in a fuel cell.

California is committed to increasing its use of renewable electricity generation. The Renewable Portfolio Standard, established by SB 1078, mandates the three California investor-owned utilities to increase their use of renewable energy to 20% by 2017 (see <http://info.sen.ca.gov/pub/01-02/bill/sen/sb_1051-1100/sb_1078_bill_20020912_chaptered.pdf>). The Sacramento Municipal Utility District has made a similar commitment, and Los Angeles Department of Water and Power may do the same.

Net Metering For Solar, Wind, and Dairy Biogas Sources of Electricity

Net metering is available for wind and solar electrical generation under AB 58, which allows a self-generator to credit electricity exports against imports. Thus, solar or wind self-generators can eliminate their electrical bills. Dairy biogas has net metering for self-generated electricity under AB 2228, but credits can be applied only to the generation charge, which is only one component of the electricity bill. Net metering for dairies will sunset in January 2006, if proposed new legislation (AB 728) is not approved.

Renewable Electricity Research and Development

California’s electricity ratepayers provide $62 million per year to fund the Public Interest Energy Research (PIER) program, which is administered by the CEC. The PIER program focuses on electricity. Two of the six PIER research and development areas are renewable electricity and the environmental effects of electrical generation. The PIER renewable energy program has funded research on anaerobic digester technology for electricity generation as well as other biomass-to-electricity technologies.

Government Policies and Incentives for Alternative Fuels

Many government policies and incentives that promote the use of natural gas fuels such as CNG and LNG will also serve to promote the adoption and use of biomethane as a vehicle fuel. A number of programs, both at the state and federal levels, are currently in place for this purpose.

Still, the incentives for biomethane use in vehicles are weak overall. A number of California provisions that provided financial incentives for natural gas vehicle usage have recently expired and show no signs of being revived. Other incentives and programs focus on small portions of the automotive market and/or do not contain significant amounts of funding.

Federal Policies and Incentives for Alternative Fuels

Today, much of the focus of federal renewable energy policies and incentives is on two liquid biomass transportation fuels that have large farm state constituencies: ethanol and biodiesel. For example, the Bioenergy Program outlined in the 2002 Farm Bill (Section 9010) provides $150 million annually to producers of “bioenergy,” which is defined as ethanol and biodiesel. Biomethane is not included in the definition of bioenergy.

Ethanol is predominantly derived from corn, and biodiesel predominantly from soybeans. Both are major crops in the Midwest and have received substantial political support from farm state senators from both parties. There has been a 25-year history of federal support to the ethanol industry, while support for biodiesel is more recent.

Federal support for ethanol dates from 1978 when the Energy Tax Act (P.L. 95-618) provided an exemption to the federal fuel excise tax on gasoline for fuel blended with at least 10 percent ethanol (E10). In 1980, domestic fuel development was promoted in the Energy Security Act of 1980 (P.L. 96-294). The Surface Transportation Assistance Act of 1982 (P.L. 97-424) raised the federal excise tax to $0.09/gallon and also raised the ethanol exemption to $0.05/gallon for gasoline fuel that contains E10. The ethanol exemption was raised to $0.06/gallon in 1984, but then lowered to $0.054 in 1990 and extended to 2000 (CEC, 2004, p. 6). The Transportation Equity Act for the Twenty First Century of 1998 (TEA-21) (P.L. 105-78) extended the ethanol exemption to 2007, and lowered it to $0.053 in calendar years 2001 and 2002, to $0.052 in calendar years 2003 and 2004, and to $0.051 in calendar years 2005, 2006, and 2007 (Surface Transportation Revenue Act of 1998, Section 9003). Since the incentive is for a gallon of fuel that is 10% ethanol, the current exemption ($0.051) is effectively $0.51 per gallon of ethanol used. In addition, an exemption of $0.04 is allowed for fuel that contains 7.7% ethanol, and $0.0296 for fuel that contains 5.7% ethanol (CFDC, 2003, p. 24).

The Omnibus Reconciliation Tax Act of 1980 (P.L. 96-499) placed a tariff on imported ethanol; the tariff is currently $0.54/gallon. The Omnibus Budget Reconciliation Act of 1990 (P.L. 101-508) enacted a small ethanol producer tax credit of $0.10/gallon

As summed up by the CEC, “The federal ethanol fuel incentives...are generally acknowledged as the driving force for ethanol production and use in the U.S…..This incentive (or subsidy) has made ethanol competitive with gasoline….Without this long-standing federal energy policy it is highly unlikely that ethanol production and use in the U.S. would have reached its current level….And the tariff on most imported ethanol protects domestic producers against a large share of the U.S. ethanol fuel market being captured by lower-cost foreign producers” (CEC, 2004, p.7). Since 1979, U.S. ethanol production has grown from 10 million to 3,000 million gallons per year.

Table 6-1 summarizes existing federal government policies and incentives that could help spur the use of biomethane use in vehicles and shows their relative ranking in this regard. In addition to the policies established by the Farm Bill, there are two major programs, discussed below.

Table 6-1 Federal Policies and Programs that Encourage Alternative Fuels, Ranked According to Presumed Impact on Growth of Biomethane Industry

Policy/Program	Value for Biomethane Industry	Explanation
Energy Policy Act of 2005 (proposed)	High Potential Value	Includes incentives for renewable vehicular fuels including a requirement to increase the use of renewable fuels, including those produced from biomass, in the U.S. motor fuel supply and another that promotes renewable electricity generated from bovine and swine waste.
2002 Farm Bill: Biorefinery Development Grants	High Potential Value	Grants specifically targeting the development of new and emerging biomass transportation fuels.
State Energy Program (SEP)	Medium	Provides direct funding for renewable energy, including biogas, but funding level is low.
Pollution Prevention Grants Program	Low	Supports innovative pollution prevention programs. Wide range of technologies and fuels qualify. No specific incentive for renewable methane.

High = Provides substantial incentives for both natural gas vehicle use and biomethane production.
Medium = Provides adequate incentives for natural gas vehicle use or biomethane production, but not for both.
Low = Provides inadequate incentives for natural gas vehicle use or biomethane production.

State Energy Program

The State Energy Program (SEP) provides US DOE funding for renewable energy and energy-efficient technologies. About $5,000,000 is available for alternative fuels: nearly $300,000 for bioenergy and biobased projects and fuels, and over $525,000 for biomass power.

Pollution Prevention Grants Program

This federal program supports the establishment and expansion of state pollution prevention programs and addresses various topics of concern such as energy, transportation, industrial toxins, and agriculture. Funds available under this grant/cooperative agreement are awarded to support innovative pollution prevention programs that address the transfer of potentially harmful pollutants across all media: air, land, and water. State agencies are required to contribute at least 50% of the total cost of their projects.

California Alternative Fuel Programs

In the early 1980s, California created incentives for ethanol fuel including a state excise tax reduction of $0.03/gallon for 10% ethanol blends (the excise tax was $0.07/gallon). This incentive was in place from 1981 to 1984. In 1988, SB 2637 established a $0.40/gallon incentive for liquid fuels fermented in state from biomass, but this initiative was never funded (California Public Resources Code, Section 25678). In contrast to 22 other states that have ethanol incentive programs, California does not currently have tax incentives in place for ethanol (CEC, 2004, p. 3-4), nor does it have any financial incentives or tax credits for the use of biodiesel, unlike a number of other states (US DOE, 2004).

Table 6-2 ranks California policies and programs that provide incentives for using alternative fuels. Details of the various programs are discussed below.

Excise Tax Options

The excise tax imposed upon CNG, LNG, and LPG as vehicle fuels can be paid through an annual flat-fee rate sticker tax based on vehicle weight. Conversely, owners and operators may pay excise tax on CNG of $0.07 per 100 ft^3, on LNG of $0.06 per LNG gallon (California Revenue and Taxation Code Section 8651.6), and on LPG of $0.06 per LPG gallon (California Revenue and Taxation Code Section 8651.5). Excise taxes on ethanol and methanol containing not more than 15% gasoline or diesel fuel are $0.09 per gallon (California Revenue and Taxation Code Section 8651, and Section 8651.8).

California Natural Gas Research and Development Program

As discussed earlier in this chapter, on August 19, 2004 the CPUC released Decision 04-08-010, its final rule under Rulemaking 02-10-001 implementing AB 1002. This bill uses a surcharge to significantly increase natural gas research and development, including “development of new resources and processes, particularly renewable resources,” in California. Beginning on January 1, 2005, the program funding increased from $4.5 million to $12 million; by the fourth year, funding will be ramped up to $24 million.

Table 6-2 California Policies and Programs that Encourage Alternative Fuels, Ranked According to Presumed Impact on Growth of Biomethane Industry

Policy/Program	Value for Biomethane Industry	Explanation
Excise Tax Options	Low	Flexibility for payment (flat fee or per quantity of fuel) of natural gas excise tax. Very low natural gas vehicle incentive. No specific incentive for renewable methane.
California Natural Gas Research and Development Program	Medium	Significantly increases funding for natural gas R&D. Renewable sources are mentioned, but are not allocated a specified portion of the funding.
Public Transit Bus Rule	Medium	Fleets can choose alternative fuels or clean diesel technologies to satisfy these requirements. No specific incentive for biomethane.
California Assembly Bill 2076	Medium Potential Value	Focus on GTL, natural gas, and increasing alternative fuel use could marginally stimulate biomethane industry.
State Fleet Energy Consumption Reduction Goal	Low	Natural gas vehicles can qualify towards the goal of reduced energy consumption, but so can efficient and low-polluting gasoline vehicles. No specific incentive for biomethane.

GHG = Greenhouse gases.
GTL = Gas-to-liquid, such as the Fischer Tropsch process.
High = Provides substantial incentives for both natural gas vehicle use and biomethane production.
Medium = Provides adequate incentives for natural gas vehicle use or biomethane production, but not for both.
Low = Provides inadequate incentives for natural gas vehicle use or biomethane production.

New Emission Standards for Public Transit Buses

A public transit bus rule adopted by CARB in February 2000 regulates public transit fleets and sets emission reduction standards for new urban transit buses (California Code of Regulations [CCR], Section 1956.1, Title 13). The rule allows transit fleets to choose one of two options in order to reduce their emissions to the required levels: using low-sulfur diesel or using alternative fuels, such as natural gas. As enforcement of the 2007 and 2010 urban bus emission standards approaches, diesel systems become more complicated, and thus more expensive. Consequently, the cost differential between alternative fuel natural gas systems and diesel systems will decrease and alternative fuel may become an increasingly attractive option. To date, however, approximately two-thirds of California transit agencies have chosen to use low-sulfur diesel to meet the required emission levels.

Reduced Automotive Greenhouse Gas Emissions

Assembly Bill 1493, which was passed in 2002, was the first piece of legislation in the world to mandate reductions in automotive GHG emissions. The bill focuses exclusively on the vehicle side of the equation (i.e., tailpipe emissions of GHG). The bill required the CARB to study the cost effectiveness of various technologies to reduce GHG emissions from autos, including the use of alternative fuels. While natural gas is a lower GHG-emitting fuel the CARB concluded that changes in gasoline engine technologies were more cost effective than alternative use vehicles (see <http://www.arb.ca.gov/cc/042004workshop/final-draft-4-17-04.pdf>).

Reduced Petroleum Dependence

Passed in 2000, AB 2076 instructs CARB and the CEC to develop and adopt recommendations for the governor and the legislature about a California strategy to reduce petroleum dependence. In response, CARB and the CEC produced a report that proposed and recommended a strategy to reduce California's demand for on-road gasoline and diesel to 15 percent below the 2003 demand level by 2020, and to maintain that level for the foreseeable future. As part of this strategy, the report identified mid-term options, which could be fully implemented in the 2010 to 2020 timeframe that highlighted natural gas in two ways. First, the report prominently suggested the use of natural gas-derived Fischer-Tropsch fuel as a 33 percent blending agent in diesel to reduce petroleum usage by 6 to 7 percent. Second, although not as prominently, it mentions that the expanded use of LNG and CNG in heavy-duty vehicles appears attractive and could provide reductions in petroleum usage at a net societal benefit.

In addition to recommending a reduction in the state's demand for petroleum, the CARB and CEC report also recommended that, regardless of how petroleum reduction is achieved, a minimum percentage of the fuel used in California should come from non-petroleum sources. It recommends that the governor and legislature establish a goal to increase the use of non-petroleum fuels to 20 percent of on-road fuel consumption by 2020 and to 30 percent by 2030, thereby helping achieve the overall petroleum demand reduction goal.

The California Legislature has yet to take action on the CARB and CEC recommendations. If, however, the recommendations are pursued, there may be a slight incentive for dairy farmers to produce biomethane that could be used as a fuel to help meet the bill's non-petroleum fuel targets.

State Fleet Energy Consumption Reduction Goal

State Bill 1170 (2001) established a policy goal to reduce energy consumption of state fleets. California state fleets are directed to develop and adopt (1) fuel efficiency specifications for the use of state vehicles that will reduce energy consumption of the state fleet at least 10% by 2005 and (2) air pollution emission specifications requiring light-duty vehicles acquired by state fleets to meet or exceed the state's ultra-low-emission vehicle (ULEV) standards, a requirement that can be accomplished through the use of natural gas vehicles.

Government Policies and Incentives for Alternative Fuel Vehicles

As discussed above, there are a number of policies and programs that encourage the use of alternative vehicular fuels, though few of them provide specific incentives for biomethane use and production. In addition, there are both federal and state policies and incentives that mandate or encourage the use of alternate fuel vehicles. These programs could indirectly enhance biomethane production and use as a vehicle fuel, although few would provide direct incentives.

Federal Policies and Incentives for Alternative Fuel Vehicles

The Energy Policy Act (EPAct) of 1992 set a national goal of 30 percent alternative fuel use in vehicles by 2010. It required various public fleets to purchase alternative fuel vehicles, although it does not directly require the purchase of alternative fuel. For example, the State and Alternative Fuel Provider Fleets Program requires fleets covered by the program to purchase alternative fuel vehicles as part of their annual light-duty-vehicle acquisitions.

The EPAct of 1992 provided tax deductions of as much as $50,000 for a clean-fuel heavy-duty vehicle, $2,000 for a passenger vehicle, and $100,000 for a clean-fuel refueling property. Clean fuels are defined as natural gas, liquefied natural gas, liquefied petroleum gas, hydrogen, electricity, and any fuel that is at least 85% alcohol (i.e., ethanol) or ester (i.e., biodiesel) (IRS, 2004, p. 48). These deductions and credits ended December 31, 2004.

There are a variety of other federal programs that require or support the purchase of alternative fuel vehicles, including vehicles that will run on natural gas and biomethane. These include the Federal Transit Administration's Clean Fuels Grant Program to accelerate the use of low-emission buses and the US EPA's Clean Fuel Fleet Program that requires fleets in cities with air quality problems to incorporate vehicles that meet clean emission standards (see <http://www.eere.energy.gov/cleancities/progs/afdc/search_state.cgi?afdc/US>). Alternative fuels include ethanol, E85, natural gas, and "fuels (other than alcohol) derived from biological materials (including neat biodiesel)" and electricity (Federal Register, Vol. 61, No. 51, March 14, 1996, page 10653). After passage of EPAct, the American Soybean Association wanted to add mixtures that include biodiesel to the program. In 1998, the EPAct was amended to allow entities that are required to have alternative fuel vehicles in their fleet get credit for vehicles that use B20. The final rule was issued in 2001. This has been the major factor in the growth of the U.S. biodiesel market, which increased from 500,000 gallons in 1999 to 2,000,000 gallons in 2001 to an estimated 25,000,000 gallons in 2003 (see National Biodiesel Board website <http://www.biodiesel.org/resources/faqs/default.shtm>).

Farm legislation during 1996 to 2001 provided for producer payments for increased bioenergy production in the form of ethanol and biodiesel but did not include biodiesel derived from animal by-products and fats, oils, and greases. The 2002 Farm Bill expanded the definition to include biodiesel from these sources.

Table 6-3 summarizes the existing federal policies and incentives for increased use of alternative fuel vehicles and ranks them according to their estimated value for stimulating growth of the biomethane industry. Each of these policies or programs is described in more detail below.

Table 6-3 Federal Policies and Programs that Encourage Use of Alternative Fuel Vehicles, Ranked According to Presumed Impact on Growth of Biomethane Industry

Policy/Program	Value	Explanation
EPAct: State and Alternative Fuel Provider Rule	Low	Requires states and alternative fuel providers to make AFVs a minimum percentage of vehicle fleet acquisitions. This rule does not provide specific incentives for natural gas vehicle purchases, much less renewable methane use. The majority of vehicles purchased under this program are E85 “flexible fuel” vehicles (65 percent of the state and alternative fuel provider fleets). CNG vehicles make up 24% of the state and alternative fuel provider fleets.
EPAct: Federal Fleet Rule	Low	Requires the federal government to make AFVs a minimum percentage of vehicle fleet acquisitions. It also requires these fleets to reduce their petroleum consumption. This rule does not provide specific incentives for natural gas vehicle purchases or renewable methane use. The majority of vehicles purchased under this program are E85 “flexible fuel” vehicles (78 percent of the federal fleet). CNG vehicles make up 21% of the federal fleet.
Federal Income Tax Deduction	Medium	Tax deduction for clean fuel vehicles. Includes natural gas, but no specific incentive for renewable methane. Expired January 1, 2005.
The Congestion Mitigation and Air Quality Improvement Program	Low	Funding for projects and programs that reduce transportation related emissions. Various fuels and technologies can qualify. No specific incentive for renewable methane.
EPA “Clean School Bus USA” Program	Low	Only 20 buses. Various fuels and technologies can qualify. No specific incentive for renewable methane.

High = Provides substantial incentives for both natural gas vehicle use and biomethane production.
Medium = Gives adequate incentives for either increased natural gas vehicle use or increased biomethane production, but not for both.
Low = Inadequate incentives for increased natural gas vehicle use or increased biomethane production.

Energy Policy Act of 1992

As discussed above, the EPAct was passed by Congress to reduce the nation’s dependence on imported petroleum by requiring state, government, and alternative fuel provider fleets to acquire alternative fuel vehicles, which are capable of operating on non-petroleum fuels. Several rules regarding alternative fuel vehicles have been promulgated under this act.

State and Alternative Fuel Provider Rule

As of 2001, the State and Alternative Fuel Provider Rule requires that 75% of new light-duty vehicles for state fleets and 90% for alternative fuel providers must be alternative fuel vehicles. Compliance with this rule is required of state government and alternative fuel provider fleets that operate, lease, or control 50 or more light-duty vehicles within the USA. Of those 50 vehicles, at least 20 must be used primarily within a single metropolitan statistical area or consolidated metropolitan statistical area. In California, the affected metropolitan areas are Bakersfield, Fresno, Los Angeles/Riverside/Orange County, Modesto, Sacramento, Salinas, San Diego, San Francisco/Oakland/San Jose, Santa Barbara/Santa Maria/Lompoc, and Stockton/Lodi.

Federal Fleet Rule

According to the Federal Fleet Rule, from 1999 forward 75% of a federal fleet's light-duty vehicle acquisitions (in fleets covered by the program) must be alternative fuel vehicles. Furthermore, through a combination of AFV acquisitions, increased alternative fuel use in AFVs, improved efficiency in non-AFV acquisitions, and improvements in overall fleet operating efficiencies, agencies were required to decrease the annual petroleum consumption of federal fleets by 20% from 1999 to 2005.

Federal Income Tax Deduction

A $2,000 to $50,000 federal income tax deduction from gross income is available for the incremental cost to purchase or convert qualified clean fuel vehicles. This full federal deduction is allowed for vehicles placed into service after June 30, 1993 and before January 1, 2006. The maximum allowable deductions are as follows, based on vehicle class:

- Truck or van, gross vehicle weight (GVW) 10,000 to 26,000 lb: $5,000
- Truck or van, GVW more than 26,000 lb: $50,000
- Bus with seating capacity of 20+ adults: $50,000
- All other on-road vehicles: $2,000

Additionally, a tax deduction of up to $100,000 can be claimed for clean fuel refueling sites (including electricity). This deduction is allowed for sites placed into service after June 30, 1993 and before January 1, 2006.

Vehicles and sites placed in service in 2006 will receive 25% of the amounts indicated above. No clean fuel vehicle or sites deduction is available for vehicles or sites placed in service after December 31, 2006.

Clean School Bus USA Program

In 2004, Congress allocated $5,000,000 for school bus retrofit and replacement grants through this program, and in June of the same year, the US EPA announced the selection of 20 projects eligible for funding. The program advocates clean diesel technologies and fuels as well as buses that run on CNG.

The Congestion Mitigation and Air Quality Improvement Program

The Congestion Mitigation and Air Quality program funds projects and programs that will reduce transportation-related emissions in non-attainment and maintenance areas. Along with natural gas vehicle projects, funding opportunities exist for diesel engine retrofit projects.

California Programs Alternative Fuel Vehicles

California also has an alternative fuel vehicle program, related to the federal program that encourages the purchase of alternative fuel vehicles. This program focuses on methanol and methanol blends, ethanol and ethanol blends, compressed natural gas, liquefied petroleum gas, and hydrogen. Specifically, the CARB's alternative fuel regulations state that, ". . . 'alternative fuel' means any fuel which is commonly or commercially known or sold as one of the following: M-100 fuel methanol, M-85 fuel methanol, E-100 fuel ethanol, E-85 fuel ethanol, compressed natural gas, liquefied petroleum gas, or hydrogen." (CCR, Title 13, Section 2290 (a) (1)).

Compressed natural gas is defined by its chemical specifications (CCR, Title 13, Section 2292.5). As long as it meets those specifications, compressed biomethane should qualify as compressed natural gas. It is not clear if LNG or LBM qualify. If not, advocates of biomethane that want biomethane to qualify as a clean alternative fuel can petition CARB to get it added to the list (CCR, Title 13, Section 2317).

California has a variety of incentives for super-ultra-low-emission vehicles (SULEV) that run on alternative fuels.[1] For example, single occupants driving SULEV vehicles that use alternative fuels (including, it is assumed, biomethane) are allowed to use car pool lanes. Some localities allow free metered parking (see <http://www.driveclean.ca.gov/en/gv/incentives/index.asp>). Public agencies in the San Francisco Bay Area may get as much as $5,000 from the Air District's Vehicle Incentive Program for the purchase of a SULEV, PZEV (partial zero-emission vehicle) or ZEV (zero-emission vehicle) that runs on natural gas, propane, hydrogen, electricity, or hybrid electricity (see Bay Area Air Quality Management District, Vehicle Incentive Program <http://www.baaqmd.gov/pln/grants_and_incentives/vip/index.asp>). The San Joaquin District

[1] For a general discussion of California incentives see US DOE, Clean Cities Program Review of California Incentives at <http://www.eere.energy.gov/afdc/progs/state_summary.cgi?afdc/CA>.

will provide as much as $40,000 per vehicle for the purchase of new on-road heavy-duty vehicles such as transit buses that run on compressed natural gas or liquefied petroleum gas (SJAPCD, 2003). Vehicles running on ethanol or biodiesel do not qualify for either the Bay Area or San Joaquin District programs.

Table 6-4 summarizes existing California programs for encouraging alternative fuel vehicles and indicates their probable impact on the development and use of biomethane as an alternative fuel. Individual programs are discussed below.

Table 6-4 California Programs that Promote the Use of Alternative Fuel Vehicles

Program	Value	Reason
Tax Deductions	Medium	Exempts AFVs, including natural gas vehicles, from vehicle license fee. No specific incentive for renewable methane.
Bay Area Programs	Medium	Financial incentives for AFVs. No specific incentive for renewable methane.
Carl Moyer Memorial Air Standards Attainment Program	Low	Natural gas vehicles can qualify towards this program, but so can clean diesel technologies. No specific incentive for renewable methane.
California Alternative Fuel Programs	Low	Encourages the purchase of various alternative fuel vehicles, including compressed natural gas vehicles. No specific incentive for biomethane.
The Lower Emission School Bus Program	Low	Only 36 buses. Various fuels and technologies can qualify. No specific incentive for renewable methane.
HOV Lane Privileges	Medium	Allow single occupant SULEV AFVs to drive in HOV lane. No specific incentive for renewable methane.
San Joaquin Valley District Heavy Duty Engine Incentive Program	Low	Natural gas vehicles can qualify towards this program, but so can clean diesel technologies. No specific incentive for renewable methane.
Sacramento Metro District Heavy Duty Vehicle Incentive Program	Low	Natural gas vehicles can qualify towards this program, but so can clean diesel technologies. No specific incentive for renewable methane.
South Coast District Fleet Rules	Medium	Mandates the purchase of natural gas vehicles. No specific incentive for renewable methane.

HOV = High occupancy vehicle.
SULEV = Super ultra low-emission vehicle.
AFV = Alternative fuel vehicle.
High = Provides substantial incentives for both natural gas vehicle use and biomethane production.
Medium = Gives adequate incentives for either natural gas vehicle use or biomethane production, but not for both.
Low = Inadequate incentives for natural gas vehicle use or biomethane production.

Tax Deductions

To help equalize the vehicle license fee for AFVs and conventional fuel vehicles, the incremental cost of the purchase of an alternative fuel vehicle is exempt from the vehicle license fee (of 2%). This reduction applies towards new, light-duty AFVs that are certified to meet or exceed ULEV standards. This program runs from January 1, 1999 to January 1, 2009 (California Revenue and Taxation Code, Section 10759.5).

Bay Area Air Quality Management District Programs

The Bay Area Air Quality Management District (Bay Area District) offers several programs to provide incentives for clean-fuel vehicles, with an emphasis on public agency fleets. The Vehicle Incentive Program offers incentives to public agencies that purchase alternative fuel vehicles with a GVW of 10,000 lb or less. Qualifying vehicles must be certified as ULEV, SULEV II, or ZEV. Incentives range from $1,000 to $5,000 per vehicle. A total of $500,000 is available in FY 2004/05. Another Bay Area District initiative, the Transportation Fund for Clean Air program, offers incentives to cover the incremental cost of alternative fuel heavy-duty vehicles.

Carl Moyer Memorial Air Standards Attainment Program

By focusing on NO_x and PM emissions, the Carl Moyer program, administered by CARB, provides funds on an incentive basis for the incremental cost of engines that are cleaner than required and certified to meet low NO_x emission standards (this includes natural gas engines). Eligible projects include cleaner on-road, off-road, marine, locomotive, and stationary agricultural pump engines, as well as forklifts, airport ground support equipment, and auxiliary power units. About $33.1 million in funding was available for FY 2004 through participating air pollution control and air quality management districts. No maximum grant amount per vehicle is specified, but in the first three years of the program's operation, which was established in 1999 by Chapter 923, around 48% of funding was focused on alternative fuels.

Lower-Emission School Bus Program

Assembly Bill 425 (Statutes of 2002, Chapter 379) mandates that 20% of the Proposition 40 funds made available to CARB are allocated for the acquisition of "clean, safe, school buses for use in California's public schools that serve pupils in kindergarten and grades 1 to 12, inclusive." For FY 2003-2004, $4.6 million was available for the purchase of new school buses, which was enough to purchase about 36 buses statewide.

High-Occupancy Vehicle Lane Privileges

Starting July 1, 2000, certain alternative fuel vehicles were allowed to use high-occupancy vehicle (HOV) lanes, regardless of the number of occupants in the vehicle (California Vehicle Code Sections 5205.5 and 21655.9). To claim this privilege, an identification sticker must first be obtained from the California Department of Motor Vehicles (DMV).

San Joaquin Valley Unified Air Pollution Control District

The San Joaquin District administers the Heavy-Duty Engine Emission-Reduction Incentive Program, which provides incentive funds for the differential cost (up to $40,000 per vehicle) associated with reduced emission technology (as compared to the cost of conventional technology) for heavy-duty vehicles with a GVW over 14,000 lbs. Eligible funding categories include heavy-duty on-road vehicles, off-road vehicles, locomotives, marine vessels, electric forklifts, electric airport ground support equipment, and stationary agricultural irrigation pump engines. Eligible fuel types include natural gas, among others.

Sacramento Metropolitan Air Quality Management District

The Sacramento Metropolitan Air Quality Management District also has a Heavy-Duty Low-Emission Vehicle Incentive program that offers a variety of financial incentives to entities that lower NO_x emissions from heavy-duty vehicles (both on- and off-road). The incentives include the purchase of new natural-gas and other alternative fuel vehicles. Private businesses and public agencies in the six-county Sacramento federal ozone non-attainment area are eligible to apply for this program

South Coast Air Quality Management District

The South Coast District has many rules that mandate the purchase of cleaner, natural gas vehicles (SCAQMD Fleet Rules 1191-1196, 1186.1). The vehicles covered include on-road light- and medium-duty public fleet vehicles, on-road heavy-duty public fleet vehicles, on-road transit buses, residential and commercial refuse collection vehicles, airport ground access vehicles, school buses, and sweepers. In 2004, however, the U.S. Supreme Court disallowed the portion of the South Coast District fleet rules regarding private fleet purchases of certain kinds of heavy-duty vehicles due to a legal jurisdictional issue. While there is a strong effort underway to effectively reinstate the rules via a state mechanism, the Supreme Court action has at least temporarily removed one of the primary drivers for sales of certain kinds of heavy-duty natural gas fuel vehicles in California. Given the potential instability of the current situation, it is difficult to predict the overall effect on the California natural gas vehicle market.

Summary and Conclusions

Renewable electricity, ethanol, and biodiesel are supported by direct financial incentives and mandates that increase their usage. Biomethane receives no direct financial incentives, however, as an alternative fuel, biomethane can qualify for some of the benefits available to alternative fuels. The federal government has programs to promote farm-based and rural renewable energy, and biomethane projects can compete for such awards. In addition, biomethane research and development funds are available through competitive grant programs.

California is committed to renewable electricity and has a variety of programs that provide direct benefits including the California Self Generation Incentive Program, the Renewable Resources Trust Fund, net metering, and requirements under the Renewable Portfolio Standard to purchase renewable electricity. Both the federal and California governments are committed to research and development programs that support renewable electricity from biomass and renewable fuels from biomass. The federal government's efforts are concentrated in the Farm Bill of 2002. California efforts for biomass electricity are funded through the Public Energy Research Program. California has a new Public Interest Natural Gas Energy Research Program that can fund biogas and biomethane research.

When biogas created by an anaerobic digester system is combusted to generate electricity, the generator can earn incentives under federal, and especially, California renewable electricity programs. When biogas is used to create biomethane that will be used in vehicles or other applications, it is ineligible for this funding. It is also ineligible for alternative fuel incentives that are provided for ethanol and biodiesel. At present, the best opportunities for biomethane projects from dairy manure are found in the federal Farm Bill of 2002. Farm-based biomethane projects can compete for federal support under various provisions of this bill such as Title II (EQIP), and especially Title IX (Energy), Section 9006 and Section 9008.

Ethanol has direct cash incentives in excise tax exemptions that began in 1978 and have been consistently extended, currently running to 2007. Both ethanol and biodiesel are also supported by producer incentive funds under Farm Bill Section 9010. Most of those funds go to ethanol, which is produced in substantially larger volume than biodiesel. Federal taxpayers provide $250 to $300 million per year of support under these two programs. The ethanol market is also supported by oxygenation mandates under the Clean Air Act amendments of 1990. Ethanol, biodiesel, and in theory, biomethane receive some market support through the alternative fuel program created by the Energy Policy Act of 1992. These opportunities may be expanded if the Energy Policy Act of 2005 is passed.

Vehicles that run on biomethane fulfill alternative vehicle fleet requirements as mandated in federal, state, and local law and should be able to earn various federal, state, and local incentives.

7. Permits and Regulations for a Dairy Biomethane Plant

A facility to upgrade dairy biogas to biomethane has several components that involve permitting and regulations. The dairy itself is subject to a number of air and water quality regulations, which are described in this chapter, whether or not it produces biogas. Some dairies, both new and existing, may be exempt from certain permit requirements based on dairy size, design, and location. In certain situations, dairies may also be subject to regulations other than those discussed in this chapter.

Most California dairies capture their wastewater in on-site lagoons and thus avoid discharging wastewater to water bodies except during severe storms. Until 2003, California dairies were not required to have water permits, but by April 2006 most California dairies will require water permits (CRWQC, 2003). Even if a dairy has a water permit, a new permit is required for the installation of an anaerobic digestion system. If a dairy has a digester that combusts biogas, or upgrades biogas to biomethane, an air permit will be required. Depending on the county, a local administrative permit or conditional use permit may also be required. New dairies or digesters will need to have a building permit prior to construction activities.

Because the focus of this report is on alternate uses of biogas, particularly through upgrading to biomethane, we will not review the permits and regulations required for dairies or anaerobic digesters. Instead our emphasis will be on permits and regulations applicable for installing a biogas upgrading facility and for storing and using biomethane produced by such a facility.

Permits for a Biogas Upgrading Plant

A biogas upgrading facility is subject to federal, state, and local regulatory requirements. Any required water permits are issued by the regional water board. Unless exempted by local regulations, a biogas upgrading plant must obtain an air pollution permit from the local air district. If an upgrading facility uses or disposes of chemicals that are characterized as hazardous wastes, a permit must be obtained from the California Department of Toxic Substance Control (DTSC). Likewise, if the upgrading plant is off-dairy in an industrial area that is not already permitted, the facility must go through the same permitting process as any other stationary industrial facilities.

No specific additional permits are needed by an upgrading facility to compress or liquefy biomethane to produce CBM or LBM. However, there may be emission or safety issues associated with the production of these fuels that require other permitting or approvals.

At the local level, an upgrading facility should verify that it complies with city or county planning ordinances and meets zoning requirements. Facilities must also meet building code requirements and any new construction must be authorized through a building permit. The regional air district, water board, or other local authority must be contacted to determine if an environmental review is necessary under the California Environmental Quality Act (CEQA).

Table 7-1 provides an overview of the permits that may be required for a biogas upgrading (biomethane) plant and the parties responsible for permit issuance. Each type of permit is discussed in more detail below.

Table 7-1 Permitting Information for Biogas Upgrading Plant

Permit or Requirement	Issuer	Needed?
Water permit	Regional water board	
If facility is located on previously permitted site		Not likely
If there is no discharge to water body		No
If there is discharge to receiving body and site is not previously permitted		Yes
Stormwater permit	Regional water board	No
Stormwater construction permit	Regional water board	Maybe
Air permit	Local air district	Yes
Hazardous waste permit	California Department of Toxic Substance Control	Maybe
CEQA process	Lead agency	Maybe
Solid waste permit	Local enforcement agency	No
Use permit based on zoning	County or city	Yes
Building and related permits	County or city	Yes

Water Permits

According to regulations, most dairies in California are confined animal feeding operations (CAFOs) and will be required to apply for NPDES water permits by April 13, 2006 (CRWQCB, 2003). More specifically, the regulations state that dairies with CAFOs that have more than 700 cows, or that have more than 300 cows and discharge wastewater to a water body or have surface water running across the dairy, will need permits, unless they prove that wastewater from their operations never, under any circumstances, enters a water body (US EPA, 2003). In some cases, smaller CAFOs may also require permits.

However these regulations were successfully challenged in a lawsuit, *Waterkeeper Alliance, et al., v. US EPA*, which was decided in the U.S. Court of Appeals, Second Circuit, on February 28, 2005. Among other aspects the Court ruled that CAFOs do not have a duty to apply for NPDES permits or otherwise demonstrate that they have no potential to discharge. It also eliminated the

700 cow threshold. A full analysis of the implications of this decision is beyond the scope of this report.

If a CAFO dairy (or other dairy without an existing water permit) plans to build a biogas upgrading facility, it will typically need a water permit from the regional water board. Even if the dairy has a water permit, the installation of an anaerobic digestion system requires a new water permit for the plant. If the plant will be off-dairy at a centralized site such as a publicly owned treatment works (POTW) that already has a water permit, a separate permit is probably not required. However, if the biogas upgrading facility will discharge to a water body or a POTW, and is at a location that is not otherwise permitted, then it must obtain the appropriate permit from the local regional water board as discussed below.

The statutory basis for federal water permits are the amendments to Federal Water Pollution Control Act of 1972 (P.L. 92-500), also referred to as the Clean Water Act. This act created the National Pollution Discharge Elimination System (NPDES) permit program, which is the basic regulatory structure for *point sources* that discharge pollutants. The NPDES requires all facilities that discharge pollutants into surface water from a point source to obtain a permit. It categorizes pollutants into *conventional pollutants* such as fecal coliform, toxic or *priority pollutants* such as metals or anthropogenic organic chemicals, and *nonconventional pollutants* such as ammonia, nitrogen, and phosphorus.

Publicly owned treatment works, including water or wastewater treatment plants, and industrial facilities are considered point sources. Most agricultural activities are considered *nonpoint sources* of pollution and are thus exempt from NPDES permitting; however, CAFOs (including large dairies) are defined as point sources. Point sources can discharge to bodies of water directly or indirectly. Direct sources discharge wastewater directly into the receiving water body. Indirect sources discharge to a POTW, which in turn discharges into the body of water. If an industrial facility discharge is a direct source, a general NPDES permit is required, but if the facility discharges to a POTW, it is regulated under the National Pretreatment Program (US EPA, 1999a). Stormwater that runs off a facility or construction site into a water body requires an NPDES stormwater permit (US EPA website <http://www.epa.gov/npdes/pubs/101pape.pdf>).

The Clean Water Act allows the US EPA to authorize state governments to permit, administer, and enforce the NPDES program. The US EPA has delegated NPDES permitting to regional boards, thus allowing regional regulation of water discharges. In California, the Porter-Cologne Water Quality Control Act, also known as the California Water Code (CWC), is the principal law governing water quality regulations. The CWC set up the State Water Resources Control Board and the nine regional water quality control boards.

A Water Discharge Requirement Permit, also issued by the regional board, is required for discharges that are not subject to NPDES, such as those affecting groundwater or those from nonpoint sources (e.g., erosion from soil disturbance or waste discharges to land).

Most upgrading plants will not need these water permits because they will be on a CAFO dairy site that already has a water permit. If there is no permit in place and the upgrading plant discharges water to a water body, it will require a general NPDES permit. If the plant connects to a sewer or other system that discharges to a POTW, it will require a permit under the National Pretreatment Program. The Code of Federal Regulations (CFR) lists specific categories of industrial facilities that require stormwater permits (40 CFR 122.26(b)(14)(i)-(ix)). A biomethane plant does not fit into any of the defined categories; therefore, such a plant should not require a stormwater discharge permit. It may, however, require a stormwater construction permit while it is being built.

Air Emission Permits

The Clean Air Acts of 1970 (P.L. 91-604) and 1990 (P.L. 101-549) are the major federal laws that regulate air emissions. This legislation sets standards for air emission regulation and enforcement, and authorizes states to administer the rules.

The criteria air pollutants regulated under the Clean Air Act are ozone (O_3), nitrogen oxide and dioxide (NO_x), carbon monoxide (CO), particulate matter (PM-10 and PM-2.5), sulfur dioxide (SO_x), and lead (Pb). Volatile organic compounds are defined by the Clean Air Act as precursors of ozone, a respiratory toxicant. The 1990 Clean Air Act also regulates the emission of air toxics, currently a list of 188 pollutants (see US EPA air toxics website at <http://www.epa.gov/ttn/atw/188polls.html>).

The Clean Air Act regulations are enforced in California by the local air districts. Most California dairies are located within the San Joaquin Valley Air Pollution Control District (San Joaquin District). In this district, an industrial plant, such as a biogas upgrading facility, that "emits or may emit air contaminants" is required to obtain an air permit, unless it is a facility that is specifically exempted (SJVAPCD, District Rule 2020, Sections 2, 6 and 7; see <http://www.valleyair.org/rules/currntrules/r2020.pdf>). The extensive list of exemptions does not include any descriptions of a biogas upgrading plant or take into consideration similar facilities in this type of agricultural location.

Since a biogas upgrading facility does not actually combust any gases, it is unlikely to release any of the criteria air pollutants other than VOCs. Depending, however, on the type of upgrade technologies used (see Chapter 3), the facility may release air toxics. If the facility will exceed the legal threshold for one or more air toxics, it will be subject to a "New Source Review," a preconstruction permitting program established by the 1977 Clean Air Act Amendments. Thresholds for air toxics vary depending on the particular pollutant and the air basin in which the facility is located. Thresholds are lower in air basins with the worst air quality.

If the dairy combusts biogas for electricity instead of upgrading it to biomethane, it is still required to obtain an air permit because engine combustion of biogas (to generate electricity) produces criteria air pollutants, notably NO_x.

As mentioned, most dairy-based upgrading facilities are likely to be located in the Central Valley (San Joaquin District); the second most likely location would be along California's South Coast (South Coast District). Both of these districts have been classified as nonattainment areas for ozone and particulate matter. Best available control technologies, as defined by the local air district, must be used in nonattainment areas to control criteria air pollutant emissions if total emissions exceed the designated threshold for that pollutant. For an upgrading plant located on-farm, total emissions include those generated from dairy operations, anaerobic digestion, and upgrading processes. In some districts, dairies with upgrading plants may also be required to purchase emission reduction credits.

Hazardous Waste Regulations

The Resources Conservation and Recovery Act (RCRA) of 1976 and its amendments govern the generation, transport, disposal and recycling of hazardous waste. The US EPA has authorized the California DTSC to carry out the RCRA program in California including permitting, inspection, and compliance. If a biogas upgrading plant will handle or produce any hazardous waste products, it must obtain a Hazardous Waste Facilities Permit from the local office of the DTSC. Hazardous chemicals that might be used at biogas upgrading plants, depending on the technology employed, include ethylene glycol.

California Environmental Quality Act Requirements

The construction of a biogas upgrading plant in California will require an approval by one or more public agencies, who in turn will decide if a CEQA review is required. A CEQA review requires the lead public agency on a project to consider and document any environmental impacts, including means of avoiding or mitigating these impacts where feasible. The first step is to perform an "Initial Study" to determine if there will be significant impacts. If none are anticipated, or if they can be avoided or mitigated, the agency can file a Negative Declaration or a Mitigated Negative Declaration. If, however, the impacts will be significant and cannot be avoided or substantially mitigated, an Environmental Impact Report (EIR) will be required (CRA, 2001).

Local Land Use Regulations

Before beginning construction of a biogas upgrading facility, the builder should check with the local city or county planning department to determine any zoning restrictions on the building site. Most dairies are located outside of city boundaries, on properties zoned for agriculture by the local county. Each county has its own zoning regulations that identify the kind of uses allowed in agriculture zonings and the permits required for these uses.

Merced County, for example, specifically allows “Energy Generation Facilities, Wind Farms, Biomass Fuel Manufacturing” in areas zoned for agriculture (County of Merced, 2004, p. 30). If the energy is to be used on-farm the plant requires an administrative permit; if it is to be used off-farm a conditional use permit is needed (County of Merced, 2004). In addition, construction of a biogas upgrading plant will require a building permit. This permit will ensure that the facility meets the local building code and is built to all appropriate safety standards, including seismic and fire standards. Other counties may require additional permits such as grading permits.

Permits for a Centralized Upgrading Facility

A biogas upgrading plant may be a centralized facility. In this case, the manure is hauled or piped to the digester and the digested sludge and effluent may be disposed of off-site or, in the case of liquid effluent, in a water body. Because the facility is considered a point source, an NPDES permit will be required. A permit from the local air district will also be needed, but a solid waste permit will not be necessary unless the facility stores sludge on-site for more than a year or makes compost from the sludge or effluent (Jeff Paalsgard, County of Merced, personal communication, 24 September 2004). If hazardous wastes may be released during the upgrade process, a hazardous waste permit from the California DTSC is required. At the local level, an administrative or conditional use permit will be required and the local agency responsible for these permits will probably require an EIR that identifies issues involved with transport of the dairy manure or digester wastes on public rights-of-way. A building permit will also be required.

Permitting and Regulation of Biomethane Storage and Transport

Biomethane vehicle fuels such as CBM and LBM are subject to the same federal, state, and local standards as their fossil-fuel counterparts, CNG and LNG. The remainder of this chapter discusses the standards and regulations that apply to biomethane when it is kept in on-vehicle storage tanks, transported over-the-road or distributed through a pipeline.

On-Vehicle Storage Systems

On-vehicle fuel delivery and storage systems for compressed and liquefied natural gas (and biomethane) are subject to federal and state motor vehicle safety standards. In addition, there are a number of industry safety standards and codes associated specifically with the design of CNG- and LNG-fueled vehicles. In general, determining which standards are applied is dependent on whether the biomethane fuel is in compressed or liquefied form as well as the type and GVW rating of the vehicle.

Multiple organizations specify safety standards for CNG- and LNG-fueled vehicles. Manufacturers are legally required to comply with federal and state standards as well as those adopted at the municipal level. Some of the major organizations involved with CNG and LNG component/system/vehicle standards are listed below:

- The National Highway Traffic Safety Administration, under the Department of Transportation (DOT), specifies Federal Motor Vehicle Safety Standards. This organization focuses primarily on light-duty passenger vehicles, pickup trucks, school buses, and other non-commercial vehicles.
- The Federal Motor Carrier Safety Administration, also under DOT, specifies Federal Motor Carrier Safety Regulations for commercial vehicles, primarily large trucks and buses.
- State motor vehicle regulations may include requirements for CNG and LNG vehicles, either explicitly or by reference to existing standards.
- The Society of Automotive Engineers specifies U.S. automotive industry design and safety standards including standards for CNG and LNG vehicles.
- The National Fire Protection Association specifies fire safety codes, including CNG and LNG vehicular fuel systems.
- The American National Standards Institute specifies voluntary standards across a range of industries and products including CNG tanks and CNG/LNG fuel system components.

Table 7-2 summarizes the major safety standards pertaining to CNG and LNG vehicles.

Although there are no specific permits required for retrofitting a CNG or LNG fuel system on a vehicle, retrofitters are responsible (e.g., from a liability perspective) for using certified components and systems, installing these components and systems according to manufacturer instructions, and doing so in a way that does not compromise the safety of the original vehicle.

In addition to complying with applicable safety standards, all new and retrofitted vehicles (including CNG- and LNG-fueled vehicles) must be certified to meet exhaust emissions standards. At the federal level, vehicle emissions requirements are specified by the US EPA. The EPA's Federal Test Procedure (FTP) is used to determine compliance with federal emissions requirements:

- *Light-duty vehicles*. Emissions certification involves chassis testing of the entire vehicle. Manufacturers are responsible for complying with exhaust emissions standards.
- *Medium- and heavy-duty vehicles*. Testing is required of the engine only. Manufacturers are responsible for complying with exhaust emissions standards.

The California Air Resources Board is responsible for setting exhaust emissions standards and overseeing emissions certification of vehicles and engines sold in California. California follows the EPA FTP testing procedure but requires chassis-based testing for medium-duty as well as light-duty vehicles.

There are no specific permits associated with emissions certification testing of CNG and LNG vehicles (including retrofits); however, companies performing such tests in California must be approved by the US EPA and CARB.

Table 7-2 Summary of Major Safety Standards for Compressed and Liquefied Natural Gas Vehicles

Standard or Code	Applicability	Comments
FMVSS 303 – Fuel system integrity of compressed natural gas vehicles	CNG vehicles ≤ 10,000 lb GVW School buses	DOT FMVSS for crash test of light-duty vehicle and school bus CNG fuel systems
FMVSS 304 – Compressed natural gas fuel container integrity	CNG vehicles	DOT FMVSS for CNG tanks (light-, medium- and heavy-duty vehicles)
FMCSR, Part 393.65 – All fuel systems	Medium- and heavy-duty commercial trucks and buses including CNG and LNG vehicles	General requirements for fuel systems including CNG and LNG fuel systems
13 CCR 2, Chapter 4, Article 2	CNG fuel systems in 13 CCR 934; LNG fuel systems in 13 CCR 935	California state requirements for CNG and LNG vehicles
SAE J2343 – Recommended practices for LNG-powered heavy-duty trucks	Heavy-duty LNG vehicles	Adopted by reference in CA state requirements for LNG vehicles.
SAE J2406 – CNG-powered medium- and heavy-duty trucks	CNG vehicles > 14,000 lb GVW	---
NFPA 52 – Compressed natural gas (CNG) vehicular fuel system code, 2002	CNG vehicles	---
NFPA 57 – Liquefied natural gas (LNG) vehicular fuel system code, 2002	LNG vehicles	---
ANSI/CSA NGV2-2000 – Basic requirements for compressed natural gas vehicle fuel containers	CNG vehicles	CNG tank requirements in addition to FMVSS 304
ANSI/AGA NGV3I.1-95 – Fuel system components for natural gas powered vehicles	Fuel system components for natural gas vehicles excluding LNG components upstream of vaporizer	Primarily for converted vehicles

FMVSS = Federal Motor Vehicle Safety Standards
LNG = Liquefied natural gas
CNG = Compressed natural gas
CCR = California Code of Regulations
DOT = Department of Transportation
SAE = Society of Automotive Engineers
FMCSR = Federal Motor Carrier Safety Administration
NFPA = National Fire Protection Association
ANSI = American National Standards Institute

Transportation of Biomethane

In Chapter 5, we estimated that the theoretical maximum potential on-farm demand for biomethane would be about 75% of the potential supply from a typical dairy farm, but concluded that this level would not be achieved in practice. The expense to convert all farm equipment and vehicles to run on biomethane is substantial, and even so at least some of the biomethane would have to be used off-farm. Therefore, it would probably not be economically feasible to build on-farm fueling stations (because of the significant capital equipment costs for such stations). To be an economically viable commodity, biomethane produced on dairy farms should be transported to an off-farm fueling station where there is sufficient demand for biomethane fuel.

As discussed in Chapter 4, biomethane can be transported from a dairy farm to an off-farm fueling station in one of four ways:

- Over-the-road transportation, as compressed biomethane
- Over-the-road transportation, as liquefied biomethane
- Distribution via the natural gas pipeline network
- Distribution via dedicated biomethane pipelines ("raw" or partially upgraded biogas may also be transported via dedicated pipelines to a remote biogas upgrading facility)

The regulations pertaining to each of the above transportation/distribution methods are discussed below, along with applicable permitting requirements.

Over-the-Road Transportation of Compressed Biomethane

Regulations pertaining to over-the-road transportation of CNG are assumed to be fully applicable to over-the-road transportation of CBM. These regulations are enforced by the DOT (49 CFR 171 – 180, Hazardous Materials (HAZMAT)). The DOT HAZMAT tables classify CNG as a flammable gas hazardous material (Class 2, Division 2.1).

Vehicles that transport CNG in bulk, often referred to as "tube trailers," are used when over-the-road transportation of CNG (or CBM) is required. Tube trailers are typically class 8 vehicles consisting of a tractor and a trailer that has multiple CNG storage cylinders connected in parallel, often within an enclosed body or metal cage. Since natural gas has a low energy density at standard pressure, practical and economic considerations require that it be compressed to very high pressures (e.g., 3,000 to 3,600 psi) for over-the-road transportation in these storage cylinders.

Some of the critical HAZMAT vehicle requirements for over-the-road transportation of CNG/CBM include:

- Use of DOT-approved tanks (e.g., DOT-3AAX seamless steel cylinders) that do not exceed rated tank pressure
- Less than 0.5 lb water vapor/million scf
- Minimum methane content of 98%
- Appropriate HAZMAT markings, (i.e., markings for Class 2, Division 2.1 flammable gas).

In addition to these requirements, California DMV regulations require that drivers operating CNG bulk transportation vehicles possess a Class A commercial driver's license with endorsements for driving tank vehicles that contain hazardous materials.

Over-the-Road Transportation of Liquefied Biomethane

The regulations pertaining to over-the-road transportation of LNG are assumed to be fully applicable to over-the-road transportation of LBM (49 CFR 171 – 180, Hazardous Materials). Since LNG is a liquefied version of natural gas, DOT HAZMAT tables classify it as a flammable gas hazardous material (Class 2, Division 2.1).

Bulk LNG is transported in LNG tankers, typically class 8 vehicles consisting of a tractor towing a 10,000 gallon tanker. Because it is liquid, and therefore denser than CNG, LNG is transported at lower pressures (e.g., 20 to 150 psi); however it is a cryogenic liquid and must be kept at extremely low temperatures (e.g., around -260° F). This requires the use of insulated, double-walled tankers and special equipment capable of operating under extremely low temperature conditions. Some of the critical HAZMAT vehicle requirements for over-the-road transportation of LNG (and therefore, LBG) include:

- DOT-approved tanks (e.g., double-walled, insulated steel tank)
- Two, independent pressure-relief systems
- Appropriate HAZMAT markings (i.e., markings for Class 2, Division 2.1 flammable gas)
- Maximum one-way travel time marking

In addition to these requirements, California DMV regulations require that drivers operating LNG bulk transportation vehicles must possess a Class A California driver's license with endorsements for driving tank vehicles that contain hazardous materials.

Distribution via Natural Gas Pipeline Network

We are currently unaware of any federal, state, or local regulations expressly prohibiting the distribution of biomethane via the natural gas pipeline network; however in practice, this has been attempted only once in the USA (at the King County South Wastewater Treatment Plant in Renton, Washington). California law requires the CPUC to regulate the use of biomethane from landfills (landfill gas) because of its vinyl chloride content. These regulations set extremely stringent standards for use of biomethane from landfill gas in a natural gas pipeline.

Local natural gas distribution networks (i.e., mains and service pipelines) are owned by local gas utilities (regulated/investor-owned or municipal), which distribute the gas to customers but do not own the gas production facilities. These utilities require that any gas transported through their systems conform to specific gas quality and interchangeability requirements at the point of receipt.

The two major regulated gas utilities in California are PG&E and SoCalGas; these utilities provide natural gas for most of northern and southern California, respectively. Default gas quality and interchangeability requirements are set forth in PG&E's Rule 21 and SoCalGas's Rule 30 (although these requirements may be superseded by specific agreements). Key default requirements are summarized in Table 7-3.

Table 7-3 Basic Pipeline Quality Standards for Major California Distributors

Gas Component or Characteristic	Pacific Gas and Electric Company	Southern California Gas Company
Carbon dioxide (CO_2)	≤1%	≤3%
Oxygen (O_2)	≤0.1%	≤0.2%
Hydrogen sulfide (H_2S)	≤0.25 grains/100 scf	≤0.25 grains/100 scf
Mercaptan sulfur	≤0.5 grains/100 scf	≤0.3 grains/100 scf
Total sulfur	≤1 grain/100 scf	≤0.75 grains/100 scf
Water (H_2O)	≤7 lb/million scf	≤7 lb/million scf
Total inerts	No requirement	≤4%
Heating value	Specific to receipt point	970 – 1,150 Btu/scf
Landfill gas	Not allowed	No requirement
Temperature	60 – 100º F	50 – 105º F
Gas Interchangeability [a]		
Wobbe number	Specific to receipt point	Specific to receipt point
Lifting index	Specific to receipt point	Specific to receipt point
Flashback index	Specific to receipt point	Specific to receipt point
Yellow tip index	Specific to receipt point	Specific to receipt point

scf = Standard cubic feet

Btu = British thermal units

[a] The various indices— Wobbe number, Lifting index, Flashback index, and Yellow tip index—are all means of determining the gas interchangeability (AGA, 1946)

Additional contractual requirements between a gas utility and a biogas producer would cover quality control, flow metering, and safety items. In all likelihood, a gas utility would resist accepting biomethane from a dairy biogas producer because of gas quality and production reliability concerns. Detailed permitting requirements would be dependent on the contractual arrangement between the biogas producer and the gas utility and would include, for example, the ownership and physical location of the pipeline connection equipment.

Distribution via Dedicated Pipelines

It is unclear whether state and county regulations pertaining to local pipeline distribution of natural gas would be applicable to local distribution of biomethane (or biogas) via dedicated pipelines. Because these dedicated pipelines would be used for relatively short transport distances, regulations governing interstate transmission of natural gas would not apply.

The California Public Utilities Commission regulates distribution of natural gas through regulated gas utilities such as PG&E and SoCalGas. Establishment of an alternate natural gas pipeline network within an established service territory for a regulated utility is normally prohibited (Richard Myers, California Public Utilities Commission, personal communication, 14 December 2004). It is not clear if biogas or biomethane would be considered natural gas if an attempt were made to distribute it via a dedicated pipeline. If the issue arises, a CPUC ruling might be required.

If we assume that biogas and biomethane are not considered to be natural gas from a local distribution perspective, transporting “raw” or pipeline-quality biogas via a dedicated pipeline within a regulated or unregulated service area (e.g., a municipal gas utility service area) would be subject to the standard city and county regulations and permitting process for underground pipe installations. There is another potential obstacle, however; some local regulations specify that permits for underground pipelines carrying gas can only be granted to public utilities. For this reason, having a local utility company as a partner in a biogas/biomethane project could be an important asset during the permitting process.

Obtaining the necessary permits for siting, constructing, and operating dedicated biogas/biomethane pipelines could be an extremely complex, time-consuming, and expensive process depending on the location of the proposed pipelines (i.e., what land they will cross). Permits from state, local, and possibly federal agencies may be required. Some of the key agencies, regulatory bodies, and other parties that may become involved are listed below:

- Bureau of Land Management — responsible for granting natural gas pipeline rights-of-way on federal lands
- Municipal governments — responsible for granting local land-use permits, approval of pipeline siting plans, granting of encroachments on public lands, granting of construction permits, and granting of operating permits
- California state or municipal government agencies — must comply with CEQA, which may require an EIR
- U.S. Army Corp of Engineers — responsible for granting Section 404 permit for pipeline excavation projects that discharge dredged or fill material into public waters (per the Clean Water Act)

- Private property owners — negotiate easements for underground pipelines on their property

Additional federal agencies that may be involved in the permitting and review process include the US EPA, US Fish and Wildlife Service, and the Bureau of Reclamation. State agencies that may be involved include the California Coastal Commission, California Regional Water Quality Review Board, and California Department of Fish and Game.

In the simplest case, where biogas pipelines are to be buried along public rights-of-way (e.g., public roads), the pipeline operator would contact the local department of public works and file for an encroachment permit. If the pipeline crosses private property, the pipeline operator will need to negotiate an easement with the property owners. If the land that the pipeline crosses is not zoned to allow underground biogas pipelines (e.g., agricultural land), the pipeline operator will need to contact local planning commission and apply for a conditional use permit. In addition, any modifications to property owned by the pipeline operator will require a building permit from the city or county planning commission. Finally, the pipeline operator will need to subscribe to the appropriate local "dig alert service" and register the locations of all underground pipelines that it operates.

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.

[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 ft^3)	Total Costs ($ per 1,000 ft^3)
	ft^3/hr	ft^3/d	Total	Annual Amortization (8% for 20 years)	Costs per 1,000 ft^3		
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 ft^3/d	Estimated Capital Costs ($)			Estimated Operation & Maintenance ($ per 1,000 ft^3)	Estimated Total Costs ($/1,000 ft^3)
			Total	Annual Amortization (8% for 20 years)	per 1,000 ft^3 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
		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

[a] 1 gal of LBM = 84 ft^3 methane
[b] 1 DGE of LBM = 140 ft^3 methane

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 Category	**Cost ($per 1,000 ft^3) Low**	**Cost ($per 1,000 ft^3) 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.

9. Developing a Biomethane Industry

To be successful a biomethane enterprise must address two main issues, the production of biomethane from organic waste, and the distribution system that will deliver that biomethane to a user. This chapter discusses some of the broad issues related to development of the biomethane industry in the USA. It also reviews the eight steps needed to develop a successful business plan for a biomethane enterprise, and describes five scenarios for potential biomethane projects.

When this study was designed, we believed that the key barrier to producing biomethane from dairy biogas was the lack of economies of scale in a dairy-sized upgrading plant. As our research—including firsthand observation of operations in Sweden—progressed, however, we learned that the small size of dairy operations is only half of the problem. The other half is the need for a distribution system and a market for the fuel.

Thus, to be a viable economic venture, a dairy plant that produces biomethane must be part of an integrated industry that includes all of these activities:

- Gathering the feedstock
- Producing biogas by anaerobic digestion
- Upgrading of biogas to biomethane
- Storing biomethane
- Transporting biomethane
- Using biomethane

Lessons from Sweden

In June 2004, several of the authors of this report joined a small California delegation on an educational tour of the Swedish biogas industry. Sweden is the world leader in the use of biomethane as a transportation fuel. During our week long tour we visited five biomethane facilities and met with many organizations (WestStart-CALSTART, 2004). They have 2,300 vehicles, mostly buses, running on biomethane. Biomethane has proven more reliable than natural gas because it is upgraded to a higher standard (Ichiro Sugioka, personal communication, June 10, 2005).

Swedish experience demonstrates that a viable biomethane industry is possible. The Swedes have about 20 biomethane plants of various sizes. In general, these are centralized plants, run by public agencies, which use a variety of biogas upgrade technologies and use different organic feedstocks, not just manure, in their digesters. This co-digestion of wastes improves production yields.

It is important to note, however, that the economics in Sweden are much more favorable for a biomethane industry than they are in the USA. Sweden has no fossil fuel industry of its own and all natural gas is imported. Automotive fuel is more expensive. Greenhouse gas emissions are highly taxed. Public policy is very committed to energy efficiency, reduced dependence on imported fossil fuel, and reduction of greenhouse gas emissions. Swedes are committed to recycling and to reducing or eliminating the use of landfills. The country also has a very high level of cross-industry cooperation and government support for alternative fuels.

The most important lesson we learned during our trip to Sweden was that no biomethane plant should be built until a market for the biomethane has been established and a distribution system designed that can move the biomethane to the market. Drivers of alternative fuel vehicles are not going to detour long distances for fuel; the biomethane must be transported to a location that is convenient for refueling. The Swedish operations depend largely on dedicated pipelines to move biomethane to fueling stations; trucks are typically used only as an interim measure until production volume is sufficient to support a pipeline.

Why Should the Public Support the Biomethane Industry?

As Chapter 8 revealed, the current economics for development of the biomethane industry in the USA are challenging if there is no public subsidy. We feel, however, that there are a number of valid reasons to support the development of this industry through publicly funded subsidies, regulation, or tax incentives. Such subsidies and incentives are always necessary to develop a new source of renewable energy or an alternative transportation fuel.

A society such as ours that is heavily dependent on fossil fuel energy should be actively developing a wide variety of alternative energy resources. We cannot always predict which technologies will prove the most viable for our future needs. To preserve our ability to respond to changing future conditions, however, we need to invest in research and development and to build pilot plants for a variety of these technologies.

Biomethane production addresses California’s commitment to renewable energy and to reducing dependence on petroleum. Development of a dairy biomethane industry would help to stimulate California’s economy, particularly its rural economy. Biomethane production provides a series of environmental benefits both during the production process and because it can be substituted for fossil fuels. Development of biomethane production technologies and markets today will ensure future preparedness for the growth of this industry should conditions arise that make the production and use of biomethane a more financially viable and/or necessary option.

Energy Independence and Renewable Fuel

The development of a biomethane industry supports state and federal policy by reducing dependence on imported oil and, more generally, on a finite global supply of fossil fuel. Reduced dependence on imported energy increases our national security. Replacing imported energy with domestically produced biomethane develops and supports our economy, especially our rural economy. Even if biomethane costs more than imported oil, the use of locally produced energy keeps our money at home and helps to support our rural communities instead of transferring wealth to Saudi Arabia and other oil producers.

California's Renewable Portfolio Standard and similar programs in other states demonstrate a commitment to increasing renewable electrical generation as a proportion of the total electrical mix. Renewable electricity promotes improved air quality, reduces GHG emissions, reduces dependence on imported energy, and preserves finite supplies of fossil fuels.

California's dependence on foreign energy sources for electrical generation (other than Canada) is modest. However, California, as well as the nation, is highly dependent on imported oil from relatively unstable countries for vehicle fuel. California legislators have begun to address this issue. Assembly Bill 2076, which became law in 2000, directed the California Energy Commission and the California Air Resources Board to develop a California Strategy to Reduce Petroleum Dependence. This will include statewide strategies to reduce the growth rate of gasoline and diesel fuel usage, and to increase the use of "nonpetroleum based fuels." Biomethane is one such fuel.

A number of existing federal laws aim to reduce petroleum dependency by supporting the use of ethanol and biodiesel; more laws with this goal are currently being developed. Biomethane serves the same purpose as ethanol and biodiesel and its use should be supported in new legislation. The proposed Energy Policy Act of 2005 would establish a national renewable fuel mandate and includes biomethane (although described in different terms).

Future Fuel Shortages and Increased Prices for Fossil Fuels

The economics of biomethane production will improve in the face of rising fossil fuel prices. Fossil fuels are a limited resource that will only become more expensive over time. Recent predictions by respected petroleum geologists indicate a decline in world peak oil production, which could occur before 2010 (see <http://www.peakoil.net/>). This could have staggering implications for world energy prices. Because of their uneven distribution and use worldwide, there is also an associated risk of supply interruption due to political upheaval (such as happened in 1979 from the overthrow of the Shah of Iran).

When supply is interrupted or threatened, higher prices are a certainty. We can better prepare for shortages if we develop renewable domestic alternatives. As prices rise, domestic sources of renewable automotive fuel will become more valuable and more cost competitive. Biomethane needs to be developed as an additional alternative fuel, alongside ethanol and biodiesel.

Environmental Benefits

There are a number of environmental benefits associated with a biogas upgrading plant that produces biomethane. Methane generated by dairy waste and enteric fermentation makes up about 1% of California's total anthropogenic GHG emissions. On dairies that use flush systems to manage manure, an anaerobic digester collects methane that would otherwise be released to the environment. Whether the methane is used for electricity generation or for biomethane, its combustion reduces GHG emissions (even though CH_4 combustion releases CO_2, another GHG, the harmful effects of methane are 21 times greater than those of CO_2, thus the overall net effect is a 21:1 improvement in GHG emissions).

VOCs are an ozone precursor. Research is underway to determine the quantity of VOCs in the biogas generated from dairy manure. Whatever the quantity, the VOCs in the biogas are largely destroyed when biogas is collected and combusted, or when it is upgraded to biomethane and combusted in engines. Biogas combustion creates NO_x, another ozone precursor, and is expensive to control because of the impurities in biogas. Biomethane, however, can be burned in very low NO_x microturbines, or in internal combustion engines that, if properly equipped with catalytic controls, will generate very low levels of NO_x.

Many dairy digesters are built because neighbors complain about dairy odors; digesters reduce these odors substantially. Because they break down manure and other organic material, they also reduce the number of flies. Plug-flow and complete-mix digesters reduce pathogens and weed seeds in the effluent. The whole system improves manure management and wastewater handling on the dairy.

These benefits have an economic value, even though current market conditions in the USA make it hard to quantify that value. In countries that have approved the Kyoto Treaty, reductions in GHG emissions can be bought and sold or traded at an established market value. In the USA, VOC reductions can be traded as ERCs, although it is currently difficult for dairies to participate in ERC markets. The economic benefit of odor reduction is difficult to value, but is nonetheless real. In some cases, odor reduction allows dairies at the urban rural interface to continue operating when political pressure from unhappy neighbors might otherwise be used to close down the dairy.

Further environmental benefits are achieved by the substitution of biomethane in engines for petroleum or natural gas. Biomethane produces no net GHG emissions; the CO_2 released by its combustion represents the product of recent biological processes. In contrast, petroleum and natural gas release GHGs that were captured eons ago, thus introducing an imbalance in the current system.

Greenhouse gases are not currently regulated in the USA, although some states are beginning to address these emissions. California, for example, passed AB 1493, which aims to reduce GHG emissions from vehicle tailpipe emissions. Under federal law, large landfills are required to capture and combust their landfill gas. A state initiative for dairies to reduce GHG emissions by capturing and combusting biogas is under consideration; it would be a very costly proposition for California dairies. Similarly, the San Joaquin and South Coast Air Districts may require dairies to capture and combust biogas to reduce VOC emissions. A viable biomethane industry would allow dairies to recoup some of the costs associated with methane collection and would mitigate their opposition to these requirements.

Eight Steps to a Successful Biomethane Enterprise

A business plan for a successful biomethane enterprise should demonstrate that the following have been researched and, where possible, completed or obtained:

- Buyer for the biomethane
- Supply of organic waste
- Distribution system—pipeline or storage and subsequent over-the-road transport
- Location for biomethane plant
- Technology and operating plan
- Financial plan
- Permitting and regulatory analysis
- Construction plan

Step 1: Find a Buyer for the Biomethane

The Swedish tour made it clear to us that a biomethane developer must have a firm buyer before building a plant. As discussed in Chapter 5 of this report, a dairy cannot use all the biomethane it can produce for on-farm purposes. Converting agricultural pumps, refrigeration, and vehicles to run on biomethane is costly in terms of both time and money. At a typical dairy, even if all of equipment was converted to run on biomethane, facility production would still outstrip demand.

Thus, a dairy upgrading plant needs to find an off-farm market for its biomethane. As part of this project, a special study focused on finding specific locations in the San Joaquin Valley where dairies were concentrated in proximity to CNG fueling stations and other potential biomethane markets. The resulting report is attached as Appendix G; some of the details are summarized below.

Potential Biomethane Markets in the San Joaquin Valley

There are 20 CNG fueling stations in the San Joaquin Valley. Those stations located closest to clusters of dairy farms, however, have a very small demand. For example, the CNG fueling station in Tulare, which is in the midst of what may be the largest concentration of cows in the world, pumps only 84,000 GGE a year of CNG (10 million ft^3/year or about 27,600 ft^3/day). A

1,000-cow dairy could meet this need, but a biomethane plant that small would not be economically feasible.

This demand could be increased if the community committed itself to increasing its CNG fleet. Since the Central Valley has serious air pollution problems, a community might find it worthwhile, and might find public funding, to replace its diesel bus fleet with CNG buses. In this case, it could contract with local dairies to provide the CBM for the buses.

In addition to fueling stations, there are a number of industrial users in the Valley, including cheese plants, which use a significant quantity of natural gas. For example, the CP International plant in Tulare uses 140,000 ft^3/day of natural gas. It would take more than 4,500 cows to produce this much biomethane. Appendix G identifies a number of other such plants in the area.

Other Potential Markets

If a biomethane plant were located on the distribution arm of a public natural gas pipeline, and if it could overcome any regulatory issues and meet utility requirements, it could pay to *wheel* the gas through the pipeline and sell it to an industrial user or perhaps to a local power utility.

Biomethane could be converted to LBM and used as a substitute for LNG. This product can be trucked more competitively than CNG, since it does not compete with gas delivered via a pipeline. (Almost no LNG is produced in California; instead it is trucked into California from out of state.)

Biomethane could be also be used, instead of biogas, to generate electricity. Using biomethane to generate electricity has two advantages over using biogas. First, it can be used in engines that do not produce NO_x: this is important because future regulations to control NO_x emissions in California may make biogas-generated electricity very expensive. Second, it can be stored to provide valuable peaking power, although this opportunity is limited by the high cost of storage.

Finally, biomethane could be a feedstock for other liquid fuel products such as methanol or fuels produced through the Fischer Tropsch process. Potentially, dairy biomethane could substitute for natural gas as a feedstock for hydrogen, although the technical problems associated with this use are greater than for most of the other uses. With the current administration’s focus on the hydrogen highway, this source of renewable hydrogen may attract a lot of interest. Highway 99, which runs down the San Joaquin Valley, could become California’s Hydrogen Highway.

Step 2: Obtain Feedstock for the Anaerobic Digester

This report focuses on dairy manure as a feedstock for on-farm or centralized anaerobic digesters. The biomethane plants we visited in Sweden use a variety of feedstocks, based on what is available in the area. As Chapter 1 demonstrates, there are other feedstocks available in California, such as poultry and swine manure, field and seed residue, vegetable residue, slaughterhouse waste, food processing waste, and slaughterhouse waste. Multiple feedstocks can increase biogas volume and yield, but may require careful monitoring to keep the process healthy. Also, the transport of off-farm wastes to an on-farm anaerobic digester may be subject to additional regulations.

Step 3: Determine Means of Transport

Conceivably, there are several steps in the biomethane production process that may require the transport of feedstocks, wastes, or products to or from the facility. The need for transport depends on a number of factors including location of the facility (on-farm vs. centralized), the use of off-farm feedstock, and the final market.

Organic wastes from dairies, food plants, or similar industries make up the feedstock for the anaerobic digester. On California dairies that use flush systems to manage manure, the feedstock will normally be used on-site since it is mostly water, and therefore is too expensive to move. However, most dairies in the Chino basin in Southern California manage their manure wastes with a scrape system. Because of its lower moisture content, this manure is less expensive to transport than liquid wastes and is trucked to a centralized anaerobic digester at the Inland Empire Utility Agency in Chino. Trucking is only economically feasible for wastes generated a short distance from the processing site, typically less than 5 miles. The facilities in Sweden were all centralized and all trucked in the organic waste product that fed the anaerobic digester.

After biogas is produced from a digester, it must be conveyed to the upgrading plant for biomethane production. In Sweden, the upgrading plants were located next to the anaerobic digester. However, it would be possible to transport the biogas to a centralized location using private pipelines. A centralized upgrading plant that accepted biogas from multiple digesters would allow for greater economies of scale in the biomethane production process. As an example, the Inland Empire Utility Agency in Chino pipes biogas from the digester to the electrical generator (less than 2 miles), and one large dairy in California pipes biogas across its farm almost 1 mile to its electrical generator.

Finally, the biomethane must be transported to market. If the biomethane plant is located on the natural gas grid, using the existing public natural gas pipeline would be the most efficient and cost-effective way to move the biomethane. Distribution via the natural gas grid would eliminate the need to have the biomethane plant in proximity to end users and would also eliminate any need to store the biomethane. In Seattle, the King County wastewater treatment plant transports biomethane produced from digester gas in the local gas utility’s pipeline. Since biomethane is chemically equivalent to natural gas this does not cause any problems. However, in California regulation and resistance from the utilities will make this access more difficult and expensive.

A second alternative is to build a private pipeline to transport the biomethane. Pipelines cost $100,000 to $250,000 per mile, and are less expensive when they do not cross public rights-of-way. Private pipelines eliminate the need for storage at the point of production, although storage would probably be required at the delivery site, especially if it is a fueling station.

The third alternative is to truck the biomethane. This requires compressing or liquefying the biomethane and storing it at the point of production. Stand-alone storage can be avoided if there is enough trucking capacity to always have a truck available for filling. Trucking is more cost competitive if the product is liquefied (i.e., LBM).

Step 4: Locate the Upgrading Plant

The first three steps all revolve around location issues: Where is the buyer? Where is the feedstock? How will the end product be transported to the buyer? The answers to these questions will determine where the upgrading (biomethane) plant should be located. If access to a public gas pipeline is not available, cost considerations require the feedstock, the buyer, the digester, and the biomethane plant to be within a few miles of each other. However, in the case of liquefied biomethane the buyer and the plant can be at a considerable distance.

The most promising locations will have a number of large dairies located in proximity to a CNG fueling station and/or to industrial users of natural gas. Proximity to landfills or to wastewater treatment plants can also be useful, because these facilities can produce large volumes of biogas and could be a good location for a centralized biomethane plant. Also, if the upgrading facility is in a non-attainment area for ozone and particulate matter, public subsidies might be available if it can be shown that the facility will help reduce these emissions.

Appendix G focuses on possible locations in the San Joaquin Valley, a non-attainment area for ozone and particulate matter. Seven counties in the Valley produce 72% of the state's milk. Various items were considered in the preparation of this appendix: databases on dairies, and the locations of CNG fueling stations, industrial gas users, landfills and wastewater treatment plants, were examined to determine optimal locations for upgrading facilities.

Four promising locations were identified in the San Joaquin Valley, the cities of Tulare, Visalia, Modesto, and Hanford (Appendix G). These four areas all have a high concentration of dairies and markets. Potential biomethane developers should review this document for its conclusions as well as for the methodology used. For example, if a developer wishes to locate a facility outside the San Joaquin Valley, he/she could use a similar methodology to review other regions of the State such as the Inland Empire or the Sacramento Valley.

Step 5: Select a Technology and Prepare an Operating Plan

Chapters 2 and 3 of this report (and Appendices A and B) review the various technology alternatives for anaerobic digesting and biogas upgrading. There are three main technologies for dairy anaerobic digestion, several technologies for removing the hydrogen sulfide, and a number of technologies for removing the carbon dioxide. A business plan for a biomethane facility needs to review these technologies in more detail to determine which are most suitable for the planned application. In this process the developer should consider European experiences, especially that of Sweden, which has the largest number of upgrading plants in the world. A review of products and package plants is also needed; for example, several firms are marketing small-scale, skid-mounted biogas upgrading plants.

A technology plan should consider operational requirements as well as performance and capital costs. Some very efficient technologies may require more sophisticated operational management; others may be less efficient but more robust. A large on-farm or a centralized plant may be a better venue for more sophisticated solutions, while smaller farm-based plants should probably choose robustness and ease of maintenance/operation over yields. Whatever technology the developer selects, the technology and operating plan should consider staffing needs.

Step 6: Develop a Financial Model and Locate Potential Financing

As discussed, the first dairy upgrading plants, like other pioneering renewable energy technologies, are not likely to be cost effective without public subsidies. A pro forma financial model needs to be developed that considers account revenues and expenses including operating, maintenance, transportation, and storage costs. Current natural gas prices are at an historical high, but natural gas and electricity prices are highly volatile. Without a long-term fixed price contract, discount rates must consider future price volatility. A capital plan should include permitting and other transaction costs involved in building the plant. To gain public support, the developer should try to quantify and value environmental and other societal benefits. The financial model will help determine the size of the needed public subsidy, while establishing the value of the societal benefits will demonstrate the contribution that the plant can make to the community and help convince decision-makers that a subsidy is warranted.

The developer also needs to identify potential funding sources. Unfortunately, as discussed in Chapter 6, most subsidies and tax benefits are designed either for renewable electricity or for two specific alternate fuels, ethanol and biodiesel. Nevertheless, some potential funding sources for biomethane projects do exist. Also, if community support can be developed, other funding sources, such as local economic development funds, may be tapped.

Step 7: Identify Permitting Requirements and Develop a Permitting Plan

A biomethane plant will require permits, as discussed in Chapter 7. Since the first such plants in California will be pioneering enterprises, the developers will face a great deal of regulatory scrutiny. A CEQA review is likely to be required. Some counties will be more cooperative than others. The developer will need to communicate the societal benefits from the plant. Acquiring the necessary permits will be a substantial effort, and money and time must be designated for this task. If the process proves to be especially difficult, it will add direct costs and cause expensive delays, which would increase the cost estimates provided in Chapter 8.

Step 8: Select a Designer and Contractor and Build the Facility

A competent plant designer and contractor are critical to a successful facility. The anaerobic digester and the biomethane plant may be built by different designers and contractors, but it needs to be a coordinated effort. Many designers claim that they can build good anaerobic digesters because they have built digesters at publicly owned treatment works, however, in the USA few of these have dairy digester experience. Because the feedstock is a critical component of system design, it is best to find a designer who has experience with the proposed feedstock(s). References for both designers and contractors should be obtained and checked. Experience designing small-scale biomethane plants will be very rare in the USA, so it might be useful to consider European designers as well.

Five Possible Biomethane Plant Projects

Below are short descriptions of five biomethane projects that we consider to have the greatest chance for success from a business perspective.

Project 1: Support Community Vehicle Fleet that Uses Compressed Biomethane

The San Joaquin Valley is a non-attainment area for ozone and particulate matter. A community in the Valley could make a significant environmental contribution by developing an integrated project involving CNG vehicles and a biomethane plant. The community could reduce emissions from diesel buses by substituting CNG buses, and could fuel those buses with CBM produced from manure on a nearby dairy or group of dairies.

At least four San Joaquin communities—Tulare, Visalia, Hanford, and Modesto— have both CNG fueling stations and a nearby dense population of dairies. However, the current CNG fleets in these communities are not large enough to support a biomethane plant. To make such a plant viable, demand for CBM needs to be increased beyond the current level. An integrated project that increased the number of CNG vehicles on the road and used locally produced CBM would capture a number of environmental and energy security benefits. The first community to do this would be a national showcase.

With a fueling station already in place, part of the CBM distribution problem would be solved; however, the existing station(s) would need to be substantially expanded, at a significant cost. Increased demand would come from a new fleet of CNG-fueled municipal vehicles.

A single large dairy could generate the biogas and biomethane on-site and then pump it through a dedicated pipeline or truck it to the fueling station. Trucking (of CBM) is expensive and it should probably be considered only as an interim solution until the volume is sufficient to support a pipeline. Alternatively, several dairies could pool their partially cleaned (i.e., H_2S removal would be done on-farm) biogas and pump it through a dedicated pipeline to a centralized biomethane plant. If the dairies were near a landfill, the biomethane plant could be built at the landfill and could use biogas from the dairies as well as from the landfill gas to produce biomethane. Ideally, the biogas upgrading plant would be very close to the filling station.

If such a facility processed waste from around 8,000 cows, it would cost $3,000,000 to $5,000,000 for anaerobic digestion, the upgrade plant, storage, and piping. Additional costs would be incurred for the purchase of the fleet and for the fueling station at the bus barn. The financing of the biomethane plant would be facilitated if the community committed to purchasing CBM on a long-term contract. Finding an appropriate subsidy for the biomethane plant would take some ingenuity, but could be done.

The societal benefits would include cleaner air from cleaner vehicles, energy security and GHG emission reductions by substituting domestically produced renewable fuel for imported oil, reduced GHG and VOC emissions by capturing and eventually combusting dairy biomethane, odor and fly reduction at the dairy, and pathogen and weed seed reduction from the anaerobic digester.

Project 2: Sell Biomethane Directly to Large Industrial Customer

A number of areas in the San Joaquin Valley have dairies concentrated near sizable industrial users of natural gas. One or more of these industrial users could provide a substantial demand for locally produced biomethane.

As with the previous example, a single large dairy could generate biogas and upgrade it to biomethane on-site and then pump it through a dedicated pipeline or truck it to the industrial user (again, trucking should be considered an interim solution). Several dairies could pool partially cleaned biogas and pump it through a dedicated pipeline to a centralized biomethane plant. Ideally that plant would be very close to the industrial buyer.

This project would be especially useful for industrial users that are located off of the natural gas transmission grid. Because industrial users need a reliable supply of gas, the biomethane plant needs to be robust and storage would be needed at the industrial site to ensure fuel supply when the biomethane plant is not operating.

For many industrial users of natural gas, their main need is for heat. In some applications, heat could be supplied by raw or partially cleaned biogas, without the need to upgrade to biomethane. Even if heat is the only application, concerns about transportation, storage, corrosion, fuel blending, or air emissions may make the biogas unsuitable for an industrial user.

Project costs and benefits would be similar to the first proposed project, except there would be no costs for a vehicle fleet or upgraded fueling station. The financing of the biomethane plant would be facilitated if the industrial user committed to purchasing its output on a long term contract. As with any other pioneering renewable energy project, public subsidies would be needed to make this project feasible.

The societal benefits would include GHG emission reductions by substituting domestically produced renewable fuel for fossil fuel, reduced GHG and VOC emissions by capturing and eventually combusting dairy biomethane, odor and fly reduction at the dairy, and pathogen and weed seed reduction from the anaerobic digester.

Project 3: Distribute Biomethane through Natural Gas Pipeline Grid

If barriers to the use of the natural gas transmission system could be overcome, an on-farm or centralized biomethane plant could sell directly to the local gas utility, or pay to wheel the biomethane to an industrial or municipal customer on the natural gas grid. Of course, the biomethane plant would need to be located along or very close to the distribution line. Since the Central Valley is not well served by natural gas distribution, this option is not practical in some areas, despite the presence of abundant dairies.

The environmental and societal benefits would be similar to the direct sale of biomethane to an industrial customer.

Project 4: Build Liquefied Biomethane Plant

Liquefied biomethane can be used as a direct substitute for LNG. Except for a small PG&E pilot project, all LNG vehicle fuel is trucked into California from out-of-state LNG plants.

A California biomethane plant built to serve the CNG vehicle market has a competitive disadvantage. It has to transport its biomethane, or CBM, to a fueling station and still compete in price with the natural gas delivered via pipeline that already serves the fueling station. A California LBM plant does not have this handicap. In fact, it may have a competitive advantage because it will likely be closer than the out-of-state LNG plants that currently serve the customer.

A dairy LBM plant could be built anywhere in the state where there is a sufficient supply of dairy waste. It could be built at a single large dairy, or it could be operated at a central location by transporting partially cleaned biogas from several nearby dairies through dedicated pipelines to a biomethane plant. If a group of dairies were near a landfill, the LBM plant could be built at the landfill and could use biogas from the dairies as well as landfill gas to produce LBM.

While transportation costs limit a CBM plant to nearby markets, an LBM plant can cost-effectively transport LBM to fueling stations much further away. LBM could also be delivered to liquefied-to-compressed natural gas (LCNG) fueling stations or to customers off the natural gas grid that already receive gas deliveries in the form of LNG.

Most LNG is used in heavy-duty vehicles; California currently has fewer than 1,500 such vehicles. Before an LBM plant is built, the developers must ensure a sufficient demand for its product by contracting with any of a number of fleet fueling stations in the state that could consume the LBM.

The societal benefits from such a plant would be the same as those from the community CBM vehicle fleet project described above.

Project 5: Use Compressed Biomethane to Generate Peak-Load Electricity

Because CBM can be stored (unlike biogas, which cannot be stored at high pressures due to associated corrosion problems and high cost) a biomethane plant could use its fuel to generate peaking electrical power.

The Renewable Portfolio Standard commits California to a substantial increase in renewable electricity. Bids for program funds are evaluated based on "least cost, best fit." There is a Market Referent Price for electricity, and a higher price for peaking power. Renewable energy that can be dispatched to serve peak demand can earn a substantial premium over non-dispatchable renewable energy resources like wind and solar. If this premium were sufficient, storing compressed biomethane to generate peaking power could be cost effective. While the IOUs have not been eager to buy dairy electricity other than through the upcoming RPS process, the municipal utilities, particularly the Sacramento Municipal Utility District, may be more responsive.

To take advantage of the RPS program, the plant would have to be able to dispatch at least 1,000 kW, which would require biogas from about 10,000 cows. A very large single dairy or group of dairies could produce the needed biomethane on-farm or at a location central to several farms. The biomethane could be used to fuel a microturbine, but substantial storage capacity would be needed to ensure fuel availability for peak times.

True peak-load plants can make a profit running as little as 10 percent of the time. The high cost of biomethane storage, however, will require the biomethane plant to operate on a more regular basis, and will thus reduce the proportion of output that can capture the highest wholesale prices (during highest peak loads). The balance between the opportunity to capture peak-load prices and the cost of storing biomethane would need to be carefully evaluated, but it is unlikely that storage capacity of more than one or two weeks would be feasible.

The environmental and societal benefits would be similar to the direct sale to an industrial customer.

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Appendix A

Stoichiometry of the Anaerobic Digestion Process

Biogas from anaerobic digestion of sewage, food processing, animal and other wastes typically contains about 55% to 70% CH_4 and 30% to 45% CO_2. In some cases, much higher CH_4 content are reported, over 70% (see Chapter 2 of main report) and even up to 90% CH_4 in some cases. High methane content in biogas would be desirable, as it would reduce, in some cases even avoid, the need for CO_2 removal from the biogas, and direct utilization (after H_2S and moisture removal) as a vehicular fuels and other applications requiring compression. This Appendix briefly examines the potential for achieving high (>70%) methane content in the biogas as part of the anaerobic digestion process of dairy manures, to reduce or even avoid the need for a separate CO_2 removal operation.

Biogas production from organic substrates involves an internal redox reaction that converts organic molecules to CH_4 and CO_2, the proportion of these gases being dictated by the composition and biodegradability of the substrates, as already briefly discussed above. For the simplest case, the conversion of carbohydrates, such as sugars (e.g., glucose, $C_6H_{12}O_6$) and starch or cellulose ($C_nH_{n-2}O_{n-1}$), an equal amount of CH_4 and CO_4 is produced (50:50 ratio):

$$CnHn\text{-}2On\text{-}1 + nH_2O \rightarrow \tfrac{1}{2}\, nCH_4 + \tfrac{1}{2}nCO_2 \qquad (1)$$

In the case wastes containing proteins or fats, a larger amount of methane is produced, stoichiometrically from the complete degradation of the substrate. For proteins, the process is as follows:

$$C_{10}H_{20}O_6N_2 + 3H_20 \rightarrow 5.5\ CH_4 + 4.5\ CO_2 + 2NH_3 \qquad (2)$$

This yields a CH_4:CO_2 ratio of 55:45; the exact biogas composition will depend on the individual substrate protein.

For fats and vegetable oil (triglycerides), a typical CH_4:CO_2 ratio is 70:30:

$$C_{54}H_{106}O_6 + 28\ H_2O \rightarrow 40\ CH_4 + 17\ CO_2 \qquad (3)$$

These simplified examples can change according to effects from several factors:

- Reactions are often incomplete (typically up to half of the cellulose is refractory to microbial anaerobic degradation, and lignin is completely inert, for example).
- By-products are produced and voided in the digester effluent (e.g., acetic, propionic and other fatty acids and metabolites).
- Bacteria use these reactions to make more bacteria; thus, there is also some biomass produced as part of these metabolic processes.

The last two factors will reduce CH_4 somewhat more compared to CO_2 production, as the by-products and bacterial cells are generally more reduced than the substrates. However, these corrections are relatively minor, as most of the substrate degraded is indeed converted to CH_4 and CO_2 because bacterial biomass yields in anaerobic fermentations are quite low, typically less than 5% of the C in the substrate being converted to bacterial biomass (composition approximately $C_5H_8NO_2$). Incomplete digestion also does not affect gas composition significantly. For a first approximation, therefore, the three above factors can be disregarded for adjusting for expected CH_4:CO_2 ratios.

Thus, the maximum content of CH_4 in biogas produced from anaerobic digestion can only be about 70% when digestion of oils is included; for typical dairy wastes, a methane content of between 55% and 60% is most likely.

Despite this, it is frequently observed that CH_4 concentrations in biogas from dairy manures are typically somewhat above 60%. There are two mechanisms that can explain such an increase in CH_4 content in the biogas, and these could possibly be used to achieve the goal of increasing methane gas production: two phase digestion and CO_2 dissolution in the process water. These are discussed below.

Two-Phase Anaerobic Digestion

Two-phase anaerobic digestion processes have been extensively studied and in a few cases also applied in practice. In such processes, two bioreactors are operated in series, with the initial reactor operated at a much shorter hydraulic retention time (HRT), as little as one tenth or less of the HRT used in a typical single-stage reactor. The second reactor is operated at typical anaerobic digestion HRT, generally over 15 days. Thus, the first reactor is much smaller than the second reactor, in which nearly all conversion to methane occurs.

The essential concept of two-phase digestion is to separate the two main microbiological processes of anaerobic digestion, acidogenesis (production of volatile fatty acids, H_2 and CO_2) and methanogenesis (production of methane from the fatty acids, H_2 and CO_2). These two reactions are carried out by distinct bacterial species and populations, and the two-phase anaerobic digestion process is based on the concept that the operational characteristics of each stage can be adjusted to favor the bacteria: very short HRTs and solids retention times (SRTs), with resulting organic-acid formation and low pH in the first stage; longer HRTs and conversion of the acids to methane (and CO_2) at neutral pH in the second. Thus the aim is to provide an optimal environment for each of these distinct microbial populations, thus allowing an overall faster reaction (e.g., reducing the reactor size of the combined first and second stage compared to conventional systems). Two-phase digestion is also claimed to result in a greater overall yield of methane, as a larger fraction of the substrates will be metabolized and converted to biogas, presumably by action of the more vigorous acidogenic bacteria.

Unfortunately, this concept suffers from a fundamental flaw: the two types of populations work commensally, that is they depend on each other for optimal metabolism. Simply put, the H_2 and acetate (as well as the higher fatty acids) produced by the acid-forming bacteria are strong inhibitors of the metabolism by these bacteria. The methanogens, by removing these “waste” products and converting them to CH_4, perform a most useful and necessary role in the overall process. Indeed, although acidogenic bacteria (at least some populations) tolerate the low pH that develops in the first, short hydraulic retention time, acid-forming reactor of a two-phase process, a low pH does not actually help the process of acidogenesis. In brief, after several decades of research, the advantages of two-phase anaerobic digestion are still to be demonstrated. Indeed, the main advantage claimed for two-phase digestion, the reduction in overall tank sizes, has not been demonstrated, and the operation of two, rather than one, digesters is not an advantage.

It should be noted in this context that many, and in practice perhaps most, of so-called two-phase processes, are in actuality, two-stage processes, where the first stage also produces methane. In these cases the volume ratio of the first and second stages is greater than the approximately 1:10 (or even 1:20) of the second stage, typical of two-phase digestion. Essentially in two-stage processes the first stage acts mainly as a surge tank, sometimes with a liquid recycle loop from the second to the first stage, which would actually defeat the objective of two-phase digestion. Two-stage digestion does, however, reduce short-circuiting, a significant issue with single-stage mixed tank reactors.

For a two-phase digestion, the ideal stoichiometry, for the simple case of carbohydrate breakdown, can theoretically be written as:

First stage: $C_6H_{12}O_6 + 2\ H_2O \rightarrow 4\ H_2 + 2\ C_2H4O_2$ (acetic acid) $+ 2\ CO_2$ (4)

Second stage: $2\ C_2H_4O_2 \rightarrow 2\ CH_4 + 2\ CO_2$ (5)

Overall this does not improve the biogas methane content and reduces methane yields by one third, though it produces an equivalent amount of H_2 fuel.

A great deal of research is ongoing to achieve such a yield of H_2 in the first stage, due to the current popularity of H_2 as a fuel. However, in practice, such high yields would be achievable only under extreme laboratory conditions (e.g., with a large amount of purge gas, to strip H_2 from the first stage, and the use of very high temperature strains, at 180º F). The best H_2 yield that is actually obtained and obtainable is about half this, with the remainder of the sugar substrate being converted into more reduced products (e.g., propionic acid, butyric acid, ethanol, etc.):

First stage: $C_6H_{12}O_6 \rightarrow C_4H_8O_2$ (butyric acid) $+ 2\ CO_2 + 2\ H_2$ (6)

Second stage; $C_4H_8O_2 + H_2O \rightarrow 2.5\ CH_4 + 1.5\ CO_2$ (7)

This raises the content of the methane in the biogas from the second stage to a little over 60% (for this illustrative case), but at a decreased yield of methane (e.g., 2.5 vs. 3 in a single-phase process). Depending on the operating conditions of the first phase, virtually no H_2 is produced in the first stage, resulting in a production of only CO_2 in the first stage and more methane in the second stage. However, in this case the actual amount of net CO_2 produced in the first stage is also reduced, and, thus, no further increase in biogas CH_4 content is likely (although theoretically an increase of up to 75% could be possible).

In principle it would be possible to increase the CH_4 content of biogas by feeding the H_2 produced by the first-phase reactor to the second-phase reactor. Methanogenic bacteria, which dominate the second phase, use H_2 preferentially and at very high rates, converting CO_2 into CH_4. However, this process would only be effective in raising CH_4 content if the H_2 and CO_2 produced in the first stage were separated, which would defeat the purpose of avoiding such separation processes.

In any event, a two-phase process is not applicable to dairy wastes. A two-phase process, and the stoichiometric relationships discussed above, are applicable only to soluble and readily metabolized sugars and starches, possibly some fats and protein, but not to the more difficult to digest particulate, fibrous and other insoluble matter that comprise most of the substrates available for bacterial decomposition in dairy wastes. For dairy wastes there would be essentially no H_2 produced in the first phase of a two-phase process. The advantages of two-phase digestion, though a much promoted process, are modest even when applied to more suitable wastes such as food processing wastes, which are high in sugars or starches. The process should not be considered for dairy wastes.

Removal of Carbon Dioxide During the Digestion Process

The second mechanism that can account for the relatively higher CH_4 content in biogas than would be expected from simple stoichiometry is the dissolution of CO_2 in the digester water. CO_2 is much more soluble than CH_4 in water. At 1 atmosphere pressure (about 14 psi) and ambient temperature (e.g., 21º C, or 70º F) about 1.8 grams per liter (g/l) of CO_2 are dissolved in water compared to about 4 mg/l of CH_4. Gas solubility is proportional to partial pressure, thus, at a 50/50 CH_4:CO_2 ratio, these concentrations would be halved but the relative ratios of the two gases dissolved in water would be the same. This ratio of 400 to 1 between CO_2 to CH_4 dissolution in water is the basis for the water scrubbing process for CO_2 removal (see Chapter 3 of main report). It also accounts for the rather significant amount of CO_2 that exits the digesters dissolved in water and, thus, the enrichment in CH_4 observed in the biogas, compared to what is expected from the above stoichiometric equations.

This can be exemplified by a simple calculation: Assume that a dairy waste with 4 g/l of degradable VS (volatile solids), of which 50% is C, is stoichiometrically (molar basis) converted to equal amounts of CO_2 and CH_4. This would produce 3.7 g/l of CO_2 and 1.25 g/l of CH_4. As more of the CO_2 would remain dissolved in the water, the actual ratio of CO_2: CH_4 in the liquid phase would, at equilibrium, be only about 2 mg of CH_4, a negligible amount, but 0.7 g/l of CO_2, which reduces the amount of CO_2 in the gas phase, from 50/50 to about 55/45 CH_4:CO_2.

In practice, the effluent from a digester is not at equilibrium with the atmosphere above it (e.g., the biogas); more CO_2 and CH_4 are dissolved in the liquid than expected at equilibrium. Although disequilibrium would affect dissolved CO_2 and CH_4 about equally, because of the much higher solubility of CO_2 than CH_4 in the liquid, the recovered biogas would be more enriched in CO_2 than calculated above for the equilibrium case. The "extra" CO_2 (and CH_4) dissolved in the liquid effluent from the digesters would be released to the atmosphere after the liquid effluent leaves the digester. This could more than double the amount of CO_2 produced during the anaerobic digestion process that does not actually enter the biogas phase. In the above example, if the amount of CO_2 dissolved in the water phase were three times higher than at equilibrium, this would give a 2:1 ratio of CH_4:CO_2 in the gas phase, with half the CO_2 produced remaining in the liquid phase. At the same relative disequilibrium, CH_4 losses in the liquid effluent would still be less than 1% of the total produced. A three-fold excess (above that equilibrium with the gas phase) in dissolved gases is well within what is possible for full-scale anaerobic digestion processes. It should, however, be noted that the very long retention times typical of anaerobic digestion processes, in particular dairy manures, means that there is more time for the gas and liquid phase to reach equilibrium. Thus, although the maximum ratio of CH_4:CO_2 that could be achieved just from CO_2 being dissolved in the liquid effluent from the AD process is not clear, it is not likely that it would be much higher than the above projected 2:1 ratio. As this ratio increases the disequilibrium between liquid and gaseous phases increases sharply.

This issue of CO_2 dissolution and disequilibrium has been somewhat neglected in most anaerobic digestion studies, but it can readily account for the frequent observations of relatively high CH_4:CO_2 ratios in biogas in many systems, including from dairy manures, compared to predictions from stoichiometry and equilibrium calculations. Although it does not appear likely that a much higher than 2:1 ratio would actually be achievable, this issue deserves further study.

It should be noted that for laboratory-scale and even small pilot plants, the amount of mixing (agitation) that the bioreactors are normally subjected to is many times greater per unit volume than for large-scale processes, Thus, small, well-mixed systems are typically run much more closely near the gas exchange equilibrium than would be the case for full-scale systems. Consequently, in respect to the ratio of gases in the biogas produced, it is not possible to directly extrapolate laboratory results to full-scale systems.

In a few cases, very high CH_4:CO_2 ratios, about 9:1, have been reported from anaerobic digester processes. These did not involve standard anaerobic digester reactor designs but, rather gas collected from anaerobic lagoons. In these situations, the gas, collected either at the surface or below, was exposed to large amounts of liquid. In particular these reports originate from algal wastewater treatment systems, where algae deplete the water of CO_2, providing a sink for CO_2 produced by the anaerobic digestion process. Thus, in reality, such systems combine anaerobic digester with a water scrubbing process. Although algal ponds can be used for treating anaerobic digester effluents (BOD removal and nutrient capture) and can be of interest in dairy manure management, this technology is still in the development stage. Also, it is not likely that this technology would be as closely integrated with an anaerobic digester process as suggested by proponents of using an in-pond digester process and submerged gas catchers. The most plausible system configuration separates these processes of anaerobic digester and effluent treatment, if required. In any event, this topic is beyond the scope of the present report.

Conclusions

Biogas produced by dairy wastes in typical AD processes is somewhat enriched in CH_4, compared to what would be expected from the metabolic processes of organics degradation. However, the observed and expected enrichment is rather modest, from about 50% to 55% or 60%. There is also a near-doubling of CH_4 to CO_2 ratios, from 1:1 closer to 2:1 (e.g., 66% methane), which is about the maximum that would likely be achievable.

For applications where CO_2 removal is required (e.g., for upgrading to vehicular fuels), CH_4 to CO_2 ratios of over 10:1, typically even above 20:1, would be required. This suggests that there is little point in trying to improve on the anaerobic digester process in this regards, as a CO_2 removal process would not be avoided if the goal is for a higher purity CH_4 fuel. Also, it does not appear that the additional effort that would be required to increase CH_4:CO_2 ratios during the anaerobic digester process could be justified by any savings in the final purification step. Thus, producing a high CH_4 content biogas from dairy manures directly from the anaerobic digestion process is not practical and would not significantly decrease the costs of CO_2 removal required for applications requiring biomethane quality fuel. Thus, post-digestion processes for upgrading biogas to renewable methane should be the main focus.

Appendix B

Detailed Description of the Three Main Dairy Digester Technologies

This appendix reviews and compares covered-lagoon, plug-flow, and complete-mix anaerobic digestion technologies for the quantity and quality of renewable biogas produced. It also presents detailed information and design considerations of these three anaerobic digester technologies available for dairy farms in California.

Description of Covered Lagoon Digester

A cover can be floated on the surface of a properly sized anaerobic lagoon receiving flush manure to recover methane. The most successful arrangement includes two lagoons connected in series to separate biological treatment for biogas production and storage for land application. A variable volume one-cell lagoon designed for both treatment and storage may be covered for biogas recovery. However, a single-cell lagoon cover presents design challenges not found in constant-volume lagoons and will require assistance of professionals familiar with the design, construction and operation of these systems. Figure B-1 shows the components of a covered lagoon digester; Figure B-2 shows an actual system operating in California.

The primary lagoon is anaerobic and operated at a constant volume to maximize biological treatment, methane production, and odor control. The biogas recovery cover is floated on the primary lagoon. Ideally, manure contaminated runoff is bypassed to the secondary lagoon. The secondary lagoon is planned as variable volume storage to receive effluent from the primary lagoon and contaminated runoff to be stored and used for irrigation, recycle flushing, or other purposes.

Temperature is a key factor in planning a covered lagoon. Warm climates require smaller lagoons and have less variation in seasonal gas production. Colder temperatures in northern California will reduce winter methane production. To compensate for reduced temperatures, loading rates are decreased and hydraulic retention time (HRT) is increased. A larger lagoon requires a larger, more costly cover than a smaller lagoon in a warmer climate. Reduced methane yield may decrease the return on investment.

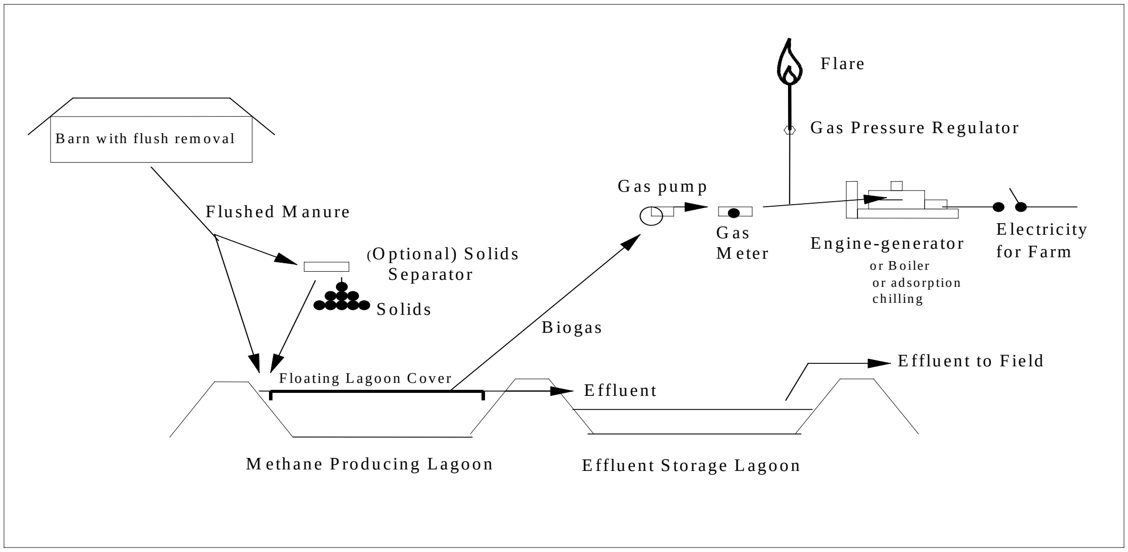


Figure B-1 Covered lagoon system components

Figure B-2 Photograph of Castelanelli Bros. Dairy covered lagoon digester located in Lodi, CA. (source: RCM Digesters, Inc.)

Components of Covered-Lagoon Digester

Solids separator. A gravity solids trap or mechanical separator should be provided between the manure sources and the lagoon.

Lagoons. Two lagoons are preferred; a primary anaerobic waste treatment lagoon and a secondary waste storage lagoon.

Floating lagoon cover. The most effective methane recovery system is a floating cover over all or part of the primary lagoon.

Biogas utilization system. The recovered biogas can be used to produce space heat, hot water, cooling, or electricity.

Covered-Lagoon Design Variables

Soil and foundation. Locate the lagoons on soils of slow-to-moderate permeability or on soils that can seal through sedimentation and biological action. Avoid gravelly soils and shallow soils over fractured or cavernous rock.

Depth. The primary lagoon should be dug where soil and geological conditions allow it to be as deep as possible. Depth is important in proper operation of the primary lagoon and of lesser importance in the secondary lagoon. Deep lagoons help maintain temperatures that promote bacterial growth. Increased depth allows a smaller surface area to minimize rainfall and to cover size, which reduces floating cover costs. The minimum depth of liquid in the primary lagoon should be 12 ft.

Loading rate, hydraulic retention time and sizing of primary lagoon. The primary anaerobic lagoon is sized as the larger of volatile solids loading rate (VSLR) or a minimum HRT. The VSLR is a design number, based primarily on climate, used to size the lagoon to allow adequate time for bacteria in the lagoon to decompose manure.

Volatile solids loading rate. Figure B-3 below shows isopleths for the appropriate loading rates for a constant volume primary lagoon in a two-cell lagoon system.

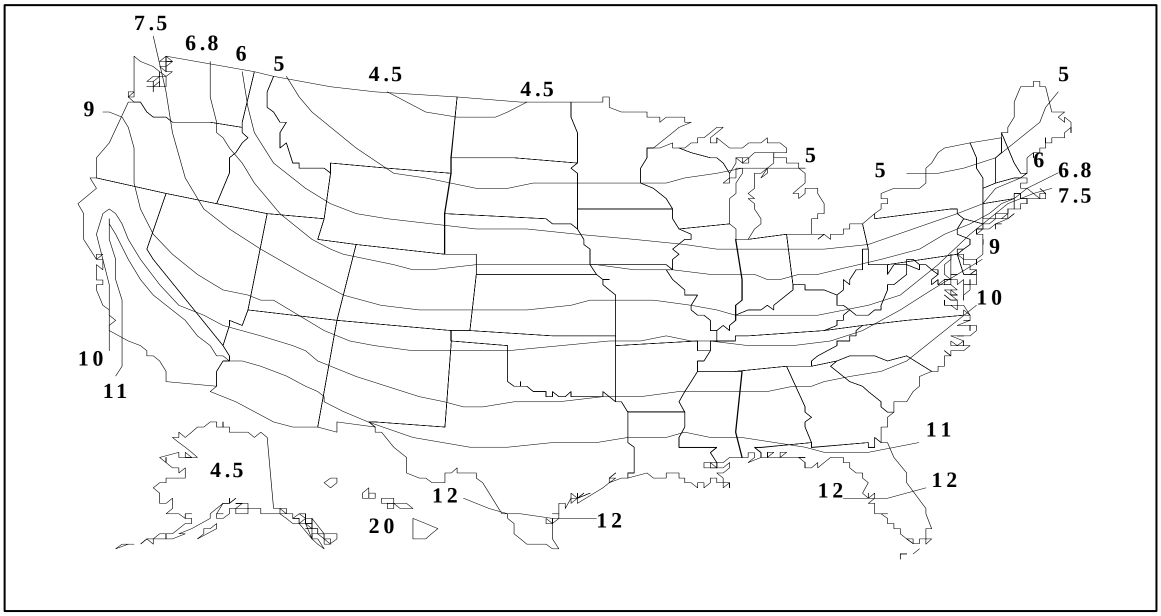


Figure B-3 Covered Anaerobic Lagoon Maximum Loading Rate (lb VS/1,000 ft^3/day) (NRCS, 1996, Code 360, Reference 3)

Minimum hydraulic retention time. The VSLR procedure is appropriate in most cases, however modern farms using large volumes of process water may circulate liquids through a primary lagoon faster than bacteria can decompose it. To avoid this washout, a minimum hydraulic retention time (MINHRT) is used to size the lagoon. Figure B-4 shows MINHRT isopleths.

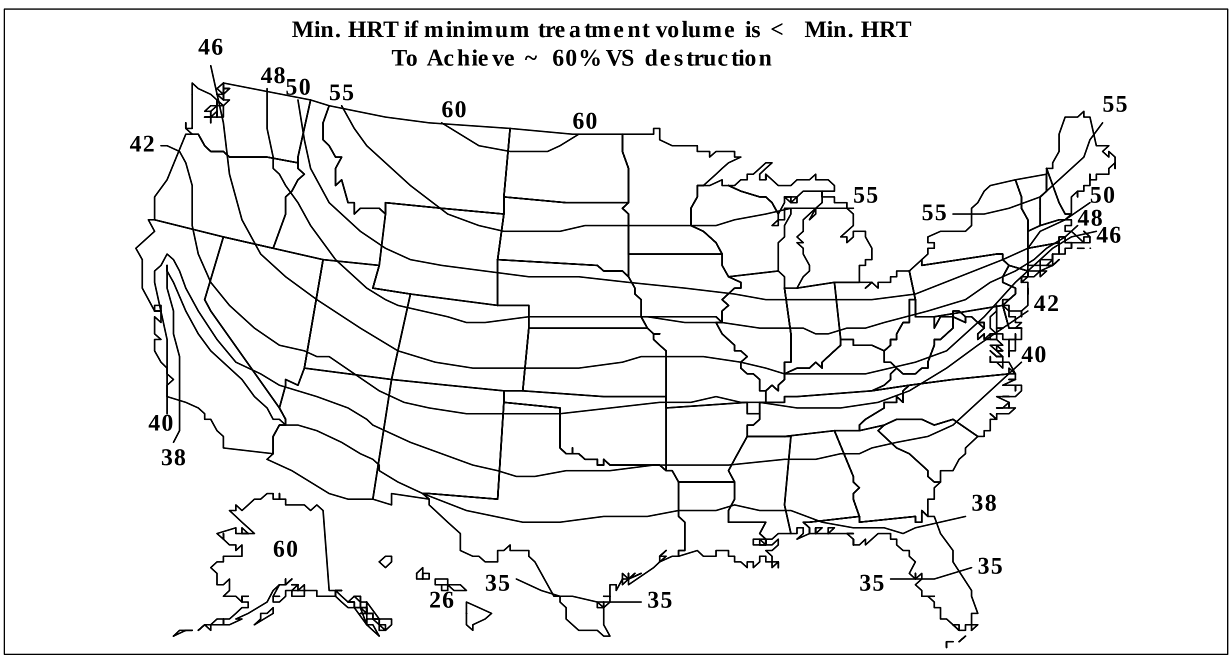


Figure B-4 Covered anaerobic lagoon minimum hydraulic retention times (NRCS, 1996, Code 360, Reference 3)

Primary lagoon inlet and outlet. The primary lagoon inlet and outlet should be located to maximize the distance across the lagoon between them.

Rainfall. Rainfall is not a major factor in determining the potential success of a covered lagoon. In areas of high rainfall, a lagoon cover can be used to collect clean rain falling on the cover and pump it off to a field. In areas of low rainfall, a lagoon cover will limit evaporation and loss of potentially valuable nutrient rich water.

Cover materials. Many types of materials have been used to cover agricultural and industrial lagoons. Floating covers are generally not limited in dimension. A floating cover allows for some gas storage. Cover materials must be: ultraviolet resistant; hydrophobic; tear and puncture resistant; non-toxic to bacteria; and have a bulk density near that of water. Availability of material, serviceability and cost are factors to be considered when choosing a cover material. Thin materials are generally less expensive but may not have the demonstrated or guaranteed life of thicker materials. Fabric reinforced materials may be stronger than unreinforced materials, but material thickness, serviceability, cost and expected life may offset lack of reinforcement.

Cover installation techniques. A lagoon cover can be installed in a variety of ways depending upon site conditions. Table B.1 lists features found in floating methane recovery lagoon covers. Figure B-5 shows typical features of lagoon covers.

Table B-1 Features of a Floating Methane Recovery Lagoon Cover

Feature	Description
Bank Attachment Options	See text and Figure B-5.
Rainfall Management	Rainfall may be pumped off the cover or drained into the lagoon.
Securing Edges of a Floating Cover	The edges of the cover can be buried in a perimeter trench on the lagoon embankment or attached to a concrete wall. Floating edges not secured directly on the embankment need support in place. A corrosion resistant rope or cable is attached to the cover as a tie-down and tied to an anchor point.
Skirting	Portions of the cover floating in the lagoon require a perimeter skirt hanging into the lagoon from the cover.
Anchor Points	Anchor points for cable or rope may be driven metal stakes or treated wood posts.
Float Logs	A grid of flotation logs is attached to the underside of the cover. The float logs may be necessary as gas collection channels, to minimize gas pockets and bubbles under the cover.
Weight Pipes	A grid of weight pipes may be laid on the cover surface to help hold the cover down.
Gas Collection	Biogas bubbles to the surface of the lagoon and migrates across the underside of the cover. A gas pump maintains a vacuum under the cover. A gas collection manifold is attached to the cover. A gastight through-the-cover, through-the-attachment wall or under the buried cover gas pipe carries biogas to a biogas utilization system.

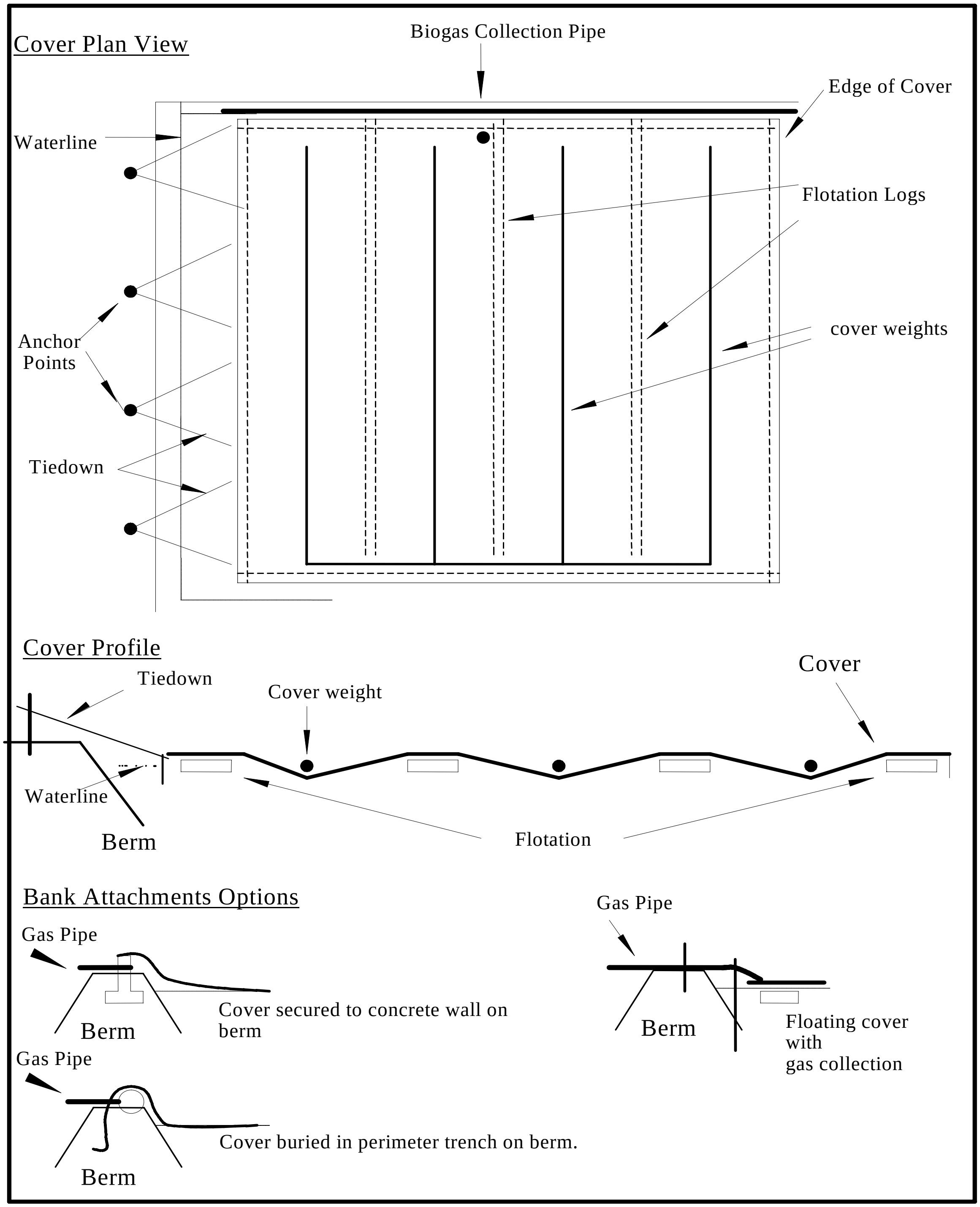


Figure B-5   Typical features of lagoon covers

Full perimeter attachment. The entire lagoon surface is covered and the edges of the material are all attached to the embankment.

Completely floating or partially attached cover. The cover may be secured on the embankment on one to three sides or the whole cover can float within the lagoon. All or some of the sides may stop on the lagoon surface rather than continuing up the embankment.

Operation and Maintenance of Covered-Lagoon Digester

The operation and maintenance of a covered lagoon should be relatively simple.

Primary lagoon — operation. The proper design and construction of a primary lagoon leads to a biologically active lagoon that should perform year round for decades. Any change in operation will most likely be due to a change in farm operation resulting in an altered volatile solids loading or hydraulic load to the lagoon. The owner should make a visual inspection of lagoon level weekly.

Primary lagoon — maintenance. Minimal maintenance of the primary lagoon is expected if the design volatile solids and hydraulic loading rates are not changed. Lagoon banks should be kept free of trees and rodents that may cause embankment failure. Weeds and cover crops should be cut to reduce habitat for insects and rodents. Occasional plugging of inlet and outlets can be expected. Sludge accumulation may require sludge removal every 8 to 15 years. Sludge can be removed by agitating and pumping the lagoon or by draining and scraping the lagoon bottom.

Cover operation. Operating a lagoon cover requires removing the collected biogas from below the cover regularly or continuously. Large bubbles should not be allowed to collect. If the cover is designed to accumulate rainfall for pumpoff, accumulated rainwater should be pumped off.

Cover maintenance. The cover should be visually inspected weekly for rainwater accumulation, tearing, wear, and proper tensioning of attachment ropes. The rainwater pumpoff system should be checked after rainfall and maintained as needed.

Description of Plug-Flow Digester

A plug-flow digester is used to digest manure from ruminant animals (dairy, beef, sheep) that can be collected as a semisolid (10% to 60% solids) daily to weekly with minimal contamination (dirt, gravel, stones, straw) and delivered to a collection point.

Components of Plug-Flow Digester

A plug-flow digester system generally includes a mix tank, a digester tank with heat exchanger and biogas recovery system, an effluent storage structure, and a biogas utilization system. Post digester solids separation is optional. Figure B-6 shows the features of a plug-flow digester system.

Collection/mix tank. A mix tank as described above for a complete digester is used to achieve a solids concentration between 11% and 14% solids.

Plug-flow digester. A plug-flow digester is a heated, in-ground concrete, concrete block or lined rectangular tank. The digester can be covered by a fixed rigid top, a flexible inflatable top or a floating cover to collect and direct biogas to the gas utilization system.

Biogas utilization system. The recovered biogas can be used to produce space heat, hot water, cooling, or electricity.

Solids separator (optional). A mechanical separator may be installed between the plug-flow digester outflow and the effluent storage structure.

Design Criteria and Sizing the Plug-Flow Digester

Location. If a manure pump is installed to pump the 12% solids manure, the digester can be located within a 300 ft radius of the mix tank at a convenient location with good access.

Mix tank. The mix tank can be round, square, or rectangular. A pump may be required to move manure to the plug flow digester.

Hydraulic retention time and sizing of plug-flow digester. A plug-flow digester will function with an HRT from 12 to 80 days. However, an HRT between 15 and 20 days is most commonly used to economically produce 70% to 80% of the ultimate methane yield.

Dimensions. The depth of a plug-flow digester can be between 8 feet and 16 feet depending upon soil conditions and the required tank volume. The width:depth ratio is usually greater than 1 and less than 2.5. The length:width ratio should be between 3.5 and 5.

Heat exchanger: An external heat exchanger or an internal heat exchanger is required to maintain the digesting mixture at the design temperature. Hot water circulated through the heat exchanger is heated using biogas as a fuel for a boiler or waste heat from a biogas fueled engine-generator.

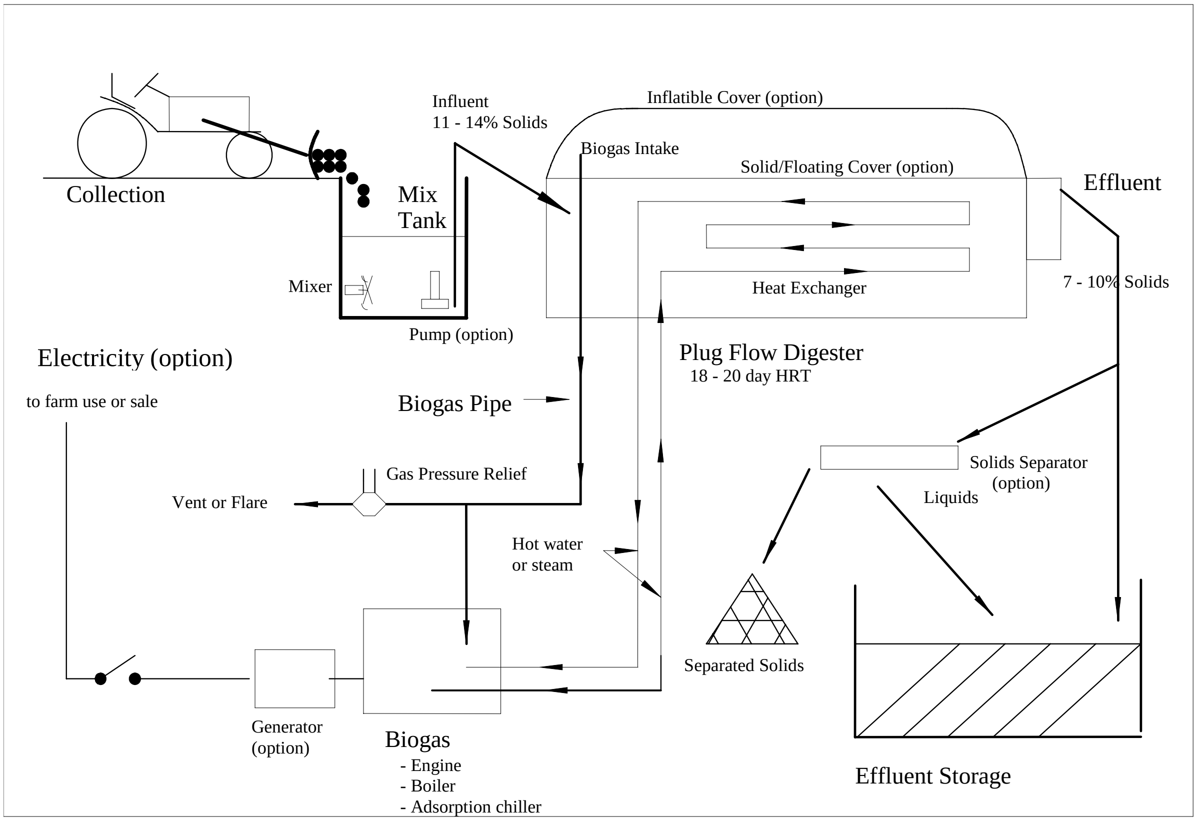


Figure B-6 Features of plug-flow digester system

Operating temperature. The daily temperature fluctuation should be less than 1° F. Most plug flow digesters operate in mesophilic range between 95° to 105° F with an optimum of 100° F. It is possible to operate in the thermophilic range between 135 to 145° F, but the digestion process is subject to upset if not closely monitored.

Insulation. A plug flow digester surface may be insulated to control heat loss.

Construction materials. The digester can be constructed as a lined trench or as a reinforced concrete or block tank.

Methane recovery system and covers. See discussion of methane recovery system above under complete mix digesters.

Description of Complete-Mix Digester

A complete-mix digester is a controlled temperature, constant volume, mechanically mixed, biological treatment unit that anaerobically decomposes medium concentration (3% to 10% solids) animal manures and produces biogas (60% methane and 40% carbon dioxide) and biologically stabilized effluent. Figure B-7 includes general features of a complete-mix digester system.

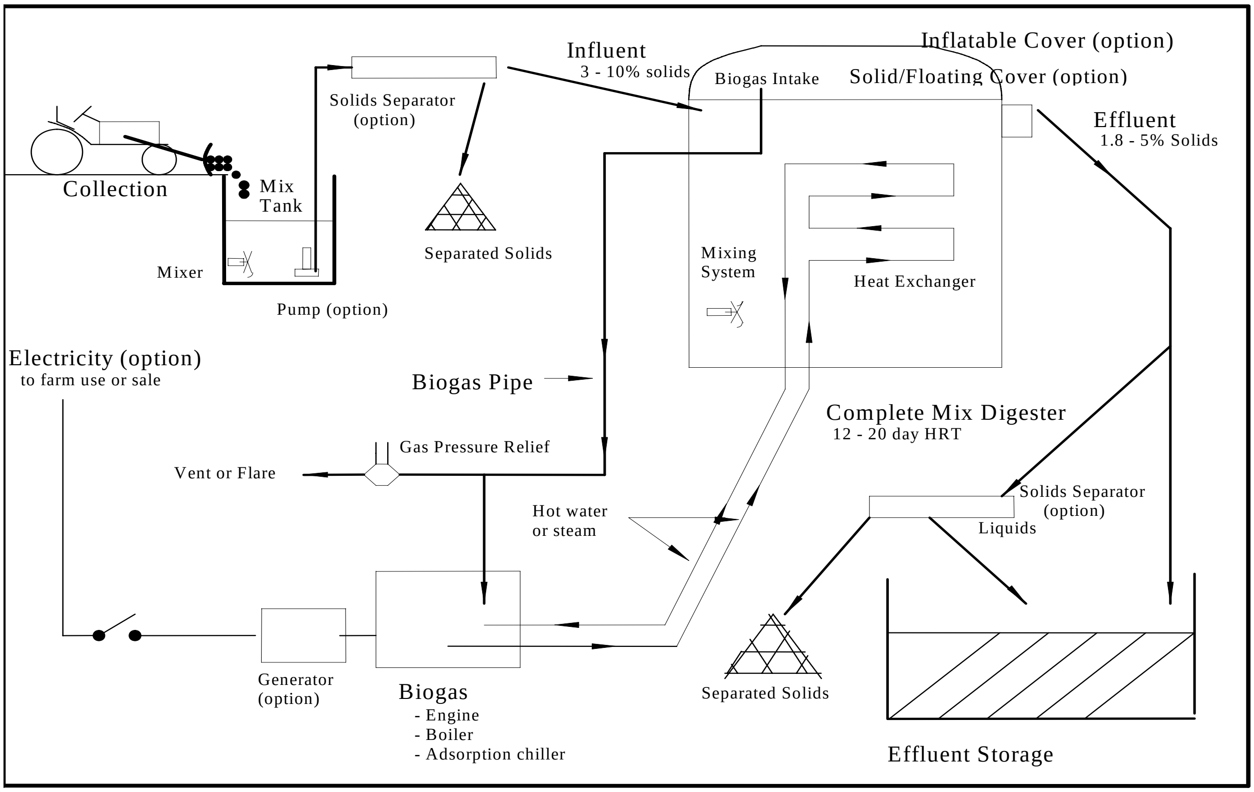


Figure B-7 Components of complete-mix digester

A complete-mix digester is designed to maximize biogas production as an energy source. The optimized anaerobic process results in biological stabilization of the effluent and odor control. The process is part of manure management system and supplemental effluent storage is usually required. Manure contaminated rainfall runoff or excess process water should not be introduced into the complete-mix digester.

Components of Complete-Mix Digester

The components of a complete-mix digester system generally include a mix tank, a digester tank with mixing, heating and biogas recovery systems, an effluent storage structure, and a biogas utilization system. Pre- or post-digester solids separation is optional.

Mix tank. The mix tank is a concrete or metal structure where manure is deposited by a manure collection system. It serves as a control point where water can be added to dry manure or dry manure can be added to dilute manure. Manure is mixed to 3% to 10% solids content prior to introduction into the complete-mix digesters.

Pretreatment. A solids separator may be used to separate solids from influent manure to reduce solids buildup in the digester.

Complete-mix digester. A complete-mix digester is a heated, insulated above ground or in-ground circular, square or rectangular tank with a mixing system. The tank is covered by a fixed solid top, a flexible inflatable top, or a floating cover to collect and direct biogas to the gas utilization system. All covers are gas tight.

Biogas use. The recovered biogas can be used to produce space heat, hot water, cooling, or electricity.

Solids separator (optional): A mechanical separator may be installed after a complete-mix digester to capture fibrous materials fed as roughage to ruminants.

Complete-Mix Digester Design Criteria

Location: A complete-mix digester can be located within a 600 ft radius of the mix tank at a convenient location with good access.

Optimum solids concentration. The operating range for influent solids concentration in a complete-mix digester is 3% to 10% solids. However, 6% to 8% solids is the preferred concentration.

Mix tank. The mix tank can be round, square, or rectangular. A pump may be required to move manure to the digester.

Hydraulic retention time and sizing of complete-mix digester. A complete-mix digester will function with an HRT from 10 to 80 days. However, an HRT between 12 and 20 days is most commonly used to economically produce 60% to 75% of the ultimate methane yield.

Operating temperature. A heat exchange system should maintain the daily temperature fluctuation at less than 0.55^o C (1^o F). Most complete-mix digesters operate in the mesophilic range between 35^o to 41^o C (95^o to 105^o F). It is possible for this type of digester to operate in the thermophilic range between (135^o to 145^o F) but the digestion process is subject to upset if not closely monitored.

Insulation. A complete-mix digester tank may require insulation to control heat loss.

Heat exchanger. An external heat exchanger or an internal heat exchanger is used to heat and maintain the digesting mixture at the design temperature. Hot water or steam circulated through the heat exchanger is heated using a biogas-fueled boiler or waste heat from a biogas fueled engine-generator.

Construction materials. The digester tanks can be concrete or metal.

Mixing. Gas or mechanical mixing is used to stir the digester.

Dimensions. The depth can be between 8 and 40 ft depending upon soil conditions and the required tank volume.

Methane recovery system. A complete-mix digester is covered by a gas tight fixed solid top, a flexible top, or a floating cover to collect and direct biogas to the gas utilization system.

Solid cover. A solid cover is constructed to avoid cracking and leaks. Solid covers should resist corrosion. A solid cover allows for minimal gas storage.

Inflatable Cover. A coated fabric is generally used for inflatable covers. An inflatable cover can be designed for some gas storage. Wind protection may be necessary. The cover must have a gas tight seal. These materials are described in the covered lagoon discussion, above.

Floating cover. A floating cover is designed to lie flat on the digester surface. See discussion of floating covers for covered lagoons, above.

Operation and Maintenance of Complete-Mix and Plug-Flow Digesters

Operation and maintenance of complete-mix and plug-flow digesters is very similar and therefore will be discussed together in this section. Proper operation and maintenance of plug-flow and complete-mix digesters is necessary for successful operation.

Mix tank — operation. On a daily or every other day basis, collectible manure is pushed, dragged or dumped into the mix tank. If necessary, dilution water or drier manure is added to the collected manure and mixed to achieve the design total solids mixture. The mixed manure is released via gravity gate or pumped into the digester.

Mix tank — maintenance. Mix tank maintenance consists of normal maintenance of pumps and mixers per manufacturers recommendations. The mix tank will require occasional cleaning to remove accumulated sand, gravel, steel and wood.

Complete-mix and plug-flow digester — operation. A complete-mix digester is fed hourly to daily, displacing an equal amount of manure from the outlet. A plug-flow digester is fed from the mix tank daily or every other day. The digester heating and mixing system should be checked daily to verify operation.

Complete-mix and plug-flow digester — maintenance. The digester temperature should be checked daily. The effluent outlet and digester gas pressure relief should be checked weekly to be sure that they are operating properly. The heat exchanger pump should be lubricated per the manufacturer’s recommendations. The mixer in a complete mix digester should be lubricated per the manufacturer’s recommendations. Sludge accumulation may require sludge removal every 8 to 10 years.

Cover — maintenance. The cover should be visually inspected weekly for rainwater accumulation, cracks, tearing, wear, and tensioning.

Appendix C

Conversion of Biogas to Biomethanol

Interest in neat methanol as a vehicular fuel has been steady for many years; the “Methanol Institute” promotes this chemical and major energy (oil, gas) companies also have some interest in this fuel. There are claims that methanol-using internal combustion engines reduce air pollution. Methanol is now also being considered as a storage fuel for hydrogen fuel cell cars. Nevertheless, during the past 20 years, no significant market has developed for methanol as fuel, although it is often used as an additive and can be blended with biodiesel to enhance cold weather properties. Methanol has only half the energy content of gasoline; it has a lower vapor pressure than gasoline; it can attack fuel and engine components; and it is toxic. Although these obstacles could be overcome, together with the lack of a methanol vehicle fueling infrastructure, they have limited the potential of this fuel.

Past Unrealized Projects

One company (TerraMeth Industries, Inc. of Walnut Creek, California) proposed building a landfill-gas-to-methanol plant in West Covina, Southern California during the 1990s. Despite legislation that supported the project and several years of trying to find financing, this project did not come to fruition. Another proposed project in Washington State was also abandoned. With the phase-out of MTBE, interest in methanol production waned.

The process for converting dairy manure biogas to biomethanol is challenging, primarily because it would need to be carried out at a scale several orders of magnitude smaller than current processes. For example, the unrealized TerraMeth landfill-gas-to-methanol project would have cost just under $10 million (capital costs) for a facility that produced about 6 million gallons of methanol per year (and this cost is judged optimistic by many who have examined this conversion). An equivalently sized dairy facility would need over 50,000 cows to produce this much gas, which, by industrial standards is actually a very small plant.

The Smithfield Foods Utah Project: From Hog Manure to Biodiesel

A recent example of an animal-manure-to-methanol project is one proposed by Smithfield Foods in Utah. A subsidiary firm, Best Fuels LLC, announced an ambitious $20-million project that would convert the manure from 23 hog farms (with a total of 257,000 finisher pigs) first to biogas and then to methanol for biodiesel production (Figure C-1). The farms were all within a 5-mile radius and the impetus for the project was the difficulty of marketing electricity from biogas produced from the animal manure.

As shown in Figure C-1, manure (about 40,000 tons dry matter/year) collected from swine houses is pumped to a central location, thickened by gravity to about 4.5% solids and digested in inground, heated (95 °F), floating cover digesters. The facility would produce about 1.2 million ft^3/day of biogas.

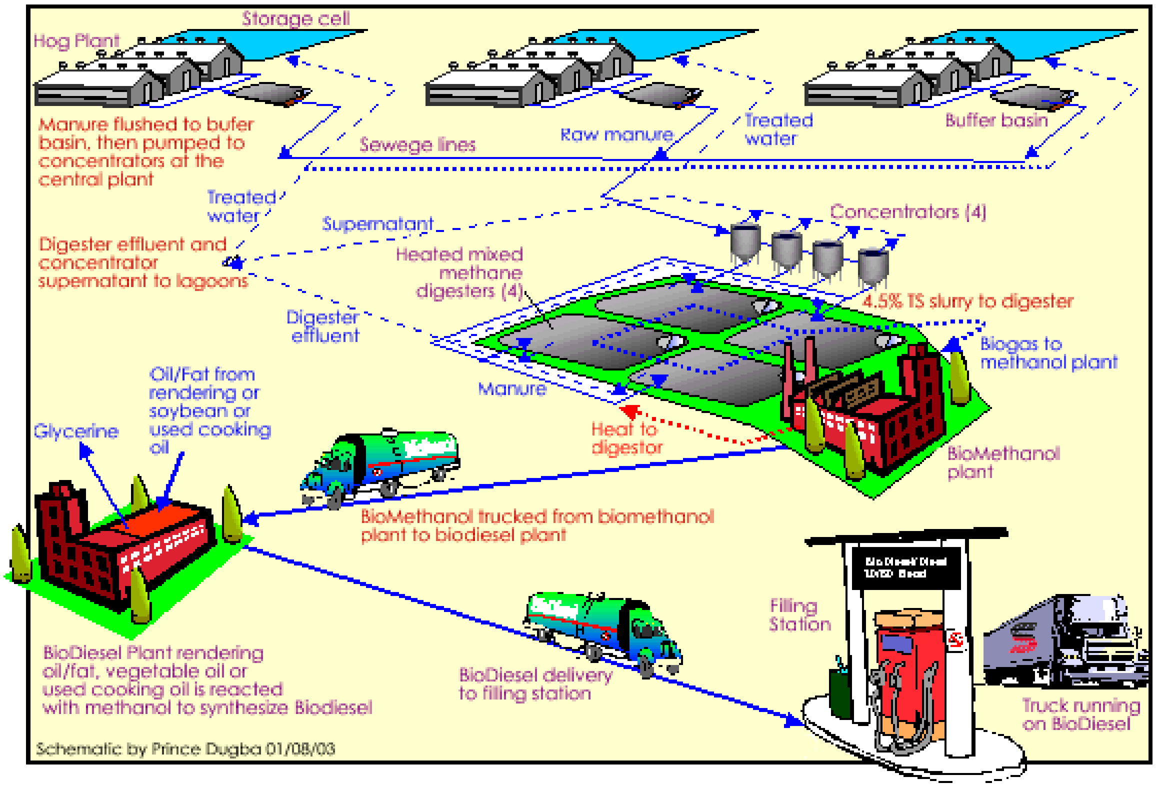


Figure C-1 Project of Best Fuels LLC/Smithfield Foods for Converting Hog Manure to Methanol

The biogas is next pumped to a central plant, where H_2S is removed with sodium hydroxide (NaOH). The gas is converted to methanol in a conventional steam-reforming/water-gas shift reaction followed by high-pressure catalytic methanol synthesis:

$CH_4 + H_2O \text{ --> } CO + 3H_2$ and $CO + H_2O \text{ --> } CO_2 + H_2$ gasification/shift reaction (1)

$CO + 2H_2 \text{ --> } CH_3OH$ or $CO_2 + 3H_2 \text{ --> } CH_3OH + H_2O$ methanol synthesis reactions (2)

The process at the Smithfield site is expected to yield 7,000 gallons of methanol per day. The methanol is used off-site for biodiesel production, expected to yield 40,000 gallons of biodiesel per day. The project literature states, “These processes should be considered industrial-scale processes, thus requiring a highly trained staff and high-tech equipment.”

However, after the initial much publicized announcement of the project no further information has become available. It is the opinion of the authors that if such an approach were even modestly economically attractive, it would have already been implemented under the much more favorable (from an engineering standpoint) opportunities made possible at stranded high-CO_2 natural gas wells. There the quality, quantity, pressure of the gas would much better justify their upgrading and conversion to methanol. It remains to be seen if this project actually moves forward.

Appendix D

Compressed Natural Gas and Liquefied Natural Gas Vehicles Available in California

CNG Vehicles

In 2004, the following types of CNG and LNG vehicles were available in California.

Light-Duty CNG Vehicles

The following types of light-duty CNG vehicles are currently available in California:

- Passenger vehicles
- Pickup trucks
- Passenger vans (including light-duty shuttles)
- Cargo vans

Light-duty CNG vehicle models are currently available from Honda, General Motors, Daimler-Chrysler and Baytech (a CNG vehicle converter specializing in GM vehicles). Ford, which had previously offered several CNG models (including the Crown Victoria sedan used in many CNG taxi fleets), announced in February, 2004 that they were stopping production of all CNG vehicles.

Examples of representative light-duty CNG vehicle types are shown below:

Passenger Vehicles

Honda Civic GX
American Honda Motor Co., Inc.
Four-door dedicated CNG sedan; auto
CVT; 1.7L four cylinder; 8 GGE fuel capacity;
200 mile range
Certification: SULEV

Pickup Trucks

Chevrolet Silverado C2500 Pickup
General Motors Corp.
Dedicated CNG pickup truck; 2WD; 4-speed automatic; regular, extended cab or crew cab; 6.0L V8; 15 GGE fuel capacity; 180 mile range
Certification: ULEV

Passenger Vans

GMC Savana Van
General Motors Corp.
Dedicated CNG van; 8 – 12 passengers; 6.0L V8; 4-speed auto; 20.3 GGE fuel capacity; 320 mile range
Certification: ULEV

Cargo Vans

Chevrolet Express Cargo Van
Baytech Corp.
Dedicated CNG van; 258 ft^3 cargo space; 6.0L V8; 4-speed auto; 20.3 GGE fuel capacity; 320 mile range
Certification: ULEV

Medium- and Heavy-Duty CNG Vehicles

The following types of medium- and heavy-duty CNG vehicles are currently available in California:

- Transit buses
- School buses
- Refuse trucks
- Street sweepers
- Shuttles (medium-duty)
- Trolleys
- Miscellaneous heavy-duty trucks

Medium- and heavy-duty CNG vehicle models are currently available from a variety of truck manufacturers- and vehicle converters. Examples of representative medium and heavy-duty CNG vehicle types are shown below.

Transit Buses

Orion VII CNG
Orion Bus Industries
Dedicated CNG transit bus; max. 44 passengers; 30’ – 40’ length; low-floor; GVWR 42,540 lbs.; Detroit Diesel Corp. Series 50G/Cummins CG 280; range 350 miles
Certification: ULEV, CARB Low NOx

School Buses

All American RE
Blue Bird Corporation
Dedicated CNG school bus; max. 66/84 passengers; 33’ – 40’ length; John Deere 6081H 250 6-cylinder
Certification: CARB Low NOx

Refuse Trucks

LWT Refuse Truck
Crane Carrier Co.
Dedicated CNG low entry tilt (LWT) refuse truck; front loader; Cummins CG 275/280 hp or John Deere 6081H 280 hp 6-cylinder; single/ tandem rear axles; GVWR max. 60,000 lbs.; 70 GGE fuel capacity; 200 mile range
Certification: ULEV, CARB Low NOx

Street Sweepers

Crosswind J
Elgin Sweeper Co.
Dedicated CNG sweeper; recirculating air (vacuum) sweeper; Sterling SC 8000 chassis; Cummins 5.9L BG 195 6-cylinder; GVWR 33,000 lbs.; 8 cu. yd. hopper; 52 GGE fuel capacity
Certification: CARB Low NOx

Shuttles

Crusader
Champion Bus, Inc.
Dedicated CNG transit shuttle; max. 25 passengers; Ford E-450/Chevrolet Express cutaway chassis; 4-speed automatic; GM Vortec 5.4L/6.0L V8; GVWR 14,050 lbs.; 37 GGE fuel capacity; 300 mile range
Certification: ULEV, CARB Low NOx

Trolleys

TR 35 RE
Supreme/Specialty Vehicles Inc.
Dedicated CNG trolley; max. 35 passengers; rear engine; CAP/Cat 3126 dual-fuel; GVWR 31,000 lbs.; 300 mile range
Certification: CARB Low NOx

Miscellaneous Heavy-Duty Trucks

Isuzu NPR HD (chassis)
Baytech Corp.
Dedicated CNG heavy-duty truck; multiple applications, e.g., box trucks, beverage/package delivery, landscaping; 5.7/6.0L V8; 4-speed auto; GVWR 14,500 lbs.; 30 GGE fuel capacity
Certification: ULEV

LNG Vehicle Types

LNG vehicle types are currently limited to heavy-duty vehicles. Common examples of heavy-duty LNG vehicles include transit buses, refuse trucks and Class 8 urban delivery (regional heavy delivery) trucks.

The following types of heavy-duty LNG vehicles are currently available in California:

- Transit buses
- Refuse trucks
- Class 8 urban delivery (regional heavy delivery) trucks

Heavy-duty LNG vehicle models are currently available from a variety of truck manufacturers- and vehicle converters.

Examples of representative heavy-duty LNG vehicle types are shown below:

Transit Buses

NABI 35LFW
North American Bus Industries
Dedicated LNG transit bus; max. 30 passengers; 35’ low-floor; GVWR 41,150 lbs.; Detroit Diesel Series 50G/Cummins CG 275; 408 gal. LNG fuel tanks; 350 mile range
Certification: ULEV, CARB Low NOx

Refuse Trucks – Class 8 Urban Delivery

Century Class (chassis)
Freightliner LLC
Heavy-duty dual- fuel (LNG/diesel) Class 8 truck; Caterpillar C-12 410 hp 6-cylinder; GVWR 80,000 lbs.; 120 gal. LNG/60 gal diesel fuel tanks; 430 mile range
Certification: ULEV, CARB Low NOx

Appendix E

Energy Contents / Equivalencies for Natural Gas Fuels versus Electricity

1,000,000	Btu	In	1,000 ft^3	Natural gas / biomethane
3,412	Btu	In	1 kWh	Electricity
3.4 ft^3	Natural gas / biomethane	Same energy as	1 kWh	Electricity
120 ft^3	Natural gas / biomethane	Same energy as	1 gal	Gasoline
140 ft^3	Natural gas / biomethane	Same energy as	1 gal	Diesel
24 ft^3	Natural gas / biomethane	Same energy as	1 gal	CNG/CBM
84 ft^3	Natural gas / biomethane	Same energy as	1 gal	LNG/LBM
13,600 Btu	Natural gas / biomethane	Generates (at 25% efficiency)	1 kWh	Electricity
13.6 ft^3	Natural gas / biomethane	Generates (at 25% efficiency)	1 kWh	Electricity
10,400 Btu	Natural gas / biomethane	Generates (at 33% efficiency)	1 kWh	Electricity
10.4 ft^3	Natural gas / biomethane	Generates (at 33% efficiency)	1 kWh	Electricity
6,800 Btu	Natural gas / biomethane	Generates (at 50% efficiency)	1 kWh	Electricity
6.8 ft^3	Natural gas / biomethane	Generates (at 50% efficiency)	1 kWh	Electricity

Appendix F

Cost of Building Dairy Anaerobic Digesters per Kilowatt

Source Document	Digester Name	Date Built	Type	Cost to Build	Avg kW Generated	Cost/ Avg kW
Lusk	Not Ident	1979	Plug, Slurry	$510,000	182.6	$2,792
Nelson and Lamb	Haubenschild	2000	Plug	$355,000	98.0	$3,621
Moser and Mattocks	Haubenschild	1999	Plug	$329,851	85.0	$3,881
Lusk	Craven Dairy	1997	Plug	$247,450	78.3	$3,161
Moser and Mattocks	Craven Dairy	1996	Plug	$287,300	78.3	$3,670
Moser and Mattocks	AA Dairy	1997	Plug	$295,700	70.0	$4,224
Lusk	Fairgrove Farms	1981	Plug	$150,000	60.2	$2,491
Mattocks	AA Dairy	1998	Plug	$280,000	57.1	$4,906
Mattocks	Haubenschild	1999	Plug	$290,000	57.1	$5,081
Lusk	Foster Brothers	1982	Plug	$300,000	54.8	$5,475
Lusk	Cushman Dairy	1997	Comp Mix	$450,000	52.8	$8,523
Lusk	AA Dairy	1998	Plug	$343,300	50.5	$6,796
Lusk	Cooperstown	1985	Comp Mix	$500,000	37.1	$13,477
Lusk	Langerwerf	1982	Plug	$200,000	34.2	$5,840
Lusk	Kirk Carrell Dairy	1998	Plug	$100,000	30.0	$3,337
Lusk	Oregon Dairy	1983	Slurry	$120,000	25.7	$4,672
Moser and Mattocks	Cal Poly	1999	Lagoon	$230,000	19.4	$11,852
Lusk	Agway	1981	Slurry	$175,000	16.8	$10,393
Average dairy digesters over 50 kW						**$4,552**

Source: Lusk, 1998, Nelson and Lamb, 2000, Moser and Mattocks, 2000, Mattocks, 2000.

G. Linking Potential Biomethane Production with Possible Off-Farm Markets in California's Central Valley: Geographic Case Studies

The following analysis focuses on compressed biomethane (CBM) as a substitute for compressed natural gas (CNG) in the transportation fuel market.

The analysis relies on the use of various data and geographic information system (GIS) maps to match areas with potentially high and sustainable biomethane production to local points of distribution for CNG as a transportation fuel. Additionally, the analysis includes three case studies of sites that may prove to be optimal for further research into siting a pilot/demonstration project. These case studies include the criteria and characteristics that identify them as potential locations for future projects or further studies.

The case studies examine only those areas with high production potential. They are not intended as comprehensive feasibility studies. Specifically, these case-studies do not explore the following:

- Financial costs to implement a pilot project
- Actual market demand for biomethane
- Opportunity costs for CNG users
- Transaction costs associated with the necessary plant and product permitting, product liability, establishing "rights of way," and determining market price points
- Political potential for support of renewable methane production from dairies at the local, state, and federal level

Selection Criteria for Regional Focus

Three broad criteria were used to select a geographic region for further analysis:

- High concentration of dairies
- Regional demand for CNG as a transportation fuel
- Potential impact on local environmental quality

As discussed below, the San Joaquin Valley fit all three criteria.

Concentration of Dairies

According to 2002 California Department of Food and Agriculture data (CDFA, 2004a), farmers in the state of California produced 35,065 million pounds of milk. Within California, 8 of the top 10 milk producing counties are located in the San Joaquin Valle (Table G-1). The other two counties are San Bernardino and Riverside, both in the Inland Empire.

Table G-1 Top Ten California Milk-Producing Counties

County	Thousands of Pounds of Milk Produced in 2002		
	Grade A	Grade B	Total
Tulare	8,928,146	27,204	8,955,350
Merced	4,729,013	55,209	4,784,222
Stanislaus	3,544,088	47,203	3,591,291
San Bernardino	3,319,084	9,547	3,328,631
Kings	2,819,534	6,607	2,826,141
San Joaquin	2,141,645	8,348	2,149,993
Riverside	2,047,366	1,835	2,049,201
Fresno	1,842,574	2,200	1,844,774
Kern	1,754,901	2,261	1,757,162
Madera	1,007,308	7,807	1,015,115
All other California counties	2,381,394	164,386	2,545,780
Total	34,515,053	332,607	34,847,660

Because the concentration of dairies plays a critical role in the analysis and case-studies, a calculation was made of dairy milk production as a function of the size of each of the top 10 milk-producing counties (Table G-2).

Table G-2 Amount of Milk Produced per Square Mile in California's Top Ten Milk-Producing Counties

County	Grade A	Grade B	Total	Square Miles	Pounds Milk / Square Mile
Tulare	8,928,146	27,204	8,955,350	4,884	1,834
Merced	4,729,013	55,209	4,784,222	2,008	2,383
Stanislaus	3,544,088	47,203	3,591,291	1,521	2,361
San Bernardino	3,319,084	9,547	3,328,631	20,164	165
Kings	2,819,534	6,607	2,826,141	1,436	1,968
San Joaquin	2,141,645	8,348	2,149,993	1,436	1,497
Riverside	2,047,366	1,835	2,049,201	7,243	283
Fresno	1,842,574	2,200	1,844,774	5,998	308
Kern	1,754,901	2,261	1,757,162	8,170	215
Madera	1,007,308	7,807	1,015,115	2,147	473
All other California counties	2,381,394	164,386	2,545,780	---	---
Total	34,515,053	332,607	34,847,660	---	---

While instructive, the numbers in Table G-2 can be deceptive. Milk production is highly concentrated in both San Bernardino and Riverside counties. However, the concentration of dairies per square mile is lower because these are two of the largest counties in the United States.

When viewed as a group, the top seven counties (in terms pounds of milk produced per square mile) form a contiguous area much larger than the two Inland Empire counties combined, despite their size.

As shown in Table G-2, the seven counties with the highest concentration of milk production per square mile are:

1. Tulare
2. Merced
3. Stanislaus
4. Kings
5. San Joaquin
6. Fresno
7. Madera

These seven counties in the San Joaquin Valley provide 72% of all the milk production in California. Together, they represent the densest concentration of milk production anywhere in the USA, and possibly, in the world. The characteristics of the dairies in some parts of the San Joaquin Valley would appear to support concentrating on the region. Also, the dairy industry is still growing in the Central Valley, while it is a mature industry and reportedly on the decline in both San Bernardino and Riverside County (CDFA, 2004b).

Because future pilot projects may rely on multiple variables (e.g., access to active landfills, wastewater treatment facilities, etc.) for selection of a project site, the ability to focus on one large, contiguous area that included several different county governments, with different levels of infrastructure investment, appeared to be beneficial.

Regional Demand for Compressed Natural Gas as a Transportation Fuel

According the San Joaquin Air Pollution Control District (District), the region is home to over 1,200 CNG vehicles. That total is equally divided between light-duty and heavy-duty vehicles, at roughly 600 vehicles each. However, we believe these numbers to be low, as the data only reflects the vehicles within the membership of the San Joaquin Clean City Coalition as of the end of 2003. The District also believes that there are 61 public and private CNG fueling stations within the region. However, the source of this data could not be produced when requested of the San Joaquin Valley Clean City Coalition. Regardless, accurate data from both the U.S. Department of Energy and WestStart-CALSTART was found on the number of known stations located within the San Joaquin Valley.

According to data compiled from the WestStart-CALSTART web site <http://www.weststart.org>, the San Joaquin Valley Clean Cities web site <http://www.valleycleancities.org/>, and the US DOE Alternative Fuels Data Center, the San Joaquin Valley has 23 verifiable CNG stations as opposed to 20 CNG stations in the Inland Empire counties.

Although Riverside County has 14 CNG fueling stations, which is the greatest concentration of CNG fueling stations of any 10 top milk producing counties in the state, on a regional basis there are a greater number of stations in the San Joaquin Valley. In terms of conducting a geographic analysis, the San Joaquin Valley appeared to provide more options both in terms of linking demand with supply, and in linking potential production facilities both with the dairies and with the market for CNG as transportation fuel.

Summary of Reasons for Selecting San Joaquin Valley as Geographic Focus

Seven of the eight San Joaquin Valley counties (Tulare, Merced, Stanislaus, Kings, San Joaquin, Fresno, and Madera Counties) were selected to be the focus of this GIS analysis for three complementary reasons:

- High concentration of dairies
- Substantive and dispersed demand for CNG as a transportation fuel
- Dairy's relative impact on local environmental quality

Data Sources

To conduct this initial analysis, we attempted to gather data on four different variables:

- Dairies
- CNG demand
- Landfills (both active and collecting methane) and wastewater treatment plants (collecting methane)
- Local businesses with high CNG demand

Dairies

The data we wanted to acquire about the dairies in the seven counties of the San Joaquin Valley included geographic location and herd size. This data was obtained from three sources. The data for Fresno, Kings, Madera, and Tulare Counties was obtained from Kerry Elliot of the Regional Water Quality Control Board Region 5, Fresno office. The data for Merced and Stanislaus counties was obtained from Polly Lowry from the Regional Water Quality Control Board Region 5, Rancho Cordova office. Data for San Joaquin County and some additional data for Merced County were obtained from Jess Sitre of the Merced County Dairy Program, in Merced. (Jess Sitre provided a file with dairy locations in Merced County, but the file did not contain the number of cows per farm.)

Except for Merced County, the data seemed to be complete in terms of location and estimates of herd size. For the latter, we used the number of milking cows at each dairy. Many dairy farms also have other non-milking producing cattle on-site, but these animals are generally not fed in the "feed lanes" that are flushed to remove manure. As a result, their waste product (manure) is generally unavailable for CNG production. See Annex G1 for additional information regarding the characteristics of the dairy industry in the San Joaquin Valley.

Demand for Compressed Natural Gas

Demand for CNG as a transportation fuel is rising in California. The California Energy Commission (CEC) projects that California's annual demand for CNG as a transportation fuel will rise 46 million to 150 million therms by 2020 (CEC, 2001). In terms of gasoline gallon equivalents, it was estimated that in 2002, California used between 59 million to 67 million "gallons" of CNG (CEC, 2003). Most of this CNG (70% to 80%) was consumed by medium- to heavy-duty vehicles of which there are 4,350 in the state (CEC, 2003). An estimated 607 such vehicles are operating in the San Joaquin Valley (Urata, 2003). This amounts to 14% of the state's medium- to heavy-duty CNG vehicle population. As a relative comparison, the population of the region is just under 12% of California total population.

Regional data concerning the demand for CNG as a transportation fuel and its location within the Central Valley could not be found. As a proxy for establishing total demand and its location, we selected known CNG fueling stations. This data was obtained from three sources:

- A report on alternative fuel vehicles by Linda Urata of the San Joaquin Valley Clean Cities Coalition (prepared for the San Joaquin Valley Pollution Control District in 2003)
- WestStart-CALSTART Clean Car Maps (2004)
- DOE "Clean Cities" web site (2004)

The last two sources are both interactive databases found on the web. The Clean Car Maps database from WestStart-CALSTART was browsed for all seven counties of interest. The Alternative Fuels Center database was browsed using a 35-mile radius for all major metropolitan centers in the seven counties. Most CNG stations were identified in all three sources. The Urata report claimed upwards of 60 CNG fueling stations in the region. However, detailed locations of only 21 of the stations were provided. Upon further investigation it was determined that most of the CNG sites that could not be located were simply private holding facilities for small fleets that were serviced by CNG deliveries via truck.

For future efforts that attempt to further assess the feasibility of biomethane projects, we recommend a more comprehensive survey of CNG fueling stations be conducted. There are two reasons for this. First, the data from web sources does not appear to be updated often enough to be comprehensive. Additionally, each web-based database contained a different number of total stations. Also, the data from Clean Cities Coalition needs to be more detailed in terms of both location and the annual equivalent (in millions of gallons) of CNG dispensed by each station.

Landfills and Wastewater Treatment Facilities

To build a system capable of economically converting dairy methane biogas into transportation fuel, other research indicated the necessity of using large waste-handling facilities as aggregators and/or processors of the fuel. To satisfy this requirement, data was collected on landfills and wastewater treatment facilities in the seven-county area that currently collect and/or process methane as a by-product of their operations. This data was obtained from the California Energy Commission's "List of Waste to Energy Power Plants in California" (<http://www.energy.ca.gov/development/biomass/index.html>).

Local Businesses with High Demand for Compressed Natural Gas

Prior to the research team's trip to Europe (see main report), data was collected on the natural gas demand of local businesses within the San Joaquin Valley from Dun & Bradstreet (<http://www.zapdata.com>). To determine natural gas usage, the Dun &Bradstreet industry information was cross-referenced by SIC code to the average energy consumption, which was provided by the DOE (Unruh, 2004).

Analysis of the Accuracy of Data Collected

Prior to conducting our analysis, we sought to determine the accuracy of two key variables: the number of cows per dairy and data point location. These data points included not only each dairy but also the CNG stations, wastewater treatment facilities, landfills, and business utilizing CNG. In terms of the number of cows per dairy, the only record of the number of cows per county and the number of dairies per county available from California State government resources was reported data from 1998 and 1999 (CEC, 2004). As mentioned previously, these numbers represent the number of milking cows, not total herd size.

The data is up to five years old and the CDFA (2004b) reports significant changes in the number of dairy farms each year. However, we believe the 1999 data can be used to determine the reasonableness of the data that we collected. The percentage differences between this 1999 data and the data we used are provided in Annex G2.

Annex G2 shows that the number of cows per farm in Madera has significantly increased while the number of dairy farms has remained consistent. Tulare County experienced a small increase in the number of farms and the number of cows. San Joaquin and Stanislaus Counties both experienced a decrease in the number of farms and in the number of cows. The one county where the data we received does not appear to be complete is Merced County. However, we feel we have compensated for this. Refer to Annex G2 for a fuller discussion.

We used several sources to determine the accuracy of the geocoded longitude and latitude location of facilities. Please see Annex G2 for a full description.

Determination of Viable Project Locations

The methodology we used to determine the best locations for biomethane projects in the seven-county area is described below.

Initial Criteria: Nearby Fueling Stations

Research conducted in Europe determined that one of the more ideal off-farm uses of biomethane is as renewable natural gas for transportation uses. Based on this assumption, we sought data on the location of public and private CNG distribution stations in the San Joaquin Valley. An ideal scenario for a biomethane project would be a situation in which locally produced biomethane would be blended with CNG at nearby filling stations and utilized by CNG vehicle drivers.

First, even before we conducted a GIS analysis, we identified an initial 400-square-mile area surrounding each known CNG station location. The 400-square-mile area was centered at the CNG station and extended 10 miles in each direction: to the north, south, east, and west (Figure G-1).

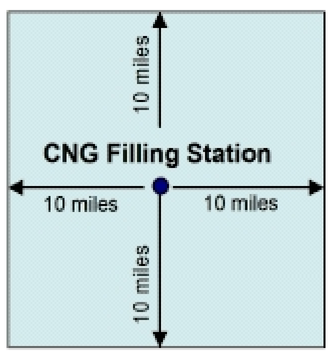


Figure G-1 Identification of 400-Square-Mile Area around CNG Filling Station

All of the dairy farms, wastewater treatment plants, landfills, and other CNG stations located within this initial area were then identified (through an analysis of their geocodes), relative to the main CNG station. The locations were ranked based on the purported number dairy cows nearby.

Initial Site Rankings: Proximity to Dairies

Table G-3 provides a list of the sites ranked according to their proximity to dairies. The table does not include CNG fueling locations that had no cows in the surrounding 400-square-mile area. (A complete list of all CNG stations that were included in this analysis is included in Annex G3).

The initial analysis identified three locations with more than 100,000 nearby cows. Detailed maps were then made of these top three sites (Tulare FleetStar, FleetStar – SoCal Gas, and Kings County Yard/PFC) to enable further study. Additionally, a detailed map was also made of the fourth-ranked site (W.H. Breshear's FleetStar) for two reasons. First, the number of dairies relative to the number of overall cattle could indicate a very concentrated local industry. Second, the local concentration of businesses using a substantial amount of natural gas indicated other potential markets for the CBM outside of the transportation sector. Due to limited resources, we did not further investigate the remaining 14 locations shown in Table G-3. See Annex G4 for site descriptions of the sites ranked 4 through 8.

Table G-3 Initial Ranking of CNG Filling Stations Based on Number of Cows in Surrounding Area

Rank	CNG Location	Cows	Dairies	Wastewater Treatment	Landfill	Other CNG Stations
1	City of Tulare – FleetStar [a]	269,897	235	3	6	0
2	FleetStar - SoCal Gas [a]	132,291	129	3	5	0
3	Kings County Yard/PFC [a]	129,766	150	0	2	1
4	W.H. Breshear's – FleetStar [a]	77,212	160	0	10	0
5	PG&E Merced Service Center [a]	*68,600*	92	0	3	0
6	Lemoore NAS	61,979	92	0	2	1
7	Kings Canyon Unified Sch. Dist.[a]	40,048	30	0	0	0
8	Tesei Petroleum [a]	37,488	30	0	2	0
9	City of Fresno Service Center	17,924	27	1	4	4
10	Visa Petroleum	14,424	23	1	7	4
11	Pinnacle CNG/UPS	12,324	21	1	7	4
12	San Joaquin County	10,895	29	3	9	1
13	PG&E Stockton Service Center	9,395	17	3	10	1
14	CSU Fresno	7,273	11	1	7	4
15	E.F. Kludt and Sons	7,245	12	0	1	0
16	Clovis Unified School District	4,840	6	0	5	4
17	Gibbs Auto Fuel Station	4,475	7	0	1	1
18	City of Delano	2,050	2	0	2	0

[a] These CNG stations are described in detail in this study.

GIS Analysis: More In-depth Rankings

The initial analysis helped guide our selection of CNG sites for further analysis using GIS, a method that can provide more complete results. Our initial analysis examined only the total numbers of cows and potential facilities where biogas might be collected and upgraded; the GIS analysis would provide the additional detail needed for this study.

The upgrading of dairy biogas into a transportation fuel (biomethane) is capital intensive. In most cases, installation of an upgrading plant would be too expensive and complex for a single dairy —or even a group of dairies—to install and operate. Through GIS analysis, the location of existing wastewater treatment facilities and landfills that were already processing methane could be identified and cross-checked against areas with high concentrations of dairy cows.

We began the GIS analysis by working backwards from the "point of demand" (i.e., the CNG station). First, we sought to determine first the number of cows and infrastructure within a 9-mile radius of the CNG station. Next, we sought to determine the number of cows within an approximate 3-mile radius of any identified infrastructure.

Table G-4 Ranking of Wastewater Treatment Facilities and Landfills in Proximity to Dairies

Rank	Facility Name (Wastewater Treatment Plant or Landfill)	Number and Potential Production of Wastewater Treatment Facilities, Landfills, and Nearby Dairies (9-mile radius)			
		Infrastructure	Dairies	Cows	Annual Biomethane Potential a (million ft^3)
City of Tulare		5	98	124,209	1,360
1	New Era #2		25	41,867	458
2	New Era #1		33	38,670	423
3	Soil Food		30	37,566	411
4	Woodville Disposal		21	29,971	328
8	Tulare County		18	12,685	139
SoCal Gas, Visalia		5	42	41,446	454
5	Wood Industries		21	23,715	260
6	Tulare County		29	16, 835	184
7	Visalia Disposal		9	13,681	150
	Other 2 are two small				0
Kings County Yard/PFC		2	73	59,930	656
9	KWRA Materials & Composting		17	11,299	124
10	Hanford City Wastewater Treatment		11	7,329	80
W.H. Breshear's of Modesto (Incorporates 4 other facilities)		5	77	35,565	389
11	Central Valley		14	4,870	53
12	Bonzi		13	4,305	47
13	City of Modesto		7	3,930	43

[a] Biomethane potential assumes 30 ft^3 biomethane per cow per day

While the selection of the 9-mile radius was relatively arbitrary—an attempt on our part to simply hold down the transportation and delivery costs of the refined and potentially compressed biomethane—the 3-mile radius around the infrastructure was not. It was selected because of the high variable costs of moving manure to a centralized point and/or the high capital costs of permitting and installing piping to carry the raw biogas from on-farm anaerobic digesters to an aggregating facility.

Using only the top four CNG sites identified in the initial analysis, we then ranked the surrounding infrastructure within the nine mile radius based on their potential annual biomethane production from dairies within three miles of them. The table below organizes these sites around the CNG stations they would serve and supplies each one with a corresponding rank. Each of the four filling stations shows the potential volume of biomethane within a 9-mile radius; landfills and wastewater treatment plants within the 9-mile radius of the filling station are listed below each filling station. Next to each landfill or treatment plan is the potential volume of biomethane within a 3-mile radius of that facility. If the facility is on the edge of the original 9-mile radius, then its 3-mile radius may incorporate a dairy that is outside the filling station's 9-mile radius.

What we found was that the most promising pilot/demonstration project sites would almost all be centered on the CNG station in the City of Tulare. Table G-5 compares the results of the initial to those of the GIS survey, with the given parameters.

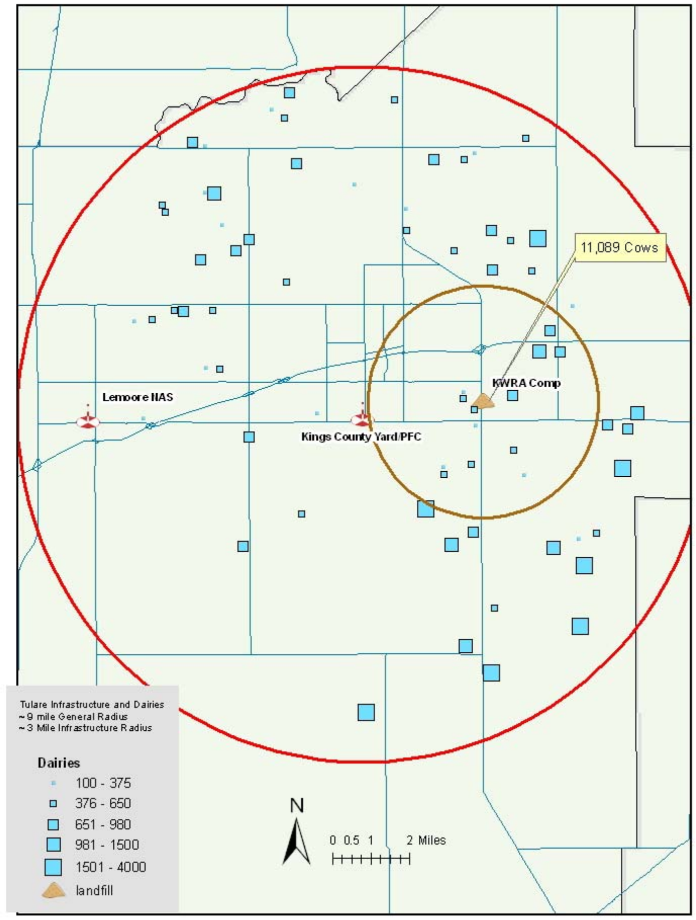
Table G-5 Comparison of Sites Based on Initial and GIS Rankings

	City of Tulare		**SoCalGas, Visalia**		**Kings County Yard**		**W.H. Breshear of Modesto**	
	400 mi^2	**9-mi radius**	**400 mi^2**	**9-mi radius**	**400 mi^2**	**9-mi radius**	**400 mi^2**	**9-mi radius**
Cows	269,897	124,209	132,291	41,446	129,766	59,930	77,212	35,565
Dairies	235	98	129	42	150	73	160	77
Annual Biomethane Potential (million ft3)	2,945	1,360	1,448	453	1,421	656	845	389
Infrastructure and other CNG Facilities	9	5	8	5	3	2	10	5

What seemed like promising sites after the initial analysis looked less promising on the basis of the GIS analysis. For example, the Kings County Yard CNG Station initially seemed appealing as its overlap with the Lemoore NAS indicated that these two stations might be able to somehow work in conjunction (e.g., sharing costs for biomethane aggregation and processing equipment). Additionally, under EPAct, the federal facility is under a mandate to use alternative fuels for up to 20% of their fleet vehicles. Based on the GIS analysis, however, this promising location would most likely not make a good spot for a pilot/demonstration project due to the low concentration of nearby dairies around local infrastructure (see Map 1).

Map 1

Proximity Analysis of Dairies to Infrastructure
- Kings County Yard, Hanford -



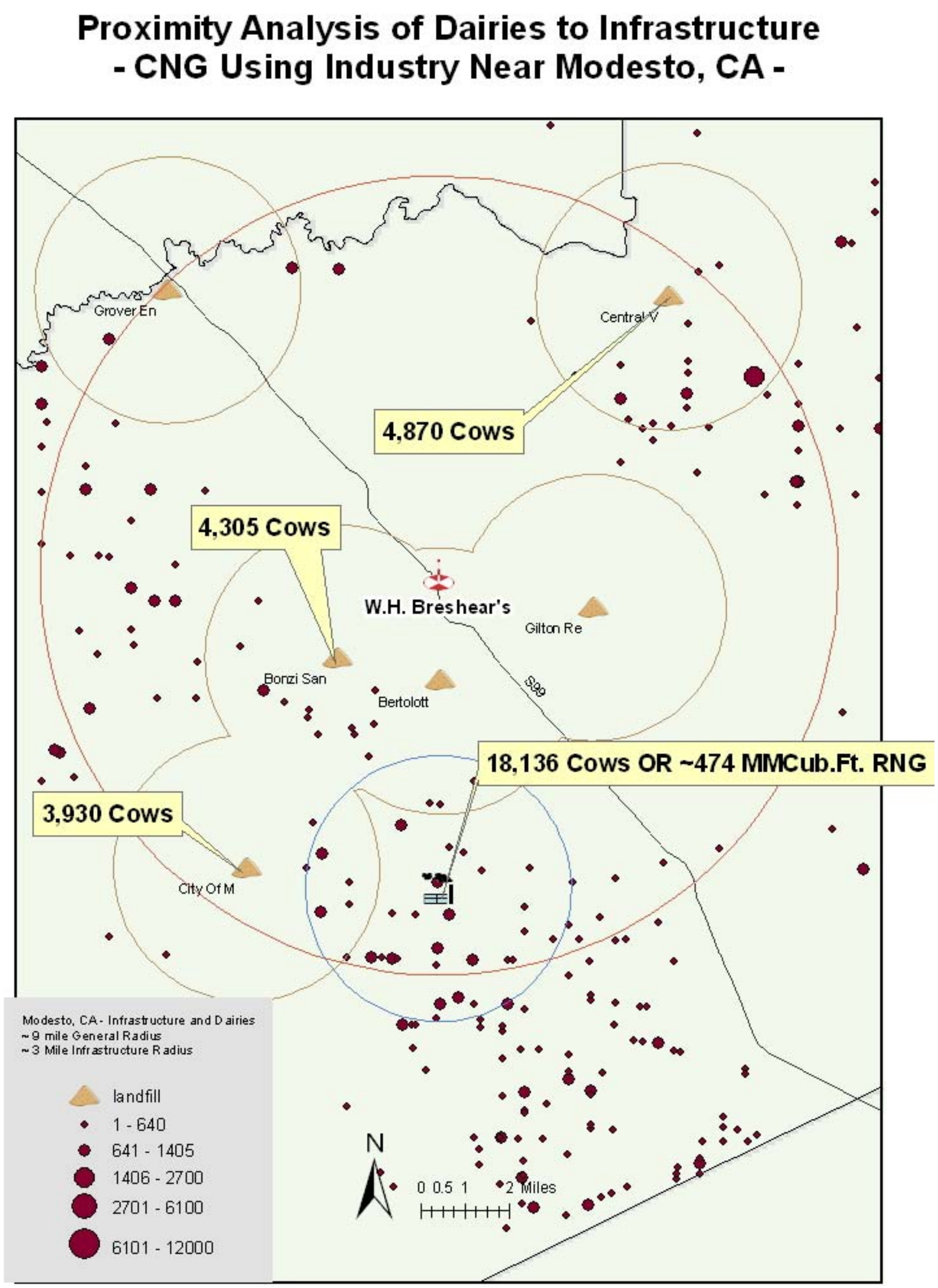
Additional Data

In addition to the data collected on dairies, CNG facilities, wastewater treatment plants, and landfills, data was also collected on local businesses with high natural gas usage. This data was gathered initially as it was unknown as to what type of final biomethane “end-use” would be selected from the research done in Europe. We hoped that understanding the locations and demands of businesses with high demand for natural gas a potential might provide an insight into potential markets for dairy biomethane production.

Ultimately, it was determined that biomethane as a transportation fuel made the most economic sense for future pilot projects. Consequently, the number of potential biomethane end-use industries was not used to rank the locations. However, this information was included in the discussion of the sites because such buyers could provide an alternate market for excess biomethane.

It is interesting to note that in the analysis of Site #4, W.H. Breshear's of Modesto, the most compelling case for using biomethane involves a business with a large CNG demand. In fact this business is surrounded by more dairies than any landfill or wastewater treatment facility combined (see Map 2 below).

Map 2



Description of Sites

The following four case studies of the highest ranked sites (see Table 3) use raw GIS data to conduct cursory analyses of the potential for future research pilot/demonstration projects using biomethane as a transportation fuel. With the exception of Site #4, we chose 100,000 dairy cows as an arbitrary “cut-off” point for in-depth GIS analysis. For information on other top-ranked sites, please refer to Annex G4, which contains much of the same ranking information without accompanying maps.

Site #1: City of Tulare, FleetStar

The number 1 ranked location is the City of Tulare FleetStar station. The exact location is:

3989 S K Street
Tulare, CA 93274

This CNG station allows public access with restrictions. In 2003, the station sold 84,000 gasoline gallon equivalents of CNG (Al Miller, City of Tulare, personal communication).

This facility is located at the southern spur of the city of Tulare, Tulare County, in the Southern California Edison service territory (this service area is included as Annex G5). The facility is within a half mile of Highway 99. Of the 235 dairies in the area, 232 are located in Tulare County and 3 are located in Kings County. According to the 2000 US Census data (2002), the City of Tulare has a population of 43, 994. The breakdown on “customers” for this station was 18 heavy-duty CNG vehicles and 42 light-duty CNG vehicles. The station is unique in that it receives LNG and converts it to CNG as needed.

The wastewater treatment plants and landfills located in the area of initial analysis are listed below. The following map (Map 3) details a smaller area that includes 9 miles around the CNG Station; only five wastewater treatment plants and landfills are included in this smaller zone. For more information about these facilities, see annexes G6 and G7.

1. City Of Tulare
   1875 South West Street
   Tulare, CA
2. Royal Farms #1 - #2
   Tulare, CA 93274
3. Tulare County Landfill and Recycling Complex
   26951 Road 140
   Visalia, CA 93292
4. New Era Farm Service #2
   Jim Nance Dairy
   6440 Ave 160
   Tulare, CA

5. New Era Farm Service #1
   Hoffman Dairy Ave 216 & Rd 140
   Tulare, CA

6. Tulare County Compost and Biomass
   24487 Road 140
   Tulare, CA

7. Soil Foods, Inc.
   20002 Road 140
   Tulare, CA

9. Woodville Disposal Site
   Rd 152 At Ave 198
   Tulare, CA

Three of the sites mentioned above—the City of Tulare, Royal Farms, and Tulare County—all currently generate electricity by burning methane produced by animal waste. The City of Tulare's plant is 0.41 MW, the Royal Farm is 0.18 MW and the Tulare County Landfill is 1.9 MW.

There are three businesses within the area of analysis that use large amounts of natural gas. Based on industrial sales and national average industry natural gas usage for these businesses, we estimate that these three locations would use a total of 129,564,000 kBtu/year.

The three businesses are:

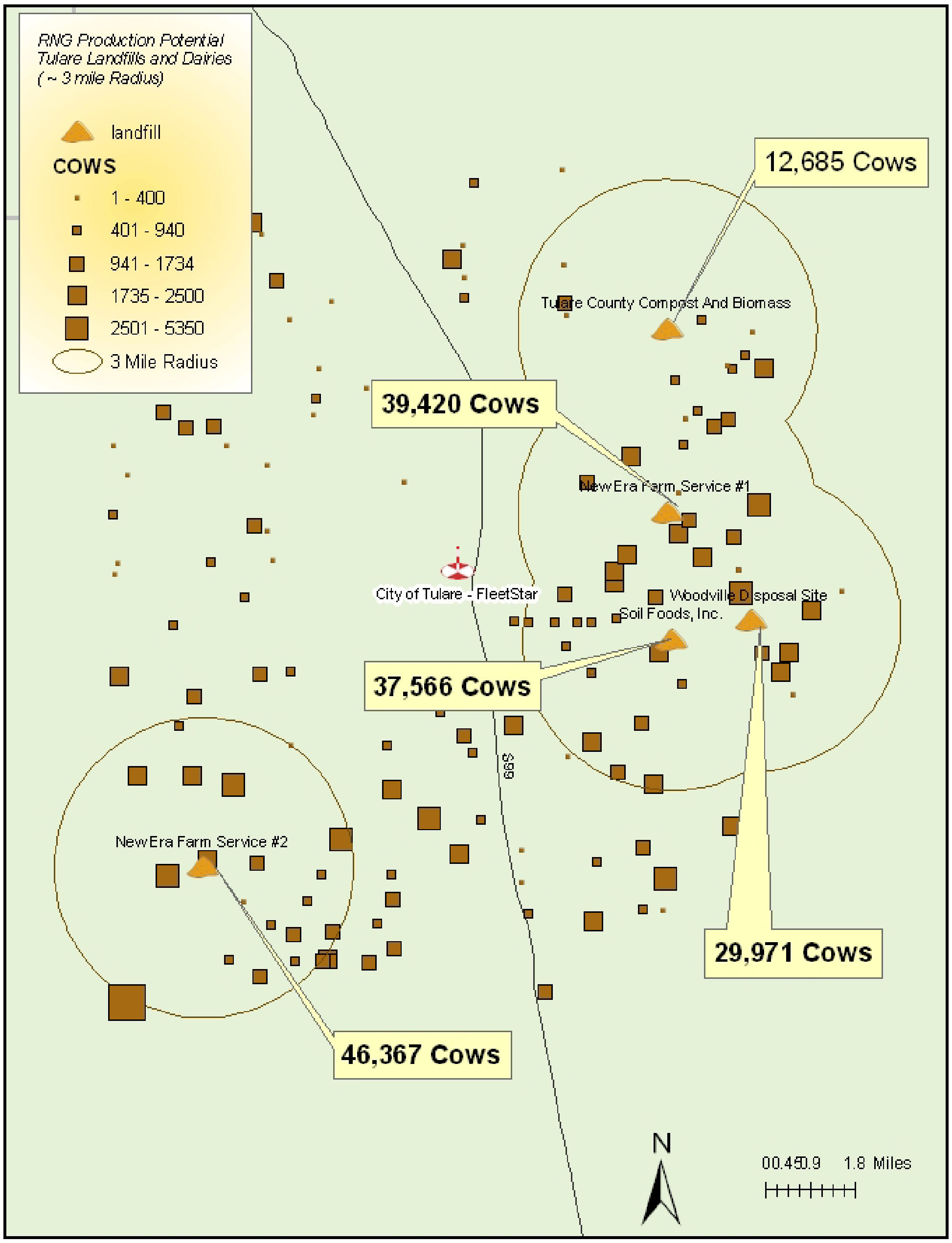
1. JIT Steel Inc
   2000 S O St
   Tulare, CA 93274
   Process sheet metal
   Estimated Natural Gas usage = 33,400,000 kBtu/year

2. Golden Valley Dairy Products
   1025 E Bardsley Ave
   Tulare, CA 93274
   Mfg cheese and whole dairy products
   Estimated Natural Gas usage = 45,124,000 kBtu/year

3. CP International
   800 E Paige Ave
   Tulare, CA 93274
   Mozzarella cheese & whey manufacturing
   Estimated Natural Gas usage = 51,040,000 kBtu/year

Map 3

Proximity Analysis of Dairies to Infrastructure - City of Tulare CNG Station -



Site #2: Visalia SoCal Gas, FleetStar

The second ranked location is the Visalia's SoCal Gas-FleetStar. The exact location is:

FleetStar-SoCal Gas
320 N Tipton Street
Visalia, CA 93292

This CNG location distributed 63,000 gasoline gallon equivalents of CNG in 2003.

This facility is located on the western end of the city of Visalia, Tulare County, and is approximately 18 miles NNW of Site #1. The 2000 US Census (2002) states that the city of Visalia had a population of 91,565. The CNG facility is within two miles of Highway 198, which provides easy access to Highway 99. The CNG station is in Southern California Edison's service territory (Annex G5).

Of the 129 dairies in the surrounding area, 127 are located in Tulare County and 2 are located in Fresno County. Much of the area surrounding this site and Site #1 overlap, including 72 dairies, 3 of the infrastructure facilities identified previously, and 2 of the 3 major industrial users of CNG identified. Please refer to the accompanying map (Map 4) for more details.

The wastewater treatment plants and landfills located in the area of initial analysis are listed below. The following map details a smaller area of 9 miles around the CNG Station and includes only three of these facilities. For more information about all the facilities, see annexes G6 and G7. Again, the first three landfill locations are identical to locations identified in Site #1 but are not shown on the following map as they are outside of the nine mile radius of analysis.

1. Tulare County Recycling Complex
   26951 Road 140
   Visalia, CA

2. Tulare County Compost and Biomass
   24487 Road 140
   Tulare, CA

3. Woodville Disposal Site
   Rd 152 at Ave 198
   Tulare, CA

4. Sunset Material Recovery Facility
   1707 East Goshen Road
   Visalia, CA

5. Visalia Disposal Site
   Rd 80 at Ave 332
   Visalia, CA

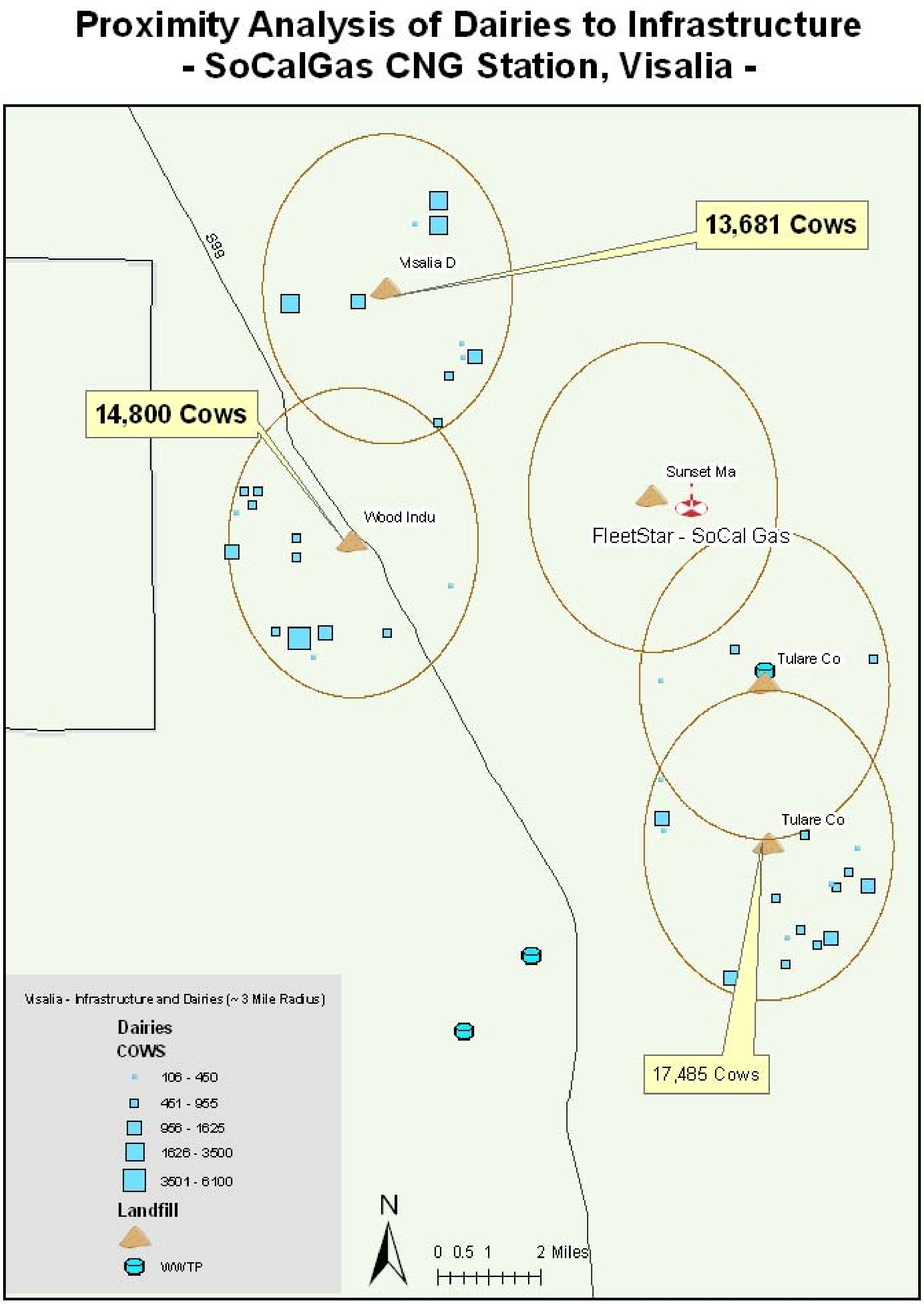
Two of the three businesses listed below were identified previously and are within the initial analysis area of Tulare's SoCal Gas CNG station. Based on the industries' sales and national average industry natural gas usage, it is estimated that these three locations would use a total of 124,924,000 kBtu/year. Please refer to the following map for greater details. The three businesses are:

1. JIT Steel Inc
   2000 S O St
   Tulare, CA 93274
   Process sheet metal
   Estimated Natural Gas usage = 33,400,000 kBtu/year

2. Golden Valley Dairy Products
   1025 E Bardsley Ave
   Tulare, CA 93274
   Mfg cheese and whole dairy products
   Estimated Natural Gas usage = 45,124,000 kBtu/year

3. California Pretzel Co Inc
   7607 W Goshen Ave
   Visalia, CA 93278
   Pretzel and cookie production
   Estimated Natural Gas usage = 46,400,000 kBtu/year

Map 4


Proximity Analysis of Dairies to Infrastructure
- SoCalGas CNG Station, Visalia -
13,681 Cows
Visalia D
599
14,800 Cows
Wood Indu
Sunset Ma
FleetStar - SoCal Gas
Tulare Co
Tulare Co
17,485 Cows
Visalia - Infrastructure and Dairies (~ 3 Mile Radius)
Dairies
COWS
106 - 450
451 - 955
956 - 1625
1626 - 3500
3501 - 6100
Landfill
WWTP
N
0 0.5 1 2 Miles

Site #3: Kings County Yard/PFC

The third ranked location is the Visalia SoCal Gas-FleetStar. The exact location is:

Kings County Yard/PFC
11827 S 11th Ave
Hanford, CA 93230

This CNG location allows public access with restrictions. In 2003, the station sold 45,000 gasoline gallon equivalents of CNG.

This facility is located in the southern half of the city of Hanford, in Kings County. According to the 2000 US Census (2002) the city of Hanford had a population of 41,685. The CNG station is also within 2 miles of Highway 198, providing easy access to Highway 99. Of the 150 dairies in the surrounding area, 116 are located in Kings County, 23 are located in Tulare County, and 11 are located in Fresno County. The CNG station is also in Southern California Edison's service territory (Annex G5).

Not surprisingly given the concentration of dairies in the region, the initial analysis of this site had a portion of the area surrounding this location overlapping with both Site #1 and Site #2. To be exact, there are 5 dairies that fall within the overlap with Site #1, and 24 dairies with Site #2. However, none the sites showed overlap under the more tightly focused GIS analysis.

Of the 30,000 gallon equivalents distributed by the Kings County CNG station, it was estimated that 33% was used by medium-to-heavy-duty vehicles.

Our analysis only indicated one wastewater treatment facility in the area of initial analysis surrounding this site and one landfill actively collecting and utilizing methane. The locations are:

1. KWRA Material Recovery and Composting Facility
   7803 Hanford-Armona Rd.
   Hanford, CA 93230

2. City of Hanford Waste Water Treatment Plant
   1055 Houston Ave.
   Hanford, CA 93230

As mentioned previously, there is another CNG filling station close by: the CNG station located near the Lemoore Naval Air Station (NAS). The Lemoore station is just 10 miles west of the Kings County CNG station. There are fewer than half the number of cows and dairies near the Lemoore location than there are near the Kings County CNG station. This is because of the significant size of the Lemoore NAS facility. The Lemoore NAS CNG station is a government site and there is no public access, however, federal facilities are under a mandate (EPAct) to use cleaner burning and/or renewable fuels in their fleet vehicles (up to 20%). Further investigation is necessary, but this site may provide an outlet for biomethane aggregated and refined at one of the two nearby infrastructure facilities.

Additionally, there are four businesses near the CNG station. Based on industrial sales and the national average natural gas usage for these industries, it is estimated that these four businesses would use a total of 342,930,000 kBtu/year. The four businesses, which represent a small additional potential demand, include the following:

1. Central Valley Meat Co Inc
   10431 8 3/4 Ave
   Hanford, CA 93230
   Meat Packing Plants
   Estimated Natural Gas usage = 52,896,000 kBtu/year

2. Mineral King Minerals Inc
   10585 Industrial Ave
   Hanford, CA 93230
   Nitrogenous Fertilizers
   Estimated Natural Gas usage = 51,487,500 kBtu/year

3. Moore Agricultural Products Co
   11521 Excelsior Ave
   Hanford, CA 93230
   Nitrogenous fertilizers
   Estimated Natural Gas usage = 188,318,023 kBtu/year

4. SK Foods
   1175 19th Ave
   Lemoore, CA 93245
   Canned Fruits and Specialties
   Estimated Natural Gas usage = 50,228,000 kBtu/year

Site #4

The fourth ranked location is W.H. Breshear's FleetStar, located at 428 7th Street, Modesto, California 95354. This CNG station will be shut down in December of 2004 due to the low volume of sales (personal conversation with FleetStar company representative).

This facility is located in the center of the City of Modesto in Stanislaus County. According to the US Census data for 2000 (2002), the city of Hanford had a population of 188,856. The facility is within a half mile of Highway 99. Of the 160 dairies in the surrounding area, 157 are located in Stanislaus County and 3 are located in San Joaquin County. Modesto has a history of using biomethane to fuel its fleet vehicles. However, the system was destroyed by a flood in the mid-1990s and was never repaired.

The dairies in this area are smaller than in the top three sites and thus it may take more work to coordinate biomethane production. Yet, there is a long history of dairies operating in this area. A combination of factors led us to believe that despite the higher number of dairies and smaller herd size, these dairies may be geographically concentrated that could compensate for such hurdles.

There is only one major wastewater treatment plant in the area. This facility is owned by the City of Modesto and does not currently collect methane for any purposes.

There are 10 landfills listed in the area, but many of them overlap. In all, there are only 5 distinct sites. This still shows a number of potential collaborating partners that could provide biomethane aggregating and processing capabilities for the numerous dairies. The 8 landfills, listed below, are shown on the Map 2. For more information about the landfills see Annex G7.

1. Grover Environmental Products/Salida
   6131 Hammett Road
   Modesto, CA 95358

2. City Of Modesto Co-Compost Project
   7007 Jennings Road
   Modesto, CA 95358

3. Modesto Disposal Svc TS/Res Rec Fac
   2769 West Hatch Road
   Modesto, CA 95358

4. Bonzi Sanitary Landfill
   2650 West Hatch Road
   Modesto, CA 95358

5. Bertolotti Transfer & Recycling Center
   231 Flamingo Drive
   Modesto, CA 95358

6. Valley Wood Disposal
   1800 Reliance Street
   Modesto, CA 95358

7. Gilton Resource Recovery
   800 S. McClure Rd.
   Modesto, CA 95357

8. Central Valley Agricultural Grinding, Inc.
   5707 Langworth Road
   Modesto, CA 95357

Twelve businesses in the area use a substantial amount of natural gas. This Modesto site provides the largest number and volume of alternative uses for biomethane. Accordingly, it minimizes the market risks associated with dependency on a single CNG filling station.

1. Formulation Technology Inc
   571 Armstrong Way
   Oakdale, CA 95361
   Intravenous solutions
   Estimated Natural Gas usage = 109,153,500 kBtu/year

2. Valley Fresh Inc
   680 D St
   Turlock, CA 95380
   Poultry, processed: canned
   Estimated Natural Gas usage = 162,168,000 kBtu/year

3. Sensient Dehydrated Flavors
   151 S Walnut Rd
   Turlock, CA 95380
   Vegetables, dried or dehydrated (except freeze-dried)
   Estimated Natural Gas usage = 150,800,000 kBtu/year

4. Pacific Southwest Cont LLC
   4530 Leckron Rd
   Modesto, CA 95357
   Boxes, corrugated: made from purchased materials
   Estimated Natural Gas usage = 656,949,000 kBtu/year

5. Boyd Corporation
   600 S McClure Rd
   Modesto, CA 95357
   Hard rubber and molded rubber products
   Estimated Natural Gas usage = 41,750,000 kBtu/year

6. Signature Fruit Company LLC
   2260 Tenaya Dr
   Modesto, CA 95354
   Fruits: packaged in cans, jars, etc
   Estimated Natural Gas usage = 59,160,000 kBtu/year

7. John F. Turner and Company
   1911 Yosemite Blvd
   Modesto, CA 95354
   Stationery products
   Estimated Natural Gas usage = 108,962,500 kBtu/year

8. Triad Waste Management
   204 Kerr Ave
   Modesto, CA 95354
   Fertilizers, mixing only
   Estimated Natural Gas usage = 247,140,000 kBtu/year

9. Gallo Glass Company
   605 S Santa Cruz Ave
   Modesto, CA 95354
   Glass containers
   Estimated Natural Gas usage = 594,909,000 kBtu/year

10. E & J Gallo Winery
    600 Yosemite Blvd
    Modesto, CA 95354
    Wines
    Estimated Natural Gas usage = 497,756,000 kBtu/year

11. Stanislaus Distributing Co
    400 Hosmer Ave
    Modesto, CA 95351
    Carbonated beverages, nonalcoholic: pkged. in cans, bottles
    Estimated Natural Gas usage = 42,920,000 kBtu/year

12. Horizon Ag-Products Inc
    P.O. BOX 1888
    Modesto, CA 95353
    Soil conditioners
    Estimated Natural Gas usage = 67,963,500 kBtu/year

Conclusion and Further Study

Based on industrial sales and the national average natural gas usage for the represented industries, we estimate that the four locations investigated in this report would use more than 2.7 billion kBtu/year.

This GIS-based analysis was meant only to investigate the potential for more focused pilot/demonstration project in the future. The San Joaquin Valley was selected not only because it has a large and growing dairy industry, but also because the region and its inhabitants are disproportionately impacted by the dairy industry’s waste by-products. A similar analysis could be conducted for the dairy industry in the Inland Empire (Riverside and San Bernardino counties).

In terms of selecting optimal sites for future pilot/demonstration projects, we suggest the following steps:

1. *Investigate Tulare project site.* Based on all of the available data, the best project site would be near the City of Tulare CNG station. The concentration of dairies near existing infrastructure already collecting methane (in some form) makes the Tulare area a prime location for further analysis into a pilot/demonstration project.

2. *Improve data for future analysis.* Prior to launching a pilot/demonstration project, resources must be invested in generating or collecting better data. While sufficient for the purposes of this study, a more exhaustive survey accounting for the location and size of each dairy farm should be undertaken; this is especially needed for Merced County. Any such survey should also identify the type of dairy manure collection system in place at each of the targeted dairies. Estimated volumes of potential biomethane production rest on several broad assumptions about manure collection and handling; these assumptions should be checked prior to launching a pilot and/or demonstration project.

Additionally, data for both the wastewater treatment plants and landfills reflect only those sites known to be collecting and using methane. No steps were taken to determine if other types of sites not currently collecting and using methane would be willing to accept dairy waste into their operations. Locations of these other sites are known, but a decision was made not to include them in this preliminary analysis. A more comprehensive survey is needed to ascertain the best possible sites for aggregating and processing biomethane for a pilot study.

Also, our estimate of the potential industrial use of natural gas was based solely on sales of the firm and the industry average use of natural gas based on sales. The natural gas usage of an individual business may vary significantly from the industry average. If it is determined that industrial biomethane demand is a viable market, these businesses should be contacted and their actual natural gas usage verified prior to final site selection.

3. *Explore utilization of other waste streams.* Provided that potential aggregating sites are willing to work with multiple feedstocks (other types of waste materials), it would be beneficial to determine if any other potential sources of biogas exist in the area of a future pilot/demonstration project. These sources could include non-dairy concentrated animal feeding operations (CAFO), by-products from local food-processing facilities, cull and surplus produce, yellow grease from restaurant operations, and potentially, waste from slaughterhouses. Combining of these waste streams into a single biomethane operation may create technical and permitting hurdles (especially from a transporting perspective), it can also increase the quantity of biomethane produced and improve a region’s ability to sustainably handle its waste.

4. *Refining facility location.* Much of our analysis worked “backward” from the point of final distribution, the CNG station itself. All CNG stations and most aggregating and refining infrastructure are located in or near cities; however, it may be better to locate a biomethane refining facility farther out in the rural areas. A few miles difference in the final site location can have a significant impact on the number of nearby dairies The GIS analysis could be applied to more rural sites to identify locations proximate to larger concentrations of dairies.

   Although it would appear that demand for CNG as a transportation fuel is growing more robustly in the southern part of the San Joaquin Valley, CNG fueling station locations in the region are in a state of flux. During the course of this study, one of the top four potential locations for a pilot project moved and another was closed. This fact stress the importance of conducting a more thorough survey of local CNG vehicle operators and CNG fuel distributors prior choosing any potential pilot project site.

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Annex G1: Characteristics of Dairy Industry in the San Joaquin Valley

There are 1,159 dairy farms in the seven counties included in this report. Dairy farms that have closed down and no longer have milking cows and dairy farms that are just starting and do not yet have milking cows are not included in the dairy farm count. Additionally, there were ten farms reported that had 6,825 cows between them for which we were not given the longitude and latitude coordinates. These records represent less than 1% of the total dairy farms and less than 1% of the total number of cows. Without the longitude and latitude coordinates the records could not be included in the GIS analysis.

The average number of cows per farm was 821, the median was 550 and the mode was 400. Only milking cows were included in the number of cows on the farm. Non-milking cows are not included in any aspect of this analysis. The smallest number of cows per farm was one and the largest number of cows per farm was 12,000. The following table shows the distribution of dairy farms based on the number of cows per farm for all seven counties.

Distribution of Farms based on the Cows per Farm

Cows per Farm	Number of Farms	Percent
1 - 500	543	46.9%
501 - 1000	341	29.4%
1001 - 2000	190	16.4%
2001 - 4000	70	6.0%
More than 4000	15	1.3%
	1159	100.0%

The variance in the number of milking cows per farm between the seven counties is statistically significant. Stanislaus, Merced and San Joaquin counties all average less than 550 cows per farm. Kings, Tulare, and Madera counties all average more than 1,000 cows per farm. The probability of this variance in size happening by chance is less than 1 in million. The causes for the variances in the average number of cow per farm by county were not investigated because that research is beyond the scope of this report.

Average Cows per Dairy by County

County	Number of Dairy Farms	Total Cows	Average Cows / Farm
Stanislaus	271	130,494	481.5
Merced	161	86,420	536.8
San Joaquin	134	73,153	545.9
Fresno	102	90,220	884.5
Kings	123	124,901	1,015.5
Tulare	317	379,318	1,196.6
Madera	51	69,795	1,368.5
TOTAL	1,159	954,301	823.4

Annex G2: Data Accuracy

Discussion on the accuracy of the data for Merced County

While the California Dairy Information Bulletin reports that Merced County has experienced a steady loss in the number of farms over the last five years, the amount of loss does not account for the 50% discrepancy in data. The data file provided by the Water Quality Control board had 51% the entries with no cow data reported. Jess Sitre of the Merced County Dairy Program provided some additional records dairy records with cow counts for Merced County. The data between the two sources was merged into one file. Based on the merged files we have approximately 60% of the dairy information for all of Merced County and at least 75% of all data for the area of interest surrounding the Merced County CNG filling station.

While the Merced cow data is not completely accurate we were provided the Merced dairy locations from two different sources; Jess Sitre and Polly Lowry. Both sources provided the exact same locations for 331 dairies. Therefore, we believe the dairy farm information provided to be very accurate. The missing cow data only impacted the analysis of the Merced CNG station. In instances where data on the number of cows were missing, we simply employed the county average of cows per farm. While an approximation, we feel confident that the analysis will be within 20% the number of cows in the area surrounding the CNG station.

California Counties: Cows, Dairies, and Cows per Dairy
Number of milk cows and heifers that have calved on farms,
number of dairies, and average number of cows per dairy
in California by counties and regions, 1998 and 1999

County	1998 Number Cows	1998 Number Dairies [2/]	1998 Average Number Cows/Dairy	1999 Number Cows	1999 Number Dairies [2/]	1999 Average Number Cows/Dairy
Fresno	84,172	106	794	84,172	105	802
Kings	109,512	151	725	124,668	146	854
Madera	32,021	49	653	35,507	52	683
Merced	178,241	336	530	185,130	338	548
San Joaquin	88,719	156	569	88,778	154	576
Stanislaus	142,546	319	447	146,285	323	453
Tulare	312,340	296	1,055	337,685	293	1,153
Total	947,551	1,413	671	1,002,225	1,411	710

[2/] Number of dairies source is Milk and Dairy Foods Control.

County	OUR DATA Number Cows	OUR DATA Number Dairies	OUR DATA Average Number Cows/Dairy	Percent Difference Our Data and 1999 Data Number Cows	Percent Difference Our Data and 1999 Data Number Dairies
Fresno	90,220	102	885	7%	-3%
Kings	124,901	123	1,016	0%	-16%
Madera	69,795	51	1,369	97%	-2%
Merced	118,959	343 [1]	598	-36%	+2%
San Joaquin	73,153	134	546	-18%	-13%
Stanislaus	130,494	271	482	-11%	-16%
Tulare	379,318	317	1,197	12%	8%
Total	954,301	1,159	823		

1. 164 of the dairy farms reported from Merced did not include the number of cows located at the dairy.

Determining Location Accuracy

To determine the accuracy of the GIS information we were provided, a comparison was made of geocodes from multiple sources. We also had geocode information for dairies from Tele Atlas and D&B. Tele Atlas is an internet geocode service at <http://www.geocode.com>. A random sampling of 23 dairies comparing the geocodes between the dairy records from the state and county and Tele Atlas and the dairy record and D&B revealed the following variance between the sourced. D&B geocodes were not available for 11 of these dairies. Some variance is to be expected because the geocodes are for different locations on the dairy. The Merced County Dairy Program indicated that it takes geocodes from the front door of the barn. Tele Atlas is providing geocodes based on the postal address and it returns a code for a location along the street. The source of D&B geocodes is not known. Assuming that up to 1 mile is an acceptable variance based on the different locations the geocodes were taken from then there is an 87% accuracy rate between the state supplied records and Tele Atlas and there is a 75% accuracy rate between the state supplied records and D&B. Of the three sources of data D&B is assumed to be the least accurate and this data was used only for plotting businesses in high natural gas usage industries.

The accuracy rate between Tele Atlas and the state supplied records can be determined for the total population. Based on the 87% accuracy rate for the 23 records sampled and using a 95% confidence level it can be determined that the total population accuracy rate is between these two sources would be between 73% to 99%.

Inaccuracy between the sources does not mean that the state and county records were inaccurate. The accuracy of the three sources can not be determined without taking new geocode reading. Since the state and county supplied records were based on actual readings and Tele Atlas geocodes are computed using the address of record, we assume that the state supplied geocodes are more accurate than the Tele Atlas geocodes. The geocodes from the state were used in our analysis. Tele Atlas geocodes were used for two dairy records that were supplied without geocodes but with addresses.

Accuracy of Geocodes between the Records Received from the
Water Quality Control Board and Tele Atlas and D&B

Mile Variance Comparison to Tele Atlas

Miles Variance	***Frequency***	**Percent**
0-.49	19	83%
.5-.99	1	4%
1.0-1.49	1	4%
1.5-1.99	0	0%
2 or More	2	9%
	23	100%

Mile Variance Comparison to D&B

Miles Variance	***Frequency***	**Percent**
0-.49	8	67%
.5-.99	1	8%
1.0-1.49	1	8%
1.5-1.99	0	0%
2 or More	2	17%
	12	100%

We were not provided geocodes for the CNG stations. Geocodes for CNG stations were determined from two different sources and compared. The geocodes from both sources were determined based on the CNG street address. The first source we used to identify CNG geocodes was Tele Atlas, an internet geocode service at <http://www.geocode.com>. The second source of geodes was the California State University, Fresno Interdisciplinary Spatial Information Systems Center (ISIS). The two CNG stations for which there was a discrepancy of more than one tenth of a mile only occurred when Tele Atlas could not identify an exact location based on the street address and provided an approximate location. All of the other variances were less than 125 feet.

The Waste Treatment Plants file provided to us was not geocoded. We determined geocodes for these locations using Tele Atlas. The landfill location and the business locations were provided with geocodes and these geocodes were not verified. Based on the verification process that we undertook we found the geocodes provided to be highly accurate.

Annex G3: CNG Filling Stations

Name	Phone	Address	City	State	Zip	Type of Access	County
California State University at Fresno	800-723-9398	385 E Barstow Ave	Fresno	CA	93710	Public with restrictions; card key required	Fresno
City of Fresno Service Center	800-684-4648	1900 E St	Fresno	CA	93706	Public with restrictions; card key required	Fresno
Clovis Unified School District	800-723-9398	1450 Herndon Avenue	Clovis	CA	93611	Government Personnel only	Fresno
Gibbs Automated Fuel Station	800-684-4648	3555 S Academy Ave	Sanger	CA	93657	Public with restrictions; card key required	Fresno
Kings Canyon Unified School District	213-244-5215	675 W Manning Avenue	Reedley	CA	93654	Private Station; limited access	Fresno
Pinnacle CNG/UPS	915-686-6487	1601 W McKinley Ave	Fresno	CA	93728	Public with restrictions; card key required	Fresno
Visa Petroleum	800-723-9398	2414 Monterey Street	Fresno	CA	93721	Public with restrictions; card key required	Fresno
Kings County Yard/PFC	888-732-6487	11827 S 11th Ave	Hanford	CA	93230	Public with restrictions; card key required	Kings
Lemoore NAS	213-244-5215	25000 Coalinga Highway - Transportation Division Building 765, NAS Lemoore	Lemoore	CA	93246	Government Personnel only	Kings
Tesei Petroleum	(559) 673-3597	1300 S. Gateway Drive	Madera	CA	93637	Public Access Allowed	Madera
PG&E Merced Service Center	800-684-4648	3185 M St	Merced	CA	95348	Public with restrictions; card key required	Merced
E.F. Kludt and Sons	(209)368-0634	1126 E. Pine Street	Lodi	CA	95241	Public Access Allowed	San Joaquin
PG&E Stockton Service Center	800-684-4648	4040 West Ln	Stockton	CA	95204	Public with restrictions; card key required	San Joaquin
San Joaquin County	209-468-3380	1810 E Hazelton Ave	Stockton	CA	95201	Private Station; limited access	San Joaquin
W.H. Breshear's - FleetStar	800-723-9398	428 7th Street	Modesto	CA	95354	Public with restrictions; card key required	Stanislaus
City of Tulare - FleetStar	800-723-9398 or 800-685-2376	3989 S K Street	Tulare	CA	93274	Public with restrictions; card key required	Tulare
FleetStar - SoCal Gas	800-723-9398	320 N Tipton Street	Visalia	CA	93292	Public with restrictions; card key required	Tulare

Annex G4: Analysis of Sites 5 through 8

Site #5 - PG&E Merced Service Center

The fifth ranked location is the PG&E Merced Service Center

3185 M St
Merced, CA 95348

This CNG location allows public access with restrictions.

Cows	68,600
Dairies	92
Avg. No. of Cows	746
Annual biomethane Production Potential (million ft^3)	751
Landfills	3
Wastewater plants	0

This facility is located in the center of the city of Merced. The city of Merced is located in Merced County. According to the 2000 US Census the city of Merced had a population of 63,893. The facility is within two and a half miles of Highway 99. Of the 92 dairies in the surrounding area, all are located in Merced County.

No wastewater treatment plants are located in the 400-square-mile area surrounding this site.

The landfills located in the 20-square-mile area surrounding this site are listed below. For more information about the landfills see Annex G7. None of the landfills are common to any other site. All three landfill sites have the same address and are located approximately 6 miles south of the CNG station.

1. Highway 59 Compost Facility
   6040 N. Highway 59
   Merced, CA 95340

2. Highway 59 Research Composting Op.
   6040 N. Highway 59
   Merced, CA 95340

3. Highway 59 Disposal Site
   6040 N. Highway 59
   Merced, CA 95340

There are five businesses in the area surrounding this location that represent industries that use large amounts of natural gas. Based on the industries' sales and national average industry natural gas usage it is estimated that these four locations would use a total of 305,975,000 kBtu/year. These five businesses represent a small additional demand. The five businesses are:

1. Oasis Foods Inc
   9341 E Childs Ave
   Planada, CA 95365
   Fruits and fruit products, in cans, jars, etc
   Estimated Natural Gas usage = 33,640,000 kBtu/year

2. Pacific-Sierra Publishing Inc
   3032 G St
   Merced, CA 95340
   Newspapers, publishing and printing
   Estimated Natural Gas usage = 33,400,000 kBtu/year

3. CHEFS PRIDE
   2751 N Santa Fe Dr
   Merced, CA 95348
   Meat packing plants
   Estimated Natural Gas usage = 38,397,000 kBtu/year

4. Teasdale Quality Foods
   901 Packers St
   Atwater, CA 95301
   Tomato products, packaged in cans, jars, etc.
   Estimated Natural Gas usage = 53,940,000 kBtu/year

5. J R Wood Inc
   7916 Bellevue Rd
   Atwater, CA 95301
   Fruits, quick frozen and cold pack (frozen)
   Estimated Natural Gas usage = 146,598,000 kBtu/year

The three landfills in the area provide a poor potential number of collaborating partners that could help provide a steady flow of methane for refining and/or help build markets for biomethane. The five businesses in the area that are in high natural gas industries represent a small potential for additional demand of biomethane.

Site #6 – Lemoore NAS

The sixth site is located near the Lemoore Naval Air Station. All of the characteristics of this site are shared with Site #3. For further information about this location see Site #3.

Site #7 - Kings Canyon Unified School District

The seventh ranked location is Kings Canyon Unified School District. The address is:

675 W Manning Avenue
Reedley, CA 93654

This CNG location is a private station with limited access.

Cows	40,048
Dairies	30
Avg. No. of Cows	1,335
Annual biomethane Production Potential (Million ft^3)	438
Landfills	0
Wastewater Plants	0

This facility is located in the center of the City of Reedley. Reedley is located in Fresno County. According to the 2000 US Census (2002), Reedley had a population of 20,756. The facility is 11 miles from Highway 99. Of the 30 dairies in the surrounding area, 5 are in Fresno County, 3 are in Kings County and 22 are in Tulare County. The largest dairy in the valley, the Boertje Dairy, with 12,000 cows is located in the surrounding area and skews the average number of cows per dairy. The data did not show any active landfills or wastewater plants in the area currently utilizing methane.

One other CNG Filling Station is located within the surrounding area. The Gibbs Automated Fueling Station is located in Sanger to the northwest of this location. The Gibbs Automated Fueling Station is a public station with restricted access.

There are five businesses in the area surrounding this location that are in high natural gas using industries. Based on the industries' sales and national average industry natural gas usage it is estimated that these four locations would use a total of 678,420,000 kBtu/year. These five businesses represent a good additional demand for biomethane, the largest potential demand of all Sites that are highlighted. The five businesses are:

1. Kaweah Container Inc
   13291 Avenue 404
   Cutler, CA 93615
   Corrugated and solid fiber boxes
   Estimated Natural Gas usage = 91,907,500 kBtu/year

2. Nutrient Technologies Inc
   1092 E Kamm Ave
   Dinuba, CA 93618
   Fertilizers: natural (organic), except compost
   Estimated Natural Gas usage = 73,602,000 kBtu/year

3. Ruiz Food Products Inc
   501 S Alta Ave
   Dinuba, CA 93618
   Ethnic foods, nec, frozen
   Estimated Natural Gas usage = 229,745,000 kBtu/year

4. Sanger Wrks Fctry Holdings
   1949 E Manning Ave
   Reedley, CA 93654
   Packaging machinery
   Estimated Natural Gas usage = 32,648,500 kBtu/year

5. Sun-Maid Growers California
   13525 S Bethel Ave
   Kingsburg, CA 93631
   Raisins
   Estimated Natural Gas usage = 250,517,000 kBtu/year

The lack of landfills and wastewater treatment plants in the surrounding area means that there are no potential collaborating partners to provide alternative sources of methane or to help market biomethane. The five businesses in the area that are in high natural gas industries represent a good potential for additional demand of biomethane.

Site #8 – Tesei Petroleum

The eighth ranked location is Tesei Petroleum in Madera. The address is:

1300 S. Gateway Drive
Madera, CA 93637

This CNG location allows public access.

Cows	30,488
Dairies	30
Avg. No. of Cows	1,016
Annual biomethane Production Potential (Million ft^3.)	338
Landfills	2
Wastewater plants	0

This facility is located on the southern half of the city of Madera. The city of Madera is located in Madera County. According to the 2000 US Census (2002) the city of Madera had a population of 43,207. The facility is less than one tenth of a mile from Highway 99. Of the 48 dairies in the surrounding area, 45 are located in Madera County and 3 are located in Fresno County. The surrounding area does not overlap with any other highlighted sites.

No wastewater treatment plants are located in the area surrounding this site. The two landfills located in the area surrounding this site are listed below. For more information about the landfills see Annex G7.

1. Mammoth Recycling Facility
   21739 Road 19
   Chowchilla, CA 93610

2. Fairmead Solid Waste Disposal Site
   Avenue 22 At Road 19
   Chowchilla, CA 93610

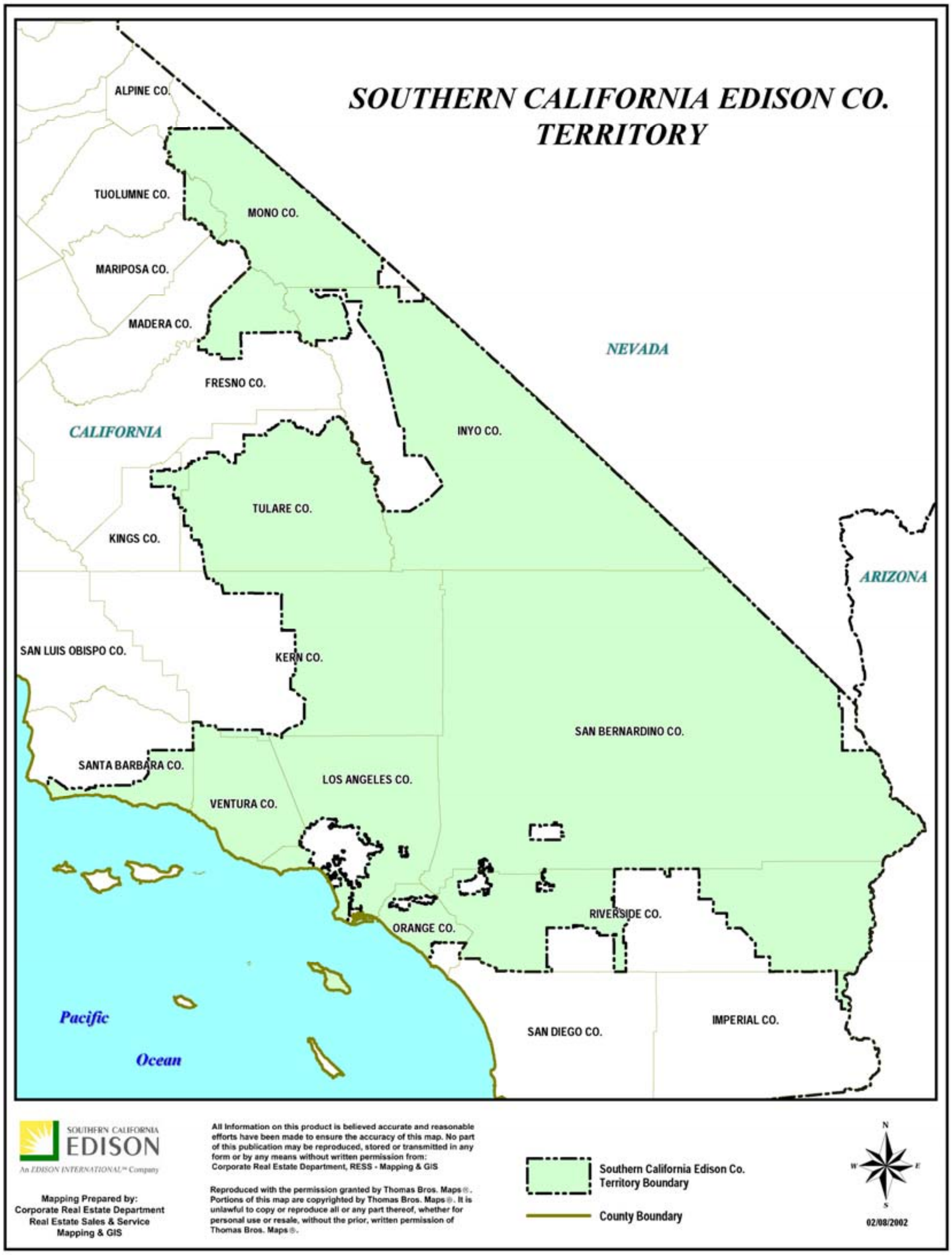
No other CNG Filling stations are located within the surrounding area.

There is 1 business in the 400 square mile area surrounding this location that is in high natural gas using industries. Based on the industries' sales and national average industry natural gas usage it is estimated that these five locations would use a total of 62,524,000 kBtu/year. This business represents a very small additional demand. The business is:

Canandaigua Wine Company Cal
12667 Road 24
Madera, CA 93637-9020
Wines, brandy, and brandy spirits
Estimated Natural Gas usage = 62,524,000 kBtu/year

The two landfills in the area provide a poor potential number of collaborating partners that could help provide a steady flow of methane for refining and/or help build markets for biomethane. The one business in this area represents a very poor potential for an alternative demand for biomethane Site #7 represents the smallest potential alternative use of biomethane of all the sites highlighted.

Annex G5 – Southern California Edison Service Territory



(Source: Southern California Edison, no date)

Annex G6: Wastewater Treatment Plants

Biomass

Plant Name (Alias)	Facility	Fuel Source (Cogen)	Technology	Online <MW)< B>	Service Area	County	Plant Address	Plant Phone	Operator / Owner (if different)	Operator-Contact / Owner-Contact	Operator-Phone# / Owner Phone#	Operator-Address / Owner Address
Auberry Energy	WTE	Biomass - Ag. & Woodwaste (Cogen)		7.5	PG&E	Fresno	32180 Auberry Road New Auberry 93602	209-855-4001	Auberry Energy Inc	Doug Thompson	209-855-4001	32180 Auberry Rd, Auberry Ca 93602
Delano Energy I-Ii	WTE	Biomass - Ag. & Woodwaste		49.9	SCE	Kern	31500 Pond Road Delano 93215	805-792-3062	Delano Power Co Thermo Ecotek	Dale Hale Or Tony Collins Tony Collins Or Jimmy Hakimiam	805-792-3067 805-792-3067	31500 Pond Rd, Po 1461, Delano Ca 93215
Mendota Biomass Power	WTE	Biomass - Ag. & Woodwaste (Cogen)	Fluidized Boiler	25	PG&E	Fresno	400 Guillen Parkway Mendota 93640	209-655-4921	Mendota Biomass Power Thermo Ecotek	Glen Sizemore Or Bob Notoheis	209-655-4921	400, Guillen Pkwy, Po Box 99, Mendota Ca 93640
Tracy Biomass	WTE	Biomass - Ag. & Woodwaste		21	PG&E	San Joaquin	14800 W. Schultz Road Tracy 95376	209-835-6914	Tracy Operators Community Energy Alternatives Inc (Cea)	Larry K. Lien Art Nislick	209-835-6914 201-652-2772	Po Box 1211, Tracy Ca 95378-1211 1200 E. Ridgewood Ave, Ridgewood Nj 07450
Diamond Walnut Growers	WTE	Biomass - Ag. Waste - Walnut Sh (Cogen)		4.5	PG&E	San Joaquin	1050 South Diamond Street Stockton 95205	209-467-6000	Diamond Walnut Growers Inc.	James Wagner Or Bo Thisted	209-467-6000	1050 S. Diamond St, Stockton Ca 95205
California Cedar Products	WTE	Biomass - Woodwaste (Cogen)		0.85	PG&E	San Joaquin	1340 W. Washington Street Stockton 95201	209-944-5800	California Cedar Products	Patrick Lam	209-944-5800	1340 W. Washington , Stockton Ca 95202

Annex G6: Wastewater Treatment Plants (continued)

Digester Gas

Plant Name (Alias)	Facility	Fuel Source (Cogen)	Technology	Online <MW)< B>	Service Area	County	Plant Address	Plant Phone	Operator / Owner (if different)	Operator-Contact / Owner-Contact	Operator-Phone# / Owner Phone#	Operator-Address / Owner Address
City Of Tulare	WTE	MSW - Digester Gas		0.41	SCE	Tulare	1875 South West Street Tulare		City Of Tulare	Milton Preszler		411 E. Kern Ave, Tulare 93274
Roy Sharp Jr.	WTE	MSW - Digester Gas		0.1	PG&E	Fresno	Caruthers					
Royal Farms #1-#2	WTE	MSW - Digester Gas		0.18	SCE	Tulare	Address Confidential Tulare 93274	209-686-9779	Royal Farms	Confidential	Confidential	Confidential

Industrial Waste

Plant Name (Alias)	Facility	Fuel Source (Cogen)	Technology	Online <MW)< B>	Service Area	County	Plant Address	Plant Phone	Operator / Owner (if different)	Operator-Contact / Owner-Contact	Operator-Phone# / Owner Phone#	Operator-Address / Owner Address

Landfill Gas

Plant Name (Alias)	Facility	Fuel Source (Cogen)	Technology	Online <MW)< B>	Service Area	County	Plant Address	Plant Phone	Operator / Owner (if different)	Operator-Contact / Owner-Contact	Operator-Phone# / Owner Phone#	Operator-Address / Owner Address
Fresno Wwtp	WTE	MSW - Landfill Gas		1.3	PG&E	Fresno	5607 West Jenson Avenue Fresno 93706	209-277-1475	Fresno Wastewater Treatment		209-498-1707	5607 West Jenson Ave, Fresno Ca 93706
Pacific Energy (Stockton)	WTE	MSW - Landfill Gas		0.8	PG&E	San Joaquin	9075 S. Austin Road Stockton 95206	209-462-4206	Pacific Energy Ogden Energy Group, Inc.	Denice Marsh	209-462-4206	9595 S. Austin Rd, Stockton Ca 95206
Tulare County Landfill	WTE	MSW - Landfill Gas	Gas Turbine Combined Cycle	1.9	SCE	Tulare	26951 Road 140 Visalia 93292		Minnesota Methane			

Annex G6: Wastewater Treatment Plants (continued)

Municipal Solid Waste

Plant Name (Alias)	Facility	Fuel Source (Cogen)	Technology	Online <MW)< B>	Service Area	County	Plant Address	Plant Phone	Operator / Owner (if different)	Operator-Contact / Owner-Contact	Operator-Phone# / Owner Phone#	Operator-Address / Owner Address
Modesto Energy	WTE	MSW - Tires		14	PG&E	Stanislaus	4549 Ingram Creek Road Westley 95387	209-894-3161	Modesto Energy Co. Oxford Energy	 Carl Levesque	209-894-3161 209-894-3161	Po Box 302, Westley Ca 95837
Covanta Stanislaus Inc. (Stanislaus Waste Energy)	WTE	MSW - Waste		18	PG&E	Stanislaus	4040 Fink Road Crows Landing 95313	209-837-4423	Covanta Stanislaus Inc. Ogden Martin	 Fred Engelhardt	209-837-4423 209-837-4423	

Annex G7: Landfills and Disposal Sites

Name	Land Use Name	County	Location	Place
American Avenue Disposal Site	Agricultural	Fresno	18950 W American Av 4 Mi W/O Madera Av	Tranquillity
Cedar Ave. Recycling & Transfer Station	Industrial, Commercial	Fresno	3457 S. Cedar Avenue	Fresno
City Of Clovis Landfill	Rural	Fresno	15679 Auberry Road	Fresno
Coalinga Disposal Site	Rural	Fresno	30825 Lost Hills Road	Coalinga
Craycroft Brick Inert Site		Fresno	2301 W Belmont @ Marks	Fresno
Gallo Vineyards, Inc Compost Operation	Agricultural	Fresno	5686 East Olive Avenue	Fresno
Jefferson Avenue Transfer Station	Industrial, Agricultural	Fresno	5608 Villa Avenue	Fresno
Jefferson Inert Disposal Site		Fresno	Jefferson & Maple	Fresno
Kochergen Property Grease Trap Disposal	Rural	Fresno	15485 W Republic	Huron
Orange Avenue Disposal Inc	Industrial	Fresno	3280 South Orange Ave	Fresno
Shaver Lake Transfer Station	Rural	Fresno	1 Mi E of Hwy 168 on Dinkey Creek Rd	Shaver Lake
Sunset Wastepaper MRF and TS	Residential, Open Space, Industrial	Fresno	2721 S. Elm Avenue	Fresno
Avenal Landfill	Residential, Industrial, Commercial, Agricultural	Kings	201 North Hydril Road	Avenal
CWMI - B18 Nonhazardous Codisposal	Agricultural	Kings	35251 Old Skyline Road	Kettleman City
CWMI Kettleman Hills Facility	Agricultural	Kings	35251 Old Skyline Road	Kettleman City
Kochergen Farms Composting	Agricultural	Kings	Avenal Cutoff Rd. and Omaha Ave.	Avenal
KWRA Composting Facility	Agricultural	Kings	7803 Hanford-Armona Road	Hanford
KWRA Material Recovery Facility	Agricultural	Kings	7803 Hanford-Armona Rd.	Hanford
Emadco Transfer Station	Residential	Madera	Black Oak River Road	Oakhurst
Fairmead Solid Waste Disposal Site	Rural, Residential, Agricultural	Madera	Avenue 22 At Road 19	Chowchilla
Mammoth Recycling Facility And TS	Rural	Madera	21739 Road 19	Chowchilla
North Fork Transfer Station	Rural	Madera	33699 Road 274	North Fork

Annex G7: Landfills and Disposal Sites (continued)

Name	Land Use Name	County	Location	Place
A&D Transport		Merced	25077 West Hearst Road	Gustine City
Atlas Materials Inc. - White Crane Ranch	Rural	Merced	11550 West Highway 140	Atwater
Billy Grissom Fertilizer	Agricultural	Merced	5331 Columbus Ave	Hilmar
Billy Wright Composting Facility		Merced	17173 Billy Wright Road	Los Banos
Billy Wright Disposal Site		Merced	Billy Wright Rd; 1 Mi West of I-5	Los Banos
Foster Farms Manure Storage Facility	Range Land, Open Space, Industrial, Agricultural	Merced	12997 W. Highway 140	Atwater
Highway 59 Compost Facility	Wetlands, Rural, Agricultural	Merced	6040 N. Highway 59	Merced
Highway 59 Disposal Site	Wetlands, Open Space, Agricultural	Merced	Hwy 59; 6 Mi N Merced	Merced
Highway 59 Research Composting Op.		Merced	6040 North highway 59	Merced
Kenneth Stone & Family Spreading Service		Merced	W. of Lupin Ave& 1/4 Mile N. of Palm Ave	Winton
Nakashima Farms Composting		Merced	10397 West Walnut Avenue	Livingston
Robeson Farms		Merced	Le Grand	Le Grand
Stone Family El Nido Composting Facility	Agricultural	Merced	Vineyard Way At Grant Road	Merced
Valley Fresh Foods Inc.	Agricultural	Merced	1220 Hall Road	Merced
A-Plus Materials Recycling, Inc.		San Joaquin	Port 23 Port of Stockton	Stockton
Central Valley Waste Services		San Joaquin	1333 East Turner Road	Lodi
Central Valley Waste Services		San Joaquin	1333 E. Turner Road	Lodi
Delicato Vineyards	Agricultural	San Joaquin	12001 S. Hwy 99, Manteca	Manteca
East Stockton Transfer & Recycling Stn	Residential, Industrial, Commercial	San Joaquin	2435 East Weber Avenue	Stockton
Foothill Sanitary Landfill	Range Land	San Joaquin	6484 North Waverly Road	Linden
Forward Landfill, Inc.	Residential, Range Land, Agricultural	San Joaquin	9999 S. Austin Road	Manteca
Forward Resource Recovery Facility		San Joaquin	9999 S. Austin Road	Manteca
Jensen Farms Compost Operation		San Joaquin	5793 West Delta Avenue	Tracy
Lovelace Transfer Station		San Joaquin	2323 Lovelace Road	Manteca

Annex G7: Landfills and Disposal Sites (continued)

Name	Land Use Name	County	Location	Place
Nilsen Farms		San Joaquin	17200 Liberty Road Galt, CA 95632	Acampo
North County Recycling Ctr.& Sanitary LF	Residential, Industrial, Agricultural	San Joaquin	17900 East Harney Lane	Victor
Scotts Regional Composting Facility	Agricultural	San Joaquin	23390 Flood Road	Linden
Stockton Recycling & Transfer Station		San Joaquin	401 South Lincoln Street	Stockton
Super Pallet Recycling Corporation	Residential, Park, Industrial, Commercial	San Joaquin	2430 South California Street	Stockton
Tracy Material Recovery & T.S.	Rural	San Joaquin	30703 S. Macarthur Drive	Tracy
USA Waste of California, Inc	Industrial	San Joaquin	1240 Navy Drive	Stockton
Bertolotti Transfer & Recycling Center	Commercial	Stanislaus	231 Flamingo Drive	Modesto
Bonzi Sanitary Landfill	Rural	Stanislaus	2650 West Hatch Road	Modesto
Central Valley Agricultural Grinding, Inc		Stanislaus	5707 Langworth Road	Riverbank
City Of Modesto Co-Compost Project	Agricultural	Stanislaus	7007 Jennings Road, Modesto	Modesto
City of Turlock Waster Qual. Control Fac		Stanislaus	901 South Walnut Road	Turlock
Covanta Stanislaus, Inc.		Stanislaus	4040 Fink Road	Crows Landing
Fink Road Landfill	Rural	Stanislaus	4000 Fink Road	Crows Landing
Gilton Resource Recovery CandD Proc Fac.		Stanislaus	800 South McClure Road	Modesto
Gilton Resource Recovery Composting Fac.	Industrial	Stanislaus	800 S. McClure Rd.	Modesto
Gilton Resource Recovery/Transfer Fac	Industrial	Stanislaus	800 McClure Road	Modesto
Grover Environmental Products/Salida	Industrial	Stanislaus	6131 Hammett Road	Modesto
Grover Environmental Products/Vernalis	Open Space, Agricultural	Stanislaus	3401 Gaffery Road	Vernalis
Modesto Disposal Svc TS/Res Rec Fac	Residential	Stanislaus	2769 West Hatch Road	Modesto

Annex G7: Landfills and Disposal Sites (continued)

Name	Land Use Name	County	Location	Place
Turlock Transfer	Industrial	Stanislaus	1100 South Walnut	Turlock
Valley Wood Disposal		Stanislaus	1800 reliance Street	Modesto
Badger Transfer Station	Rural	Tulare	Road 260 At Avenue 468	Badger
Balance Rock Transfer Station	Rural	Tulare	Balance Rock Landfill	California Hot Springs
Camp Nelson Transfer Site	Rural	Tulare	1/4 Mi N Camp Nelson	Camp Nelson
Earlimart Transfer Station	Agricultural	Tulare	7012 Road 136	Earlimart
Kennedy Meadows Transfer Station	Rural	Tulare	Goman Road West Of M-152 Station	Johnsondale
New Era Farm Service #1		Tulare	Hoffman Dairy Ave 216 & Rd 140	Tulare
New Era Farm Service #2		Tulare	Jim Nance Dairy 6440 Ave 160	Tulare
Pine Flat Transfer Station	Rural	Tulare	1/4 Mi S Pine Flat	California Hot Springs
Soil Foods, Inc.		Tulare	20002 Road 140	Tulare
Springville Transfer Station	Rural	Tulare	Avenue 122 At Road 338	Springville
Sunset Material Recovery Facility		Tulare	1707 East Goshen Road	Visalia
Teapot Dome Disposal Site	Rural, Residential, Agricultural	Tulare	Avenue 128 And Road 208	Porterville
Tulare County Compost And Biomass	Rural	Tulare	24487 Road 140	Tulare
Tulare County Recycling Complex	Rural	Tulare	26951 Road 140, Visalia	Visalia
Visalia Disposal Site	Rural, Agricultural	Tulare	Road 80 At Avenue 332	Visalia
Wood Industries Co	Agricultural	Tulare	7715 Ave. 296	Visalia
Woodville Disposal Site	Rural	Tulare	Rd 152 At Ave 198; 10 Mi Se Tulare	Tulare