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 $0.62 (for a $4,500/kw digester) to $0.77/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 ($ per 1,000 ft^3) biomethane			
Cost Category	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

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[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.

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

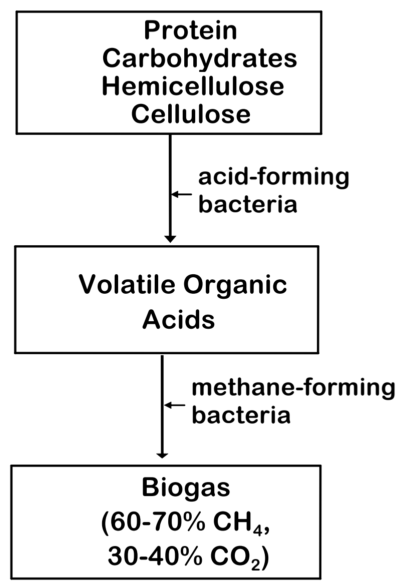

Figure 2-2 Simplified process of biogas production

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° F (mesophilic)	~130° F(thermophilic)	100° 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.

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

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.

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.

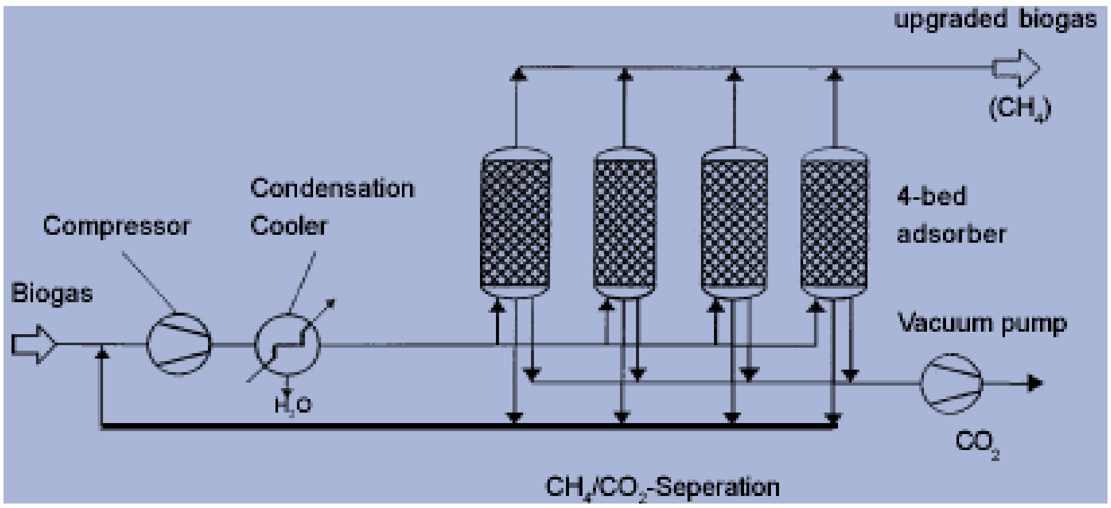

Figure 3-2 Schematic of a pressure swing absorption system with carbon molecular sieves for upgrading biogas

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

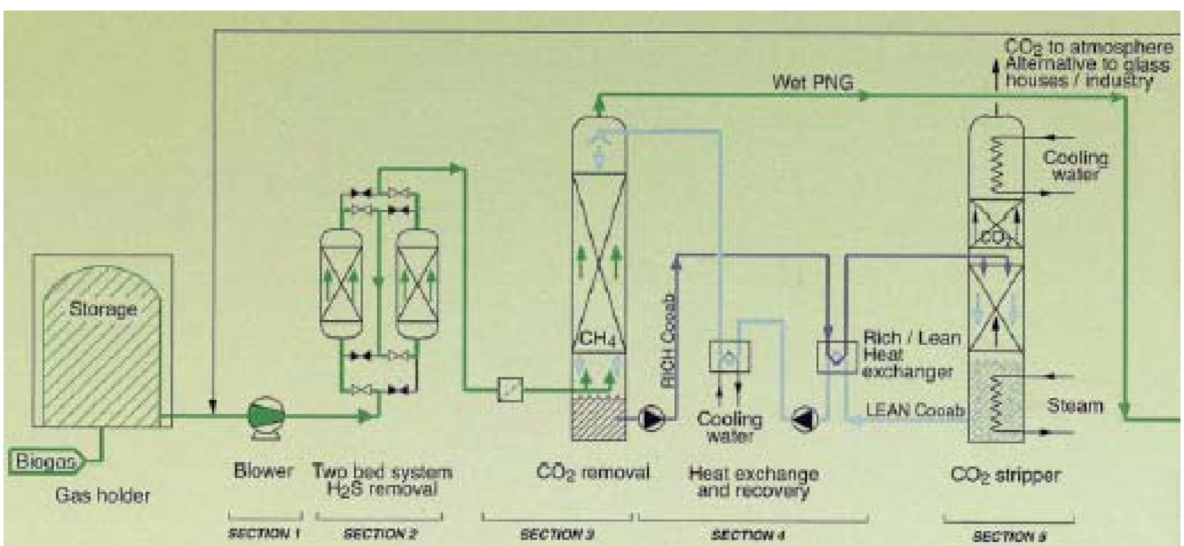

Figure 3-3 Cirmac amine carbon dioxide absorption process (LP Cooab™) for upgrading biogas (Source: Cirmac, Undated)

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

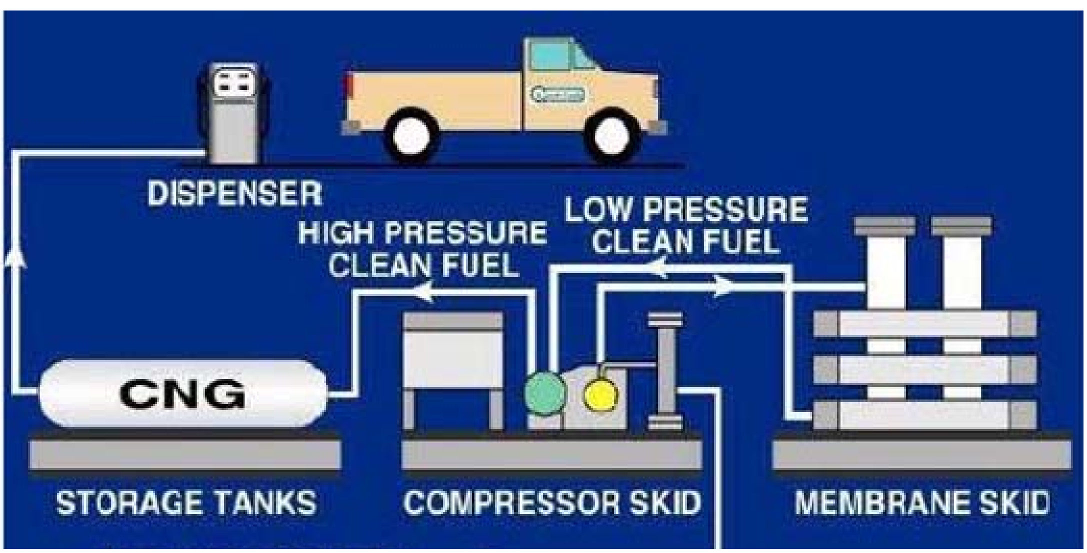

Figure 3-4 Schematic of Puente Hills landfill gas carbon dioxide – methane separation process (Source: Sanitation Districts of Los Angeles County, http://www.lacsd.org/swaste/Facilities/LFGas/CNGFacility.htm)

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.

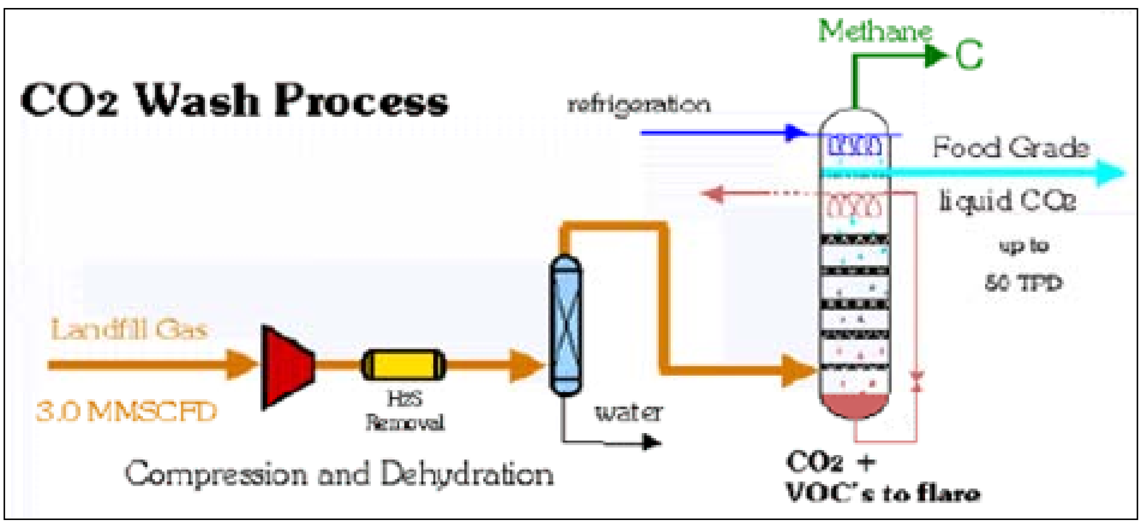

Figure 3-5 Carbon dioxide scrubbing process developed by Acrion Technologies (source: Acrion Co. <www.acrion.com>)

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.

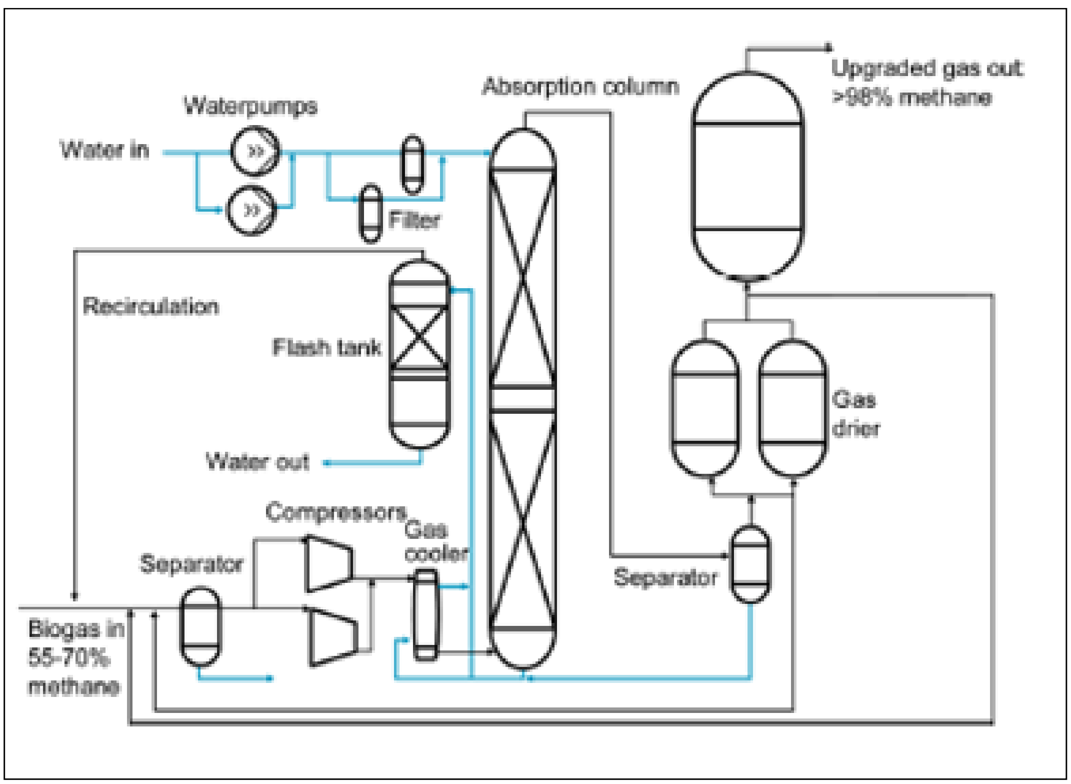

Figure 3-6 Water scrubbing process to remove carbon dioxide from biogas without regeneration (source: Hagen et al., 2001, Figure 7)

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.

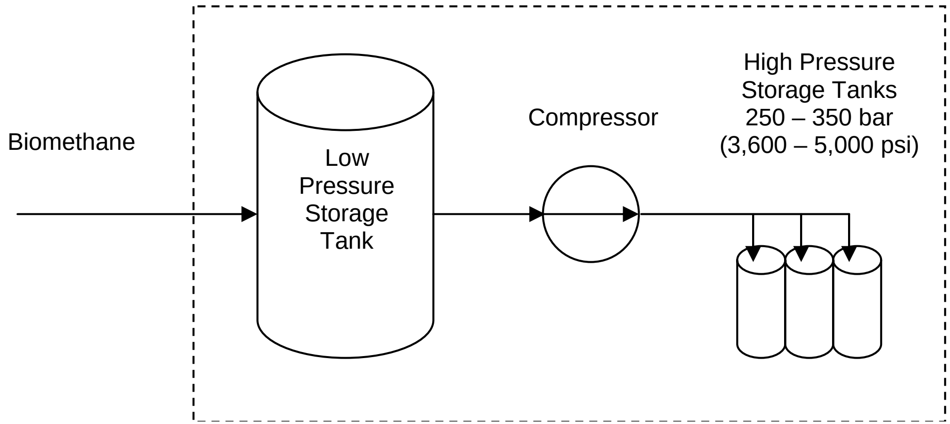

Figure 4-1 Schematic of on-farm storage system for compressed biomethane

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.

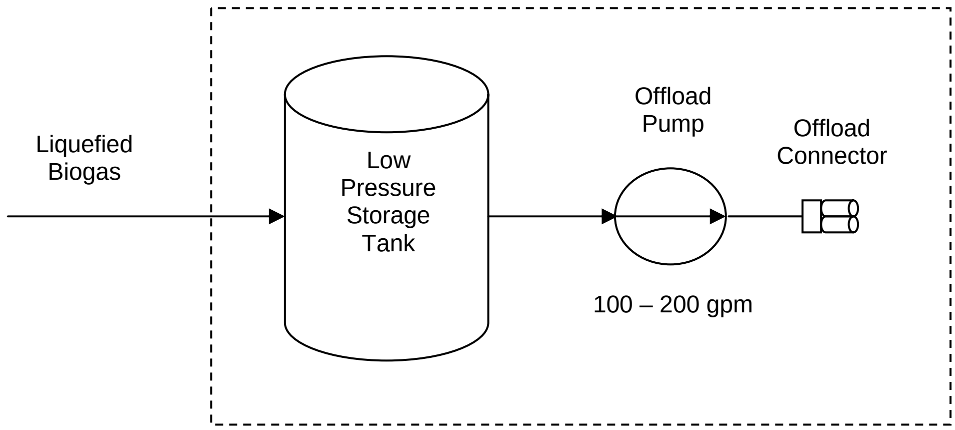

Figure 4-2 Schematic of storage system for liquefied biomethane

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.