

Utilization

Handbook



the Environment, Health, and Safety Division Georgia Tech Research Institute Atlanta, Georgia sponsored by Southeastern Regional Biomass Energy Program and

ate of Georgia through the Georgia Poultry Federation



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INTRODUCTION

Biogas is a combination of methane, carbon dioxide, and other constituents produced by the anaerobic digestion of hydrocarbons. For many years, biogas was considered a waste product of anaerobic sludge digestion systems, and was simply flared off to prevent injury to personnel. In fact, some plants converted to aerobic digestion systems to eliminate this and other problems associated with anaerobic sludge disposal systems. At covered landfills, biogas was a nuisance which would simply migrate out of the ground. Many landfills installed peripheral gas collection systems and flares to burn the gas and prevent injury to personnel as well as the surrounding community.

The energy crisis initiated by the 1973 Arab oil embargo brought a new awareness of the use of renewable fuels, including biogas. Subsequently, a number of projects sponsored by the U. S. Department of Energy (USDOE), other governmental funding agencies, and private industries, evaluated the use of anaerobic treatment systems for the production of energy. In addition, private enterprises have successfully recovered biogas from more than 200 landfills for production of thermal or electric energy. Although economic feasibility remains dependent upon waste characteristics, treatment system efficiency, and fluctuations in the energy market, these projects have clearly demonstrated the technical feasibility of anaerobic systems for the production of energy.

The interest in anaerobic systems has been furthered by more stringent pretreatment requirements imposed by many Publicly Owned Treatment Works (POTW's). Faced with making pretreatment choices and considering the rising cost of electric power in many localities, many industries favor low energy consumption systems such as anaerobic treatment. However, many of the industries which have chosen anaerobic processes simply flare the biogas produced, illustrating that anaerobic treatment is a good pretreatment alternative irrespective of the energy production potential.

One of the major obstacles to effective industrial use of biogas is the lack of a single source of information on the handling, storage, compression, clean-up, combustion, and safety equipment requirements. The information on the projects sponsored by the USDOE and other private or public organizations are scattered throughout the literature. Design and management strategies for energy recovery are unique with almost every new initiative, and manufacturers of equipment specifically designed for biogas are sometimes difficult to locate. A unifie approach and information clearinghouse are clearly needed to guide developmen efforts into the 1990's. This handbook is designed to provide a single source of information to help guide industries in their choice of technologies for cos effective utilization of biogas.

This handbook evolved from literature searches of available publications of landfills, wastewater pretreatment systems, and biogas utilization systems, and contains information on laboratory-, pilot-, and full-scale anaerobic treatmer systems and landfills. This information has been analyzed, condensed, and combine where appropriate to provide guidelines generic to most anaerobic treatmer systems. The handbook contains an extensive list of references, and the reader encouraged to use these to obtain more specific information on particular designs of operating strategies.

A list of suppliers for the equipment needed to recover and utilize the biogar from an anaerobic treatment system is contained in the appendix. These manufacturers were identified through a mail survey and the Thomas Register However, the listing does not include suppliers of common items such as pipe fittings, valves, gauges, etc. The authors do not wish to imply that the firms liste are the only manufactures of this equipment, and it is recommended that any firm considering the installation of a system consult publications such as the Thomas Register for other potential equipment suppliers. The Thomas Register can be foun in many libraries.

The handbook does not extract design information from national standards suc as those published by the American Society for Testing and Materials (ASTM), th American Society of Mechanical Engineers (ASME), and the American National Standards Institute (ANSI). In places where information from these standards is appropriate, the standard is referenced. The purpose of referencing these standard is to avoid any conflict between the handbook and these standards. These standards are updated and revised on a periodic basis, and the potential exists for future revision to conflict with recommendations set forth in this handbook. Befor finalizing a design, it is recommended that the most current ASTM, ASME, or othe applicable national and-local codes-be consulted.

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CHAPTER 2 SOURCES AND CHARACTERISTICS OF BIOGAS

Introduction

Biogas is a product of microbiological degradation processes. The primary sources of biogas in the United States are currently waste treatment system utilizing anaerobic digesters, or solid waste landfills. Both of these waste treatmen systems rely upon anaerobic bacteria to convert organic matter to methane (CH_4 and carbon dioxide (CO_2). The major differences between these processes is tha landfills are more analogous to batch digesters rather than continuous treatmen systems. Moreover, optimum conditions for methane production in landfills are established over a period of years rather than days, thus control requirements for landfills and continuous treatment systems vary greatly.

Anaerobic Treatment Fundamentals. Anaerobic treatment processes rely upon the microbiological degradation of organic wastes in an environment absent of molecular oxygen. Fundamentally, the process can be divided into three stages (Figure 2-1) with three distinct physiological groups of microorganisms. The process is briefly summarized here, and is discussed in more detail by McInerney and Bryant (1981).





Source: McInerney and Bryant 1981

The first stage involves the fermentative bacteria (and fungi in landfills including both anaerobic and facultative (aerobic/anaerobic) microorganism Complex organic materials, carbohydrates, proteins, and lipids are hydrolyzed an fermented into fatty acids, alcohols, carbon dioxide, hydrogen, ammonia, an sulfides.

In the second stage, acetogenic bacteria consume the primary organic produc and produce hydrogen, carbon dioxide and acetic acid. The third stage utilizes tw distinct types of methanogenic bacteria. The first reduces carbon dioxide a methane, and the second decarboxylates acetate to methane and carbon dioxide.

The objective of the biogas process is to completely degrade all organimaterial to methane. Therefore, it is important to optimize biochemical condition for all reactions leading to the formation of methanogenic precursors and, moimportantly, for those reactions responsible for the formation of methane itself. A the same time, production of carbon dioxide, nitrogen, and other gases which diluthe energy content of the gas should be minimized to the greatest extent possible.

Anaerobic Digesters

Anaerobic digesters are typically used for treating biological sludges, manure and other high solids wastes. These are most often intermittently fed a slurry of municipal or agricultural wastes at prescribed time intervals. In the reactor, th wastes are held at a certain temperature range for a specified retention time. The nature and composition of the wastes determines the optimum loading rate temperature, and retention time required for successful operation of the system Most systems are site-specific, and these variables are best determine experimentally for each individual operation. The type of digester used can var from simple plug-flow trench type to more complex multi-tank batch systems, of continuously fed and well-mixed continuously stirred tank reactors (CSTR's).

Due to their low cost and relative ease of operation, most farm digesters ar the plug-flow type. Process descriptions and discussions of the advantages an disadvantages of various digester types and their applications can be found i publications by the USEPA (1979c), Stafford (1980), Berdoll (1985), Walker <u>et a</u> (1985), Pratt <u>et al.</u> (1986), Sasser (1986), Walsh <u>et al.</u> (1986); and Splinter (1987).

Biogas from various sources varies in quality and is dependent upon certai factors. The composition of the biogas depends on the kinds of wastes bein digested, and the length of the retention time in which the waste undergoe

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digestion. The biogas produced from anaerobic digesters is a mixture of gases This mixture typically consists of 60-70% CH_4 , 30-40% CO_2 , and less than 1% hydrogen sulfide (H_2S). The H_2S levels are generally from about 100 to 2000 ppm, but levels as low as 2 ppm and as high as 8000 ppm have been reported. Trace amounts of nitrogen (up to 10%), hydrogen (up to 5%), oxygen, and various other constituents may also be present. However, as a result of their very small quantities, they are often very difficult to detect and most often inconsequential.

The production of biogas in digesters is influenced by a number of factors which are presented together with a general commentary in Table 2-1. In general potential gas production can usually be estimated from the volatile-solids (VS) loading of the digester and the percentage of VS reduction. Gas production rates can vary over a wide range, depending on the VS content of the sludge feed and the level of biological activity in the digester. Typical methane yields for various wastes, loading rates, temperatures and retention times are presented in Table 2-2.

<u>Landfills</u>

Biogas from landfills typically has a lower methane content (approximately 40-55%) than that of gas produced from digesters. The remaining volume is comprised primarily of carbon dioxide and a total of 1 to 2% of hydrogen sulfide and miscellaneous inorganic gases and organic vapors. Gas composition data from a number of full-scale landfill sites are listed in Table 2-3. The H₂S levels are usually less than 100 ppm, due in part to the low sulfur content of fill material and the complexation of H₂S with metal ions produced by landfill degradation. Unlike digester gas, landfill gas can contain a larger variety of trace constituents. A representative list of these constituents is compiled in Tables 2-4 and 2-5. The low concentrations of these constituents make them very difficult to detect, and their potential impact remains to be fully evaluated and documented.

Optimum conditions for methane production are rarely, if ever, observed in landfills. The rate of gas production may be limited by any of the contributing factors in Table 2-6. Methane production may be increased by monitoring and controlling (to a varying extent) these factors, as outlined by Harper and Pohland (1988).

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Table 2-1. Factors Affecting Digester Biogas Production

- Temperature most popular is within the mesophilic range of 80°F to 104° optimum occurs around 86°F to 95°F; thermophilic digestion also possible (113 to 141°F); small fluctuations from establishe effective temperature range can upset process.
- Retention Time depends on influent concentration, type of influent, and temperature. Typically 1 to 30 days in full-scale treatme systems and 10 to 20 years in landfills.
- Air must be excluded; toxic to anaerobic processes.
- Bacteria dependent upon waste and temperature; <u>Methanosarcina</u> mig be preferred for high rate methane production processes.
- C/N Ratio^{*} less than 43:1.
- C/P Ratio^{*} less than 187:1.
- pH successful range of 6.0-8.0; optimum is near 7.0.
- Volatile Acids bicarbonate alkalinity should exceed volatile acids alkalinity.
- Solid Contents optimum influent solids content is 7-9% by weight; but his rates have been observed at higher concentrations.
- Toxic Substances the presence of certain cations and heavy metals in sufficient concentrations are toxic to the anaerobic process; too numerou to generalize, but, in general, high concentrations of halogenated organics can be harmful.
- ** based on the anaerobic biomass approximation of C₅H₇NO₂P_{0.1} assumed by Pohland and Harper (1987b)

Source: Price (1981), ESCAP (1980), and Pohland and Harper (1987a)

Feed Slurry	Тетр (⁰ Ғ)	Loading (1b VS/ft ³ day)	Retentior Ti sc (days)	n Methane Yield (ft ³ /lb VS added)	Methane Content (vol %)	VS Reduction (%)	Productivity (ft ³ /lb TS)	Reference
Beef Manure	95	. 29	14	22.10 (1)	•	-	3.15	Safley (1986)
BeeE Manure	140	1.10	6	22.26 (1)	-	· -	3.20	Safley (1986)
Beef Manure	131	. 21	20	3.52	58	44.2		Price (1981)
Beef Manure	131	. 71	6	3,68	53	46.1		Price (1981)
Beef Manure	131	.47	9	4.48	52	-	•	Fannin (1982)
Dairy Manure	95	. 28	14	17.45 (1)	-	-	1.71	Safley (1986)
Dairy Manure	140	1.07	6	18.58 (1)	-	-	1.70	Safley (1986)
Dairy Manure	95	.44	12	. 78	65	21	-	Price (1981)
Dairy Hanure	91.	. 54	10	2.27	64	29	-	Price (1981)
Dairy Manure	99	. 25	13	3.52	60	42	•	Fannin (1982)
Swine Manure	95	. 25	14	24.50 (1)	-	-	4.10	Safley (1986)
Swine Manure	140	. 83	6	24.66 (1)	-	-	4.07	Safley (1986)
Swine Manure,	54	. 19	15	-	-	55	-	Smith (1980)
Poultry Manure	95	.17	14	53.65 (1)	-	-	3.99	Safley (1986)
Poultry Manute	140	.73	6	54.29 (1)	-	-	3.98	Safley (1986)
Poultry Manure	54	.15	40	*	-	55	•	Smith (1980)
Potatoe Tops	-	-	6	9.77	75	-	8.49	Stafford (1980)
Wheaten Straw	-	-	24	5.93	78	-	5.60	Stafford (1980)
Wheat Starch Brewerv	95	. 03	•	•	-	91 (7)	.18 (8)	Joseph Oat Corp. (
By Products	99	. 37	10	4.80	60-65	•	•	Fannin (1982)
Tomato Solids	95	.19	25	1.60	62	33	-	Fannin (1982)
Whey Milk & Cheese	72-77	.12 (2)		7.21-8.01 (3)	-	97-98 (4)	-	Price (1981)
Meat Packing		. 197 (5)	. 53	7.16 (6)	-	96 (7)	-	Stafford (1980)
Slaughterhouse	-	075 (5)	14	8.00	81	93 1 (7)	-	Stafford (1980)
Seware Sludge	-		16	9 77	78	-	•	Stafford (1980)
Municipal Garb	age -	-	12	10,09	62	-		Stafford (1980)

Table 2-2. Digester Performance Characteristics

(1) Methane yield as cft/lb Live Weight added

(2) Loading as 1b COD/cft day

(3) Methane yield as cft/lb COD added

(4) COD reduced

(5) Loading as 1b BOD/ft³ day (6) Methane yield as ft^3 /lb BOD added

(7) BOD reduced

(8) Productivity as volume methane produced per volume of reator per day

VS - Volatile Solids TS - Total Solids

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Landfill and Location	Depth <u>(ft)</u>	Area <u>(acres)</u>	MSW In Place <u>(tons)</u>	No. of Gas Wells	Depth of Wells <u>(ft)</u>	LFG Recovered <u>(scf/day)</u>	Heat Content <u>(Btu/scf)</u>
Azusa, CA	170	74	7,000,000	41	100-160	4,240,000	500
Palos Verdes, CA	150-250	42	20,000,000	12	150	1,800,000	720
Cinnaminson Newark, NJ	60	62	2,500,000	29	50-60	700,000	550-600
Fresh Kills Staten Island, NY	50	400	75,000,000	123	55	5,000,000	700
Chicago, IL	128	296	7,000,000	14	128	3,531,000	707
Louisville, KY	46	-	900,000	30	-	700,000	354
Royalton Road, OH	40-120	74	2,000,000	20	40-80	1,400,000	354
Aikin Co., SC	33	40	-	-	-	700,000	-
Houston, TX	62	297		-		7,700,000	-
Richmond, VA	39-118	99	1,500,000	30	59	7,000,000	-

.

Table 2-3. Landfill Performance Characteristics

Sources: Pohland and Harper (1987a) and GRCDA (1983)

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Table 2-4. Trace Constituents Detected in Landfill Gas

Constituent	Mountain View, CA (grains/100scf)*	Scholl Canyon, CA (grains/100scf)*
Hydrogen Sulfide	0.40-0.91	<0.01
Mercaptan Sulfur	0.00-0.33	0.01**
Sulfides (as S ₂)	0.41-0.80	
Residuals	0.93-1.65	-
Acetic Acid	-	0.27
Propionic Acid	-	0.41
Butyric Acid		0.39
Valeric Acid	•	0.13
Caproic Acid		0.08
Water Vapor	•	. 3.0

* grain/100scf = .00034 lb/scf

** Reported as organic sulfur compounds

Source: EMCON 1980

Benzene Bimethylbenzene Butycyclohexane Chlorobenzene Cycloheptane Cyclohexyl-eicosane Decahydroaphthalene Decane Dichloroethane Dichloroethylene Dichlorofluoromethane Dichloromethane Diethylcyclohexane Dimethylcyclohexane Dimethylcyclopentane Dimethylheptane Dimethylhexane Dimethylhexene Dimethyl(methylpropyl)cyclohexane Dimethylpentane Ethylbenzene Ethylbutanol Ethylcyclohexane Ethylmethylbutene Ethylmethylcyclohexane Ethylmethylcyclopentane Ethylmethylheptane Ethylpentene Heptane Heptanol Hexadiene Hexane

Source: GRI 1982

Hexene Iso-octane Iso-octanol Isopropylbenzene Methylbenzene Methylcyclopentane Methylene-butanediol Methylheptane Methylhexane Methyl(methylethenyl)-cyclohexene Methylnonene Methylpentane Methylpentylhydroperoxide Methylpropylpentanol Napthalene Nonane Nonyne Octahydromethylpentalene Octane Pentane Propylbenzene Tetrachloroethene Tetrahydrodimethylfuran Tetramethylbutane Tetramethylcyclopentane Tetramethylhexane Tetramethylhexene Tetramethylpentane Trichlorethane Trichloroethylene Trimethylcyclohexane Trimethylcyclopentane

Table 2-6. Factors Affecting Landfill Gas Production

- Nature of Refuse availability of usable substrate; organic material moisture and nutrient contents; presence of potential inhibitors; protection from microbial activity (i.e., encapsulation in bags or containers).
- Moisture Content provides transport phase for organic substrates and nutrients expect increasing CH₄ production rates with increasing moisture up to approximately 60% (40% solids).
- Particle Size particle size reduction by refuse shredding may be expected to increase gas production rates; however, due to the large number of variables involved, studies are contrary and not clearly conclusive.
- Refuse Compaction may impede moisture and gas flow through wastes, but will minimize volume of wastes; studies give conflicting results.
- Buffer Capacity beneficial in accelerating biological stabilization and increasing gas production rates; buffer needed to moderate effects of volatile and other acids; site specific based on leachate analysis.
- Nutrients whether or not nutrient sufficiency exists may be evaluated through leachate analysis; some have found PO₄ to be limiting area needs more study.
- Temperature affects microbial activity within landfill and vice versa; winter time activity is usually slower.
- Gas Extraction should not exceed biological production; if so, this may lead to excessive amounts of N_2 and O_2 ; O_2 is toxic to the anaerobic process and excess N_2 decreases the energy value and requires expensive gas treatment.

Sources: EMCON (1980) and Pohland and Harper (1987a)

There are several methods available for formulating projections of gas yie from landfills. Theoretical and empirical approaches are reviewed in detail EMCON (1980) and Pohland and Harper (1987a). These are not useful in sizin recovery equipment, but can be used to predict gas yields. The theoretical mode make use of stoichiometric and kinetic methods. Because they fail to inclue numerous factors and assume 100% recovery of gases produced, at best these a rough estimates of potential gas production. Field and laboratory observations a the best indicator of actual gas yields in landfills. Gas yield production ra predictions are generally obtained by comparing the overall gas yields fro laboratory studies to stabilization time, by installing observation wells, or l literature comparison.

CHAPTER 3 BIOGAS COMBUSTION CALCULATIONS

Approximate Fuel Value

Pure methane at standard temperature and pressure has a lower heating value of approximately 912 Btu/ft³. Typical biogas of 65% methane has a heating value of approximately 600 Btu/ft³ since only the methane portion will burn. Approximate equivalents of biogas to other fuels are presented in Table 3-1.

Table 3-1. Fuel Equivalents of Biogas (per 1000 ft³)*

600 ft³ of natural gas 6.6 gal. of propane 5.9 gal. of butane 4.7 gal. of gasoline 4.3 gal. of #2 fuel oil 44 lb. of bituminous coal 100 lb. of medium-dry wood

* Biogas with 65% methane

Source: Palmer 1981

Properties of Gases

The physical and chemical properties of biogas affect the choice of technology used for clean-up and combustion; therefore, a knowledge of these properties is useful for optimizing biogas utilization. Since biogas contains primarily methane and carbon dioxide (see Chapter 2), this discussion is focused on their respective physical characteristics, as listed in Table 3-2. Other components (nitrogen, hydrogen sulfide, trace organics) are present in relatively small quantities, the magnitude of which varies greatly and depends on the composition of the material digested. Although the small concentration of these trace gases have little effect on the physical properties of the gas, they influence the choice of technologies. Therefore, individual components should be evaluated on a site-specific basis.

Table 3-2. Physical Constants of Methane and Carbon Dioxide^a

	Methane (CH ₄)	Carbon Dioxide (CO ₂)
Molecular Weight	16.04	44.01
Specific Gravity, Air=1 ^c	0.554	1.52
Boiling Point @ 14.7 psia	259.0°F	109.4°F ^b
Freezing Point @ 14.7 psia	-296.6°F	-69.9F
Specific Volume	24.2 ft ³ /lb	8.8 ft ³ /lb
Critical Temperature	116.0°F	88.0°F
Critical Pressure	673 psia	1.072 psia
Heat Capacity C. 1 atm	0.540 Btu/lb-°F	0.205 Btu/lb-°F
Ratio C./C.	1.307	1.303
Heat of Combustion	1012 Btu/ft ³	
	23.875 Btu/lb	
Limit of Inflammability	5-15% by volume	
Stoichiometry in Air ^c	0.0947 by volume	
	0.0581 by mass	

a - Properties of pure gases given at 77°F and atmospheric pressure b - Sublimes c - Air at 14.7 psia, 60°F

Volumetric Compensation

Volumetric measurement of biogas, like any gas, must be compensated fo pressure and temperature differences. The equation below (Salisbury 1950 illustrates a simple method of gas volume compensation for a saturated gas:

$$V_s (sat.) = V \times 17.626 \times (H - A)$$

(459.6 + T)

Where:

V = observed volume V_g = volume at standard conditions, 60°F and 30 inches Hg H = absolute gas pressure, inches Hg A = water vapor pressure, inches Hg, for gas at temperature T T = temperature of gas, °F

Flame Velocities

A major consideration in analyzing gaseous fuels, particularly those such as biogas with low energy contents due to dilution with various non-combustible gases is the flame velocity-of that fuel during combustion. Flame velocity is defined as the speed at which a flame progresses into a mixture relative to the speed of the fuel mixture. It is important in the design of systems for feeding fuel and air to burners and in the setting of the spark advance for internal combustion engines. The impact of carbon dioxide concentrations on flame velocities over the limits of inflammability of a methane/carbon dioxide mixture are illustrated in Figure 3-1 The information can be used to compare the performance of a combustion system designed for natural gas that will be modified for operation on biogas. The data were computed using techniques outlined in Salisbury (1950).





Flammability Limits

Flammability limits (or limits of inflammability) indicate the maximum and minimum percentages of a fuel in a fuel and air mixture at which the mixture will burn. This is a critical parameter in biogas combustion due to the dilution of methane in a biogas fuel with carbon dioxide and other inert gases. The flammability limits of methane are listed in Table 3-1, and range from 5% to 15% in air. These two values are also known as the lower explosive limit (LEL) and upper explosive limit (UEL), respectively. The impact of CH_4 dilution (by CO_2 and water vapor) on flammability limits are illustrated in Figure 3-2. The data were computed using techniques in Salisbury (1950).

Figure 3-2. Flammability Limits as a Function of Carbon Dioxide and Water Vapor Concentration



Flame Temperatures

The temperature of the flame front created by a combustible mixture i important with respect to the performance of all types of combustion systems. In the operation of boilers, flame temperature (sometimes referred to as hot mix temperature) is an indication of thermal efficiency. The temperature of the exhaus gases from a combustion system will affect the potential for heat recovery and the formation of nitrogen oxides in the exhaust. The theoretical flame temperature of methane in a stoichiometric mixture with air and including dissociation is 3484°F (North American Mfg. 1978). However, the theoretical flame temperature decreases as the concentration of non-combustibles increases; accordingly, the theoretical flame temperature as a function of water vapor and methane content is shown in Figure 3-3. The data were computed using techniques in Salisbury (1950).





Fuel Energy Value

The gross and net heating values of simple fuels are important in defining the energy available from different gases and are compared in Table 3-3. Since different gases have different heating values, calculation of the net heating value of a mixture such as biogas must take into account not only the amount of methane but also all other combustible and non-combustible gases. The higher heating value (HHV) is the energy released from a given mass of a fuel where the energy required to vaporize the water in the fuel is recovered. The HHV of methane, the primary combustible in biogas, is listed as 1012 Btu/SCF. The lower heating value (LHV) is defined as the higher heating value less the energy required for the vaporization of water in the fuel and combustion products. For methane, the net or lower heating value is 912 Btu/SCF. The effect of biogas moisture content and CH₄ content on the net heating value of biogas is illustrated in Figure 3-4. The data were computed using techniques in Salisbury (1950). A comparison of energy values for several commercial fuels is provided in Table 3-4.

Table 3-3. Comparative Fuel Values for Several Simple Fuels

Heating Values

Btu/ft³ Btu/lb

			<u>Air-Fuel</u>	<u>Ratio</u>	
<u>Fuel</u>	Higher Hea	ting Values	<u>Vol Air</u>	<u>Wt Air</u>	
	(Lower Heati	ng Values)	Vol Fuel	Wt Fue	
Butane, n-C ₄ H ₁₀	3,271	21,321	31.0	15.50	
Tudaana 17	(3,018)	(19,678)	1 20	94 50	
Hydrogen, H ₂	(275)	(51.623)	2.30	54.50	
Hydrogen Sulfide, H ₂ S	646	7,097	7.15	6.08	
	(595)	(6,537)			
Methane, CH_4	1,012	23,875	9.53	17.20	
Octane, C.H.,	6.260	20.796	****	15.10	
	(5,806)	(19,291)	*		
Propane, C ₃ H ₈	2,524	21,669	23.8	15.70	
	(2,322)	(19,937)			

Source: North American Manufacturing 1978

Table 3-4. Comparison Fuel Values for Commercial Fuels

	<u>Heating Values</u> Btu/lb (Btu/gal)		Air-Fuel Ratio	
Fuel	Higher	Lower	<u>Wt. Air</u> <u>Wt. Fuel</u>	<u>SCF</u> Gal.
Natural Gas	21,830	19,695	15.73	~***
Gasoline	20,190 (123,361)	18,790 (114,807)	14.80	1,183
Dicsel (#2)	18,993 (137,080)	17,855 (128,869)	14.35	1,354
Fuel Oil (#4)	18,884 (143,010)	17,790 (135,013)	13.99	1,388
Propane	21,573 (91,500)	19,886 (84,345)	15.35	851

Source: North American Manufacturing 1978



Fuel Mixtures

As described under flammability limits, methane and air mixtures will combus between 5% and 15% methane in air. The optimum concentration of CH_4 in air often referred to as the stoichiometric mixture (i. e., the concentration at which complete combustion occurs without unused air or fuel) is 9.4%. This is also referred to as the Air-Fuel Ratio, which is defined as:

For methane in air, the stoichiometric AF is 17.21 lb air/ lb CH₄.

Equivalence ratios (ϕ) are used to describe the degree of variation from the stoichiometric ratio, from excess air to excess fuel. The equivalence ratio is defined as:

Equivalence Ratio (ϕ) = <u>AF Stoichiometric</u> AF Actual Where: $\phi = 1$ is a stoichiometric ratio $\phi < 1$ is a lean mixture, excess air $\phi > 1$ is a rich mixture, excess fuel The stoichiometric ratio of biogas will obviously vary with the amount of no combustible gases mixed with the methane. For example, a mixture of 60% metha and 40% carbon dioxide will have the theoretical chemical reaction with air of:

 $CH_4 + 0.67 CO_2 + 2 O_2 + 7.52 N_2 ---> 2 H_2O + 1.67 CO_2 + 7.52 N_2$

and will have a stoichiometric ratio $(\phi=1)$ of 6.03 lb air/lb biogas.

For comparison, the Air-Fuel Ratio of biogas can be defined as (Stahl 1983):

$AF Actual = \frac{m air}{V_{bg} r P_{c}}$)H4	
Where: m air V _{bg} r P _{CH4}	= = =	mass flowrate of intake air flowrate of biogas at standard condition volume ratio of CH_4 in biogas density of methane (See Table 3-1)

This ratio is directly related to the concentration of methane, and can compared to the stoichiometric ratio for air and methane of 17.21 to calcula equivalence ratios. Additional comparative data on combustion characteristics methane and other fuels are illustrated in Tables 3-3 and 3-4, and the variation Air-Fuel Ratio for biogas as a function of the methane and water vapor content a illustrated in Figure 3-5. The data were computed using techniques in Salisbu (1950).

A rule-of-thumb often used by combustion engineers is one cubic foot of air required to produce 100 Btu of heat. North American Mfg. (1978) recommends f gaseous fuels having more than 400 gross Btu/SCF the following empirical formula:

<u>Required Air Volume</u> = gross heating value in Btu/SCF - 0.6 Fuel Gas Volume 100



<u>ater Vapor</u>

While not as prevalent a diluent as carbon dioxide, water vapor can have a gnificant effect on biogas combustion characteristics. As illustrated in Figures 3-through 3-5, water vapor has a small but noticeable impact on flame temperature, ammability limits, lower heating value, and Air-Fuel Ratios of biogas.

These effects plus the potential for corrosion highlight the need for water por reduction in biogas. Depending on temperature, biogas samples immediately ter the outlet from a digester may contain as much as 50 mg/L water vapor, hich is near the saturation level.

oplication of Data

Much of the data presented in this section will be utilized by the engineer aring the design of equipment for biogas systems. The information is needed to etermine the sizing, flow rates, and configuration for equipment specifically esigned for the combustion of biogas. The data can also be used to modify nuipment designed for other fuels such as natural gas and propane for operation on ogas fuels. Many of the systems designed for these conventional fuels can be mply modified for biogas combustion by using the appropriate design factors.
However, as discussed in Chapter 2, the biogas produced from a digester an landfill can change in composition depending on a number of factors. Changes is feed, loading rates, temperature and other factors can significantly affect the composition of the biogas produced. Therefore, a knowledge of the data discusses in this chapter is important to the operator of a biogas utilization system who analyzing problems in the performance of a biogas combustion system.

CHAPTER 4 HANDLING AND COLLECTION OF BIOGAS

Introduction

The systems and equipment required for collection of biogas from an anaerobic system or landfill, and for biogas transport to the combustion equipment, and/or to other pieces of equipment such as compressors, clean-up systems, and storage tanks are discussed in this chapter. Most of this equipment consists of piping and valves but special designs and materials are required for the removal of condensed water and the prevention of corrosion.

Piping Systems

Design and Operating Pressures. The operating pressure of most biogas handling systems will generally be less than 1 psig (30 inches water column, w.c.) However, if the system contains a compressor, some piping in the system could have an operating pressure as high as 500 psig. Most systems will need a relief valve therefore, the maximum operating pressure will be the set pressure of the relief valve. If a system with a compressor does not have a relief valve, the maximum operating pressure will be the shut-off pressure of the compressor which occurs when the gas flow through the compressor is zero and the output pressure is a maximum.

The design pressure used for determination of pipe and valve wall thickness schedules should be computed as follows:

Design Pressure = 1.5 x Maximum Operating Pressure

High pressure systems should be hydrostatically tested to assure that there are no safety problems with the system. The pressure at which the system should be hydrostatically tested is computed as follows:

Hydrostatic Test Pressure = 1.5 x Design Pressure

Design and Operating Temperatures. The temperature of the biogas will be approximately the same as the temperature of the source from which the gas is produced, i. e., digester or landfill. The maximum operating temperature of a biogas handling system will be approximately 150°F since the highest temperature biogas generators known are thermophilic digesters which operate best at a temperature of 131°F. If the gas is compressed without cooling to remove the heat of compression the gas temperature will be significantly increased. The gas temperature can computed as follows:

 $T_{compressor out} = T_{compressor in} \times (P_{out}/P_{in})$

where:

 $T_{compressor out} = Compressor Outlet Gas Temperature (°R),$ $<math>T_{compressor in} = Compressor Inlet Gas Temperature (°R),$ $<math>P_{out} = Compressor Outlet Pressure (psig),$ $P_{in} = Compressor Inlet Pressure (psig), and$ $T^{\circ}R = T^{\circ}F + 460$

The design temperature is computed as follows: Design Temperature = 1.5 x Maximum Operating Temperature

<u>Pipe Sizing</u>. A quick determination of pipe size can be made using the diagram presented in Figure 4-1. In order to use the figure, the rate of gas flo in cubic feet per hour and the length of pipe must be determined. As shown in the figure, a flow rate of 50 cubic feet per hour in a pipe 75 feet long requires a pip diameter of 1/2 inch. Likewise a flow of 80 cubic feet per hour in a 50 foot pip requires a 3/4 inch pipe.





Source: ESCAP 1980

<u>Pipe Thickness Selection</u>. The design pressure and temperature computed in the preceding sections are used to select the pipe thickness. <u>In general</u>, most low pressure systems can use standard weight pipe (Schedule 40), but high pressure systems usually require heavier walls. Carbon steel should be adequate for all low pressure systems but other materials may not. The temperature and pressure rating of any material other than carbon steel, stainless steel, or galvanized iron should be checked, and the pipe should not be used if this information cannot be obtained.

Some materials may be marked with an indication such as ASTM D-124. This indicates that information on the material can be obtained from the American Society for Testing and Materials (ASTM).

The wall thickness needed for high pressure piping depends on several factors such as the design pressure, material, corrosion allowances, and allowances for threaded ends (if used). ANSI B31.1, Code for Pressure Piping, should be used for the determination of the wall thickness of all high pressure piping systems.

<u>Materials</u>. Once the design temperature and pressure of the handling and collection system have been established, the materials for the system can be selected. The advantages and disadvantages of the more common materials used in biogas handling and collection systems are compared in Table 4-2. High pressure systems will require steel or iron pipe, but plastic piping may be preferred for ease of installation with low pressure systems.

<u>Piping Codes</u>. State and local building codes and/or insurance carriers may require that the biogas piping systems be designed in accordance with national codes or standards. Table 4-3 lists the principal codes that may apply to biogas piping systems as published by the American Society for Testing and Materials (ASTM) and the American National Standards Institute (ANSI).

<u>Special Considerations for Pipe Installation</u>. There are other additional considerations which should be incorporated in the design of a piping system.

Accidental Breakage - One of the major dangers with piping systems transporting a combustible gas (particularly plastics) is the susceptibility of the these systems to accidental breakage by plant personnel, vehicles, or animals. Methods of pipe protection include burying pipes in soil and placing heavy steel pipes near plastic piping that could be accidentally broken.

Table 4-1. Advantages and Disadvantages of Materials for Gas Piping

<u>Material</u>	<u>Advantages</u>	Disadvantages
Plastic (PVC, CPVC)	Easy to work with, relatively inexpensive	Subject to breaking, can be eaten by rodents; valves more expensive than galvanized, also subject to ultraviolet degradation
Galvanized Iron	Less breakable	Can rust, pipe more expensive than plastic
Flexible (5 ply rubber hose)	Ease of connection to equipment	Expensive
Plastic (ABS)	None	Not Recommended

Sources: ESCAP 1980 and EMCON 1980

 Table 4-2. National Standards Applicable to Piping Systems

 ANSI B-31, "Piping Codes"

ASTM D-3350, "Polyethylene Plastics Pipe and Fitting Materials"

ASTM D-2774, "Underground Installation of Thermoplastic Pressure Piping"

ASTM D-2321, "Underground Installation of Flexible Thermoplastic Sewer Piping"

ASTM D-2513, "Thermoplastic Gas Pressure Pipe, Tubing and Fittings"

<u>Vibration Isolation</u> - Compressors can potentially transmit vibration loads to plastic pipe or plastic storage vessels, which could eventually damage these components. Vibration dampers may be required to preclude transmission of vibration loads.

<u>Thermal Expansion</u> - Thermal loads could be placed on plastic pipe or storage vessels by steel pipe heated by combustion or compression equipment. Thermal expansion loops or joints may be required to reduce these loads and prevent damage to equipment.

<u>Valves</u>

A summary of the advantages and disadvantages of the different types of valves that can be used in biogas systems is presented in Table 4-3. Valve materia selection is subject to the same restrictions as piping systems. Brass ball valve (brass taps) can be used; but, these must not contain any lead as hydrogen sulfic tends to attack the lead and destroy the tap.

Painting [Value]

All metallic piping should be painted to prevent rust or corrosion. Paintin should be accomplished regardless of whether or not the pipe is indoors, outdoor or buried. Table 4-4 contains some recommendations on paint for biogas handlin and collection equipment.

Condensate Drains

One of the major problems associated with handling biogas is the larg quantity of water vapor contained in the gas. In order to remove water from th pipe, all horizontal runs of pipe should be installed with a pipe slope of 1:100. condensate drain must be located at all low points in the piping.

There are a number of different systems which can be used for drainin condensate from a pipe. Figures 4-2 through 4-5 illustrate a manual system (tee), U-pipe drain, a siphon system, and a water outlet device. The main advantages an disadvantages of each system are listed in Table 4-6.

Table 4-3. Advantages and Disadvantages of Valves for Biogas Systems

Type	<u>Advantages</u>	Disadvantages
Gate	Low Cost	Moisture can be trapped in slot
Globe	Slightly higher cost than gate	Not good for quick shut-off
Butterfly	Low cost	Not recommended for combustible gas service
Ball	Best choice for shut-off	Cost

Source: ESCAP 1980

Table 4-4. Recommendations for Painting

Cost	Primer <u>Type</u>	Number of Coats	Paint <u>Type</u>	Number of Coats
Low	Red Oxide	1	Normal	2
Medium	Anti-saline	1	High-Build Black Bitumen	2
High	Epoxy	1	*Ероху	2

* Steel must be sand- or grit-blasted.

Source: ESCAP 1980

Table 4-5. Condensate Draining Systems

Type	Advantages	<u>Disadvantages</u>
Tee	Inexpensive, no danger of flooding if checked	Manual attention required
U-pipe Design	Automatic	Danger of gas leak in the event of evaporation
Siphon and block gas line if underground	Automatic	Expensive, can flood
Water Outlet Device Source: ESCAP 1980	Automatic	Expensive

Figure 4-2. Manual Condensate Drain



Source: ESCAP 1980





Source: ESCAP 1980





Source: ESCAP 1980





Source: ESCAP 1980

Flame Arresters

A flame arrestor should be located in the gas line just downstream of the gas source. The purpose of this device is to prevent a flame from running back down the pipe and causing an explosion. A ball or roll of fine mesh copper wire works well for this application. Two typical flame arrestor installations are shown in Figures 4-6 and 4-7.





Source: ESCAP 1980

Figure 4-7. Flame Arrestor Installation B



Source: ESCAP 1980

Leak Checks

The entire piping system should be pressure tested for leaks. The method is checking for leaks depends on the pressure at which the system will operate. His pressure systems can be checked for leaks during hydrostatic testing. Low pressu systems can be checked using a simple pressurization system such as the of illustrated in Figure 4-8. The elevation level between the top and the water in the bucket and the top of the water level in the U-tube should be equal to the desi pressure of the system. If the water level in the bucket remains constant for hours, the system can be considered "leak free." If the water level drops, the le can be found by brushing or squirting soapy water on joints and other connection until bubbles identify the source of the leak.



Figure 4-8. Leak Test Pressurization System

Collection from Digesters

Biogas is typically extracted from digesters with a pipe inserted in the ga space. The pipe may be vertically or horizontally aligned. Care must be taken to insure that the pipe is not blocked by the material being digested, by any scum o foam layers at the top, or by the collapse of a flexible cover.

Collection from Landfills

The most common system for extraction of biogas from a landfill is the induced well system. The system uses a compressor to pull the gas from the decomposing material and through a piping network. A typical vertical pipe landfill extraction system is illustrated in Figure 4-9. A series of vertical wells with perforated pipe inserted in these wells is used for gas removal. The wells are spaced such that the radii of influence overlap and the pipes are inserted below the refuse level. The lower portion of the pipe is perforated, and the insertion hole is backfilled after insertion to prevent air infiltration. Horizontal trenches can be used to remove gas, but these tend to be more difficult to operate without undue air leakage or air intrusion (USEPA 1979a).





Source: USEPA 1979a

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CHAPTER 5 BIOGAS CLEAN-UP

Treatment of Blogas

The equipment selected for the treatment of biogas will depend upon the intended use of the gas. Product gases may be withdrawn from treatment system and landfills and simply flared to prevent migration and environmental impact Alternatively, the gas can be withdrawn and sold to a consumer directly, used on site with or without prior treatment, or treated and sold to a consumer as pipeline gas.

The type and extent of treatment needed depends on the composition of the gas. As seen in previous chapters, raw biogas typically has a relatively low heating value due to dilution of methane with CO_2 , N_2 , and possibly O_2 . Biogas also ofter contains water and hydrogen sulfide, which can be corrosive. In some cases, trace levels of hydrocarbons are also present (particularly in landfill gases) and may be of some concern with respect to migration and environmental impact, but these compounds may be expected to oxidize rapidly and be of minimal concern if the gas is burned (except in internal combustion engines). Therefore, the primary objectives of gas treatment are either the removal of corrosive constituents (hydrogen sulfide and water), or those which dilute methane and affect the volumetric heating value (carbon dioxide and nitrogen), or both.

Accordingly, there are a number of treatment processes available for removing water, hydrogen sulfide, carbon dioxide, and nitrogen either singularly or in combination. These have been carefully reviewed by Jones and Perry (1976), USEPA (1979a), Ashare (1981), Love (1983), and EMCON (1983). These are summarized and reviewed in the remainder of this section. The gases produced by such treatment systems may be classified on the basis of heating value as either medium BTU (500-600 Btu/SCF) or high BTU (600-1000 Btu/SCF) gases.

Medium BTU Gases

Medium BTU gases are useful for process heating and for driving internal combustion engines. They are generally produced from raw biogas by removing water vapor and/or hydrogen sulfide, with nitrogen and carbon dioxide remaining untreated.

Hvdrogen Sulfide Removal

As indicated in Figure 5-1, hydrogen sulfide can be removed using a variety liquid absorbents and/or solid phase oxidants. Hydrogen sulfide can be selective removed with a few of the aqueous processes, but most of these also remove carbo dioxide which is unnecessary for some applications. Therefore, the so-called d processes are preferred for medium BTU applications, where CO_2 removal is n necessary, and are also more economical on the scale of most biogas-producin processes.

Aqueous Absorption Processes. Hydrogen sulfide can be somewhat selective absorbed in a variety of aqueous solutions. To accomplish this, the biogas is blow through a scrubbing tower (Figure 5-2) equipped with fixed trays, baffles, or som other packing material which provides a high surface area and small fil thicknesses. Aqueous solutions which can be used to remove H_2S are listed in Tab 5-1, and include an assortment of sodium or potassium carbonates, ammonia, glycols in combination with various intermediate oxygen carriers and corrosic inhibitors.

Table 5-1. Aqueous Solutions Used To Remove Hydrogen Sulfide From Bio

Process Name	Aqueous Medium
Ferrox	Sodium carbonate with ferric hydroxide
Giammarco-Vetrocoke	Sodium or potassium carbonate with arsenic
Stretford	Sodium carbonate with sodium vanadate and anthr quinone disulfonic acid
Takahax	Sodium carbonate with naphthaquinone
Townsend	Ethylene glycol with sulfur dioxide
Purox	Ammonia with hydroquinone

The Ferrox process uses a solution of sodium carbonate and ferric hydroxid while the Giammarco-Vetrocoke process uses sodium or potassium carbonates i combination with arsenic compounds to absorb hydrogen sulfide. The Stretfor process uses sodium carbonate to convert hydrogen sulfide to sodium bisulfid which is then converted to elemental sulfur with sodium vanadate and sodium sal of anthraquinone and disulfonic acid. The Takahax process uses naphthaquinone in solution of sodium carbonate. The Purox process also uses quinones, dissolved in a





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Figure 5-2. Simple Biogas Purification Arrangement



Source: Probstein 1982

solution of ammonia, to absorb sulfide. The Townsend process uses a concentrate solution of di- or triethylene glycol in combination with sulfur dioxide.

For very large systems with gas flow rates in excess of 10^6 ft³/day, the solutions indicated above can be regenerated, and sulfur recovered for industria use. Absorption is initially carried out at low temperatures and high pressures where sulfide solubilities are highest, and regeneration of the absorbent is most typically accomplished by heating the solution to decrease solubility and release concentrated gas. Sulfur may then be recovered from the concentrated gas by the Claus process, wherein part of the sulfide is burned to form elemental sulfur an sulfur dioxide and the remaining sulfide is catalytically converted to elemental sulfur in the presence of aluminum oxide.

Most of these chemical solutions are expensive, and the treatment systems ar also capital intensive. Therefore, these systems are more feasible for large scal biogas recovery projects. For smaller scale systems, dry adsorption is the mor feasible option and is described in the next section.

Drv Adsorption Processes For small scale biogas producers, an alternative t the wet absorption systems described above is dry adsorption, or chemisorption Several dry processes are available, using particles of either activated carbon molecular sieve, or iron sponge to remove sulfide from the gas phase to the solid phase. These are sometimes referred to as dry oxidation processes because elemental sulfur or oxides of sulfur are produced (and can be recovered) during oxidative regeneration of the catalyst.

Activated carbon adsorbs and oxidizes sulfide to elemental sulfur. Activated carbon has a very high surface area (4,400 to 5,300 in² per ounce), a wide variety of pore sizes, and a slightly charged nature which attracts both inorganic and organic compounds. The carbon is loaded into two or more sequential pressure vessels and the gas pumped through the packed beds. As the surface area of the carbon becomes saturated with sulfur, the acid gas begins to appear in the gaseous effluent, and indicates that one of the vessels needs to be recharged or regenerated. Activated carbon is typically regenerated with steam, at temperatures up to 750 °F. Activated carbon is widely available from a large assortment of commercial manufacturers.

<u>Molecular sieves</u> can be used to remove hydrogen sulfide, mercaptans, water and a number of other impurities. Molecular sieves consist of activated alumina of silica compounds which have a high affinity for polar molecules. They provide surface areas up to 1,300 in² per ounce and have well-defined pore sizes which allow for selective removal of different compounds. Regeneration of the surface areas on saturated materials is accomplished by passing a heated gas (400 to 600°F) through the reactor bed. Molecular sieves are best suited to selective water and sulfur removal on a small to medium scale.

The <u>iron sponge</u> process uses coated pellets or wood shavings impregnated with ferric oxide to chemically bind sulfur to iron. The amount of sulfur which can be removed is stoichiometrically linked to the amount of iron provided. System design is based on the concentration of sulfide in the gas and the bulk density of the sponge material.

In the removal (scrubbing) process, hydrogen sulfide reacts with ferric oxide impregnated in wood shavings to form ferric sulfide and water. The gas is pumped through a sponge bed similar in construction to an activated carbon or molecular sieve reactor, where the iron sponge is supported on screens or trays in a cylindrical or rectangular tower. The linear gas velocity is kept below 10 ft/min to assure adequate reaction time and contact opportunity. The process may be operated at pressures ranging from ambient to several hundred psig. Efficient operation can

be achieved at ambient temperature or warmer, but the moisture content of the sponge should be maintained between 30 and 60%. Operation at pH 8.0 to 8.5 best, and pH should never drop below 7.5.

In the regeneration stage, oxygen is added to convert the ferric sulfide a ferric oxide and elemental sulfur. This can be accomplished by removing the spong and exposing it to air by spreading it out in thin layers and periodically turning is The sponge can also be recharged in the reactor by bleeding in oxygen. Howeve this process must be carefully controlled because the regeneration reaction exothermic. The catalyst may be poisoned with hydrocarbons above 120 °F, there fore, oxygen feed rates should be controlled to keep the vessel temperature belo this value. Scrubbing and regeneration can take place at the same time by bleedin oxygen into the feed gas and maintaining temperature at a prespecified level.

Sponge materials can be regenerated 3 to 5 times, depending on the amount of sulfur removed and the care exercised in maintaining appropriate temperatures, pF and moisture content. The sponge will eventually become oversaturated wit elemental sulfur, but shorter lifetimes are caused by destroying the inert support material with acid and heat, or by catalyst poisoning. In general, 50 to 60% of the original weight of the sponge can be adsorbed as elemental sulfur.

The sizing of an iron sponge system is illustrated in Table 5-2. Th calculations are based on an iron sponge bulk density of 15 pounds per cubic foo and a linear gas velocity of 10 ft per minute.

High BTU Gases

High BTU gases of pipeline quality can be produced by removing sulfide carbon dioxide, and water vapor. This can be accomplished with aqueous scrubber operated over a wide range of temperatures and pressures, depending on the natur of the solvation or chemical equilibrium responsible for acid gas removal. Otherwise semipermeable membranes are available to selectively remove specific gases in hig pressure reverse osmosis processes.

<u>Carbon dioxide and Hydrogen Sulfide removal</u>. In addition to those aqueou absorbents described for hydrogen sulfide removal in the previous section, there ar many chemical solutions commercially available which can be used to remove carbo dioxide and hydrogen sulfide concurrently. These are listed in Table 5-3 with th operating conditions and the advantages and disadvantages of each process.

Table 5-2. Design Example for a Small Scale Iron Sponge Process

Design Basis:

5000 scf/day 0.3 grains H₂S/scf (30 grains/100 scf)

Sulfur Produced:

5000 scf/day x 0.94 lb S/lb H_2S x 0.3 grains/scf x 1 lb/7000 grains = 0.20 lbs sulfur/day

Iron Sponge Required:

0.20 lbs sulfur x 2.0 lb FeO_3 /lb sulfur x safety factor (1.5) = 0.6 lb iron oxide/day or 220 lb/year

Reactor Volume:

0.6 lb iron oxide/day x 1.0 ft⁸ iron sponge/15.0 lb iron oxide = 0.04 ft⁸ reactor/day or 15 ft⁸/year (110 gallons)

Reactor Dimensions:

volume = 15 ft³ = height x flow area flow velocity = 2 ft/min = flowrate/flow area

height = 9 ft (maximum)

area = volume/height = $15 \text{ ft}^3/9 \text{ ft} = 1.67 \text{ ft}^2$

diameter = sqrt(4 x area/ Pi) = 1.5 ft

In general, these processes employ either solvation solutions where the objective is to dissolve CO_2 and H_2S in the liquid, or solutions which reac chemically to alter the ionic character of these gases and, therefore, also drive them into solution. Solutions of the former category include the <u>Solvents</u> and the latter include the <u>Alkanolamines</u> and <u>Alkaline Salts</u> detailed in Table 5-3.

The <u>Solvent</u> processes are typically operated at low temperatures, since the solubilities of CO_2 and H_2S both increase with decreasing temperature. These processes are also operated at high pressure, since solubility is a function of the partial pressure of the gas being dissolved.

Table 5-3. Liquid Absorption Processes for CO₂ and H₂S Removal

Gas Treatment <u>Process</u>	Absorbent :	Operating Temperature	Operating <u>Pressure</u>	Method of <u>Regeneration</u>	λα: <u>CO2</u>	id Ga <u>H2S</u>	ses Removed <u>Mercaptans</u>	Supplier(s)	Advantages	Disadvantage
<u>Wet Srubber</u>	Water	41 to 50 ⁰ F	>200 psig	High Temp Low Pressure	Yes	Yes	Yes	-	Low solvent cost, no nitrogenous vapors	Low efficiend
<u>Alkanolamihes</u> Amine-guard	Hono- ethanolamine (HEA)	up to 120°F	High	Reboiling Low pressure	Yes	Yes	-	AmineGuard	High efficiency, moderate solvent cost	Bigh capita cost, corrosi inhibitors toxic, foami agents neede
SNPA-D ea	Diethano- lamine (DEA)	up to 120 ⁰ F	>500 psig	Heating Low pressure	Yes	Yes		Ralph M. Parsons, Fluor Engineers	High efficiency noncorrosive & nonfoaming	High capita and solvent costs
Econamine	Hydroxy- amino ethylester (DGA)	up to 120 °F	>500 peig	Heating Low pressure	¥•s	¥#5	-	Fluor Engineers	Moderate capital and operating costs	High solven cost, corrosi inhibitors needed
<u>Alkaline Salts</u>										
Benfield	Potassium carbonate	240 ⁰ f 10	0 to 2000 pm	ig Steam	¥өж	Yøs	-	Benfield	Low solvent cost, high efficiency	High capita cost, corrosi inhibitors nee Foaming agen needed
Catscarb C	Potassium arbonate plu amine borate	60 to 8 450 ⁰ 7	100 to 1000 psig	Stean	Yes	Yes	~	Eickmeyør 6 associates	Low solvent cost, high efficiency Non toxic addatives	High capita cost, corrosi inhibitors (Foaming agen needed
Gianmarco- Vetrocoke	Potassium plus arsenic trioxide or glycine	120 to 250°F	0 to 1100 psig	Steam or boiling	Yes	Yes	Yes	Gianmarco -Vetrocoke	Low solvent cost, high efficiency	High capita cost, corrosi inhibitors a foaming agen needad

Table 5-3. Liquid Absorption Processes for CO₂ and H₂S Removal (con't)

Gas Treatmer <u>Process</u>	it <u>Absorbent</u> T	Operating Emperature	Operating <u>Pressure</u>	Method of <u>Regeneration</u>	<u>Ac:</u> <u>CO2</u>	ld Gas H2S B	es Removed Iercaptans	Supplier(s)	Advantages	Disadvanta
Alkaline Salt	<u>s (Con't)</u>									
Alkazid-N am	Potassium salt of methyl ino propionic a	- cid	-	-	Yes	Yes	Yes	I.G. Farber Industries	-	**
Alkazid-DIN C	Potassium salt of methyl or dimethylamine acetic acid	- 0-	-	-	Yes	Yes	Yes	I. G. Farber Industries	-	-
Alkazid-S	Sodium phenolate	-	-	-	Yes	Yes	Yes	I. G. Farber Industries	-	-
Solvente										
Sulfinol d	Tetrahydro- thiophene dioxide plus ii¢opropanolami	Ambient ne	0 to 1000 psig	Reboiling or flashing at low temperature	Ye	s Yes	Yes	Shell Co. Development	Noderate capitai and chemical cost, flexible, low corrosion	-
Selexoĺ	Dimethyl ether of poly- ethlyene glycol	-10 ^O F to ambient	>300 psig	Low Pressure	χe	5 Yea	Yes	Allied Chemical	High efficiency Selective for H ₂ S, non corrosive and nontoxic	High capi and chemi costs
Fluor	Anhydrous propylene carbonate	-50 ⁰ F	>300 psig	Low pressure	Ye	s Yes	Yes	Fluor Engineers	High efficiency Non corrosive and nontoxic	High capi and chemic costs
Purisol	N-methyl pyrrolidone	Low	High	High temp	NO	Yes	-	Lurgi Kohle	High efficiency	High capi cost
Rectisol	Nethanol	S to	High	High temp low pressure	Yes	Yes	Yes	Largi Mineral- oeltechnick Union Carbid	High efficiency low chemical cost e	High capi and solve loss
Amisol	Activated carbon surface area	Ambient	Ambient	Low pressure steam	-	-	-	-	<u>_</u>	-

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The <u>Alkanolamines</u> are typically operated as warm processes, since heat help the chemical reaction. However, excessive heat can cause vaporization and loss of the chemical solution. Therefore, these processes are usually operated at ambient temperatures (up to 120 °F). These chemicals are somewhat corrosive, and ant corrosion agents are usually needed.

Alkanolamine absorption methods have a widespread acceptance for CC removal from natural gas. Monoethanol (MEA), diethanolamines (DEA), and diglycolamine (DGA) have also been successfully applied. MEA is corrosive at 19 concentrations, whereas, DEA may be used at solution strengths approaching 35 without undue corrosion. DGA is even less corrosive and is also nonfoamin Therefore, DEA, which does not absorb heavy hydrocarbons and, therefor selectively removes CO_2 , and DGA are generally preferred.

The <u>Alkaline Salts</u> are operated at very high temperatures (up to 450 °F) and very high pressures (up to 2000 psig). These solutions, like the <u>Alkanolamines</u>, and corrosive and require the addition of corrosion inhibitors if steel tanks are used. These solutions also usually employ a chemical activating agent and have a tendence to foam, therefore, anti-foaming agents are often included in the treatment strategy. The activating agents are proprietary, and in at least one case (Giammaro Vetrocoke), toxic and undesirable.

Another method of removing CO_2 and H_2S is using <u>Semipermeable Membran</u> <u>Processes</u> (reverse osmosis). Commercial processes are available from General Electric and Monsanto. In these systems, organic polymer membranes in one of several configurations (spiral wound, tubular, and hollow fiber) are used to "filter carbon dioxide out of the gas stream. Under relatively high pressures ranging from 150 to 2000 psig and temperatures below 120°F, CO_2 is chemically bound to the membrane surfaces and migrates by diffusion through the membrane.

The membrane materials are specially formulated to selectively separate carbo dioxide from methane. The permeability of the membrane is a direct function of th chemical solubility of the target compound in the membrane. To separate tw compounds such as CO_2 and CH_4 , one gas must have a high solubility in th membrane while the other is insoluble. Accordingly, rejection (separation) efficiencies are typically quite high when the systems are operated as designed.

However, the membranes used are rather fragile by construction, and wit extremely small pores, require a particulate-free input gas. However, variations i input composition do not result in wide variations in gaseous components such a hydrogen sulfide, and mercaptans does not greatly affect separation efficiencies These systems are very capital intensive and not well suited to small scale applications.

<u>Dehydration</u>. Many of the Alkanolamine solutions also remove a large percentage of the water vapor in biogas. However, if a dry oxidation process such as iron sponge is used (this operates best with an iron oxide moisture content of 30 to 60%), further water vapor removal may be needed.

For large scale applications, the gas is typically compressed and cooled prior to being dehydrated by absorption with glycol or triethylene glycol. As indicated in Table 5-4, silica gel, alumina, or molecular sieves are also acceptable alternatives for adsorbing excess water vapor, although these techniques can be prohibitively expensive for large applications and are typically the preferred alternatives for small scale operations.

<u>Nitrogen Removal</u>. Nitrogen may be removed by liquefying the methane fraction of biogas by mechanical refrigeration, leaving the other gas fractions to be exhausted. Considerable refrigeration equipment is required for this process and it is usually prohibitively costly. The best practice is to avoid drawing air into the treatment system to the greatest extent possible, thereby minimizing the nitrogen content.

Economics of Biogas Treatment

The economics of implementing the preceding gas collection and treatment alternatives have been reviewed in detail by others (Ashare 1981, USEPA 1979a). In the EPA study, four gas treatment alternatives were considered, including dehydration, dehydration plus CO_2 removal, dehydration plus CO_2 and N_2 removal, and dehydration plus CO_2 removal and propane blending.

Each alternative was analyzed at several gas production rates, as summarized in Table 5-5. These data illustrate the high costs of carbon dioxide and nitrogen removal and underscore the importance of minimizing the introduction of air during gas extraction from landfill projects. Based upon an energy value equivalent to revenue of \$2 per million Btu (1979 dollars), the probable payback periods associated with each alternative ranged from <3 years (Alternative I) to 10 to 30 years (Alternatives II.and IV) and >30 years (Alternative III).

Ashare (1981) presented a slightly more recent summary of the costs of several commercially available systems, as reproduced in Table 5-6. Costs were presented for

Table 5-4.Summary of Gas Treatment Methods Available for the
Removal of Water, Hydrocarbons, and Carbon Dioxide

<u>Compound</u>	Process <u>Type</u>	Proce <u>Avai</u>	ss Alternatives lable
Water	Adsorption	1. Silica 2. Molec 3. Alumi	Gel ular sieves, and ina
	Absorption	1. Ethylo tempe 2. Selexe	ene glycol (at low rature -20°F) ol
	Refrigeration	1. Chilli	ng to -4°F
Hydrocarbons	Adsorption	I. Activ	ated carbon
	Absorption	1. Lean 2. Ethyle 3. Selexc all at (-20°F	oil absorption, ene glycol, and bl low temperatures
	Combination	1. Refri Ethyl activa adsor	geration with ene glycol plus ited carbon ption
CO_2 and H_2S	Absorption	1. Organ Selexo Fluor	ic Solvents bl
		Rectis 2. Alkal Hot p hibite (Benf	sol ine Salt Solutions otassium and In- id hot potassium ield and Catacarb
	· .	3. Alkar mon uCAl chemi	sses) iolamines o,-di-tri-ethano s; diglycolamines; RSOL-CR (proprietary ical)
	Adsorption	1. Molec	ular Sieves
	Membrane Separation	1. Hollo	w Fiber Membrane

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<u>Treatment Alternative</u>	Cost <u>Item</u>	<u>Product</u>	i <u>on Rate, s</u>	cf/min
Alternative I.	_			
Dehydration, compression	Input	485	1,225	2,450
	Output	460	1,160	2,320
Capital Cost,	10 ⁶ \$	636	957	1,388
Annual Opera	ating Cost, 10 ⁶ \$	185	273	387
Annual Energ	39 Output, 10 ⁹ Btu	109	273	484
Energy Cost,	\$/10 ⁶ Btu	1.7	1.0	0.8
Alternative II. Dehydration and C0 ₂ removal	Input Output	1,670 485	2,276 959	5,000 1,495
Capital Cost,	10 ⁶ \$	1,740	2,772	3,792
Annual Opera	ating Cost, 10 ⁶ \$	359	537	702
Annual Energy	39 Output, 10 ⁹ Btu	212	413	587
Energy Cost,	\$/10 ⁶ Btu	1.7	1.3	1.3
Alternative III. Dehydration plus C0 ₂ removal and N ₂ removal	Input Output	1,670 420	3,335 870	5,000 1,425
Capital Cost,	10 ⁶ \$	2,612	4,038	5,450
Annual Opera	ting Cost, 10 ⁶ \$	555	807	1,051
Annual Energ	y Output, 10 ⁹ Btu	198	404	657
Energy Cost,	\$/10 ⁶ Btu	2.0	2.0	1.6
Alternative IV. Dehydration plus CO ₂ removal and propane blending	Input Output	1,670 502	3,335 1,004	5,000 1,543
Capital Cost,	10 ⁶ \$	1,802	2,847	3,877
Annual Opera	ting Cost, 10 ⁶ \$	463	730	992
Annual Energ	y Output 10 ⁹ Btu	244	456	709
Energy Cost, S	5/10 ⁶	1.9	1.6	1.4

Source: USEPA 1979a

several medium-to-large scale systems, with gas processing rates of 3.6 MM SCF/I 36 MM SCF/D, and 108 MM SCF/D. These systems are on the large end of th biogas scale, and are probably only meaningful for large landfill gas recover projects. Obviously, these costs are not bearable for small systems, and it is unwis to project cost for systems two orders of magnitude or smaller.

Moreover, the degree of treatment provided by these systems is only require for pipeline gas production. For most on-site uses, these systems are no recommended. Especially on the farm, it is more advisable to use more rudimentar systems such as the iron sponge for sulfide control, and adapt to the lower heatin value (i.e., do not attempt to remove carbon dioxide). Iron sponge treatment system can be purchased from commercial manufacturers or be home-made relativel inexpensively. As an alternate, it may be more economical to pay the higher maintenance costs resulting from corrosion, or purchase corrosion resistant equipment and avoid cleaning the gas altogether.

Table 5-6. Summary of Capital and Operating Costs For Some Commercial Gas Treatment Systems

Commercial Process	<u>3.6 M</u> Capital Cost (Thousa	<u>M SCF/D</u> Operating Cost nds of \$)	<u>36 MM SCF/D</u> Capital Operating Cost Cost (Thousands of \$)		<u>108 M</u> Capital Cost (Thousa	<u>M SCF/D</u> Operating Cost ands of \$)
Selexol			1,195	224	2,321	489
Amine-Guard	358	40	915	271	1,802	645
Benfield			777	194	1,601	426
Catacarb	283	30	893	226	1,727	513
Membrane	97	<u>21</u>	432	128	921	253
Source: Ashard	: 1981					

CHAPTER 6 COMPRESSION OF BIOGAS

Applications For Compression

Compressing biogas reduces storage requirements, concentrates energy content and increases pressure to the level needed to overcome resistance to gas flow Sometimes the production pressure of a biogas source does not match the pressur requirements of the gas utilization equipment. Compression can eliminate th mismatch and guarantee the efficient operation of the equipment.

Systems that use biogas for digester mixing employ compressors (or blowers) to overcome the resistance to gas flow imposed by the digester contents. Moreover large biogas systems rely on compression to reduce the size of the gas storage facility or to transport the biogas to a pipeline. Biogas systems that fuel cars o trucks use compressors to achieve the high energy density required by the application. The choice of either a blower or compressor depends on the amount of pressure increase needed. Regardless of the pressure requirements, both devices must meet stringent design specifications for handling biogas.

Special Requirements for Handling Blogas

Compressing biogas requires a gas compressor suitable for <u>flammable</u> gases These differ from regular compressors in several respects:

- o the cylinder is located further from the crankcase,
- o higher quality packing is used,
- o hardened connecting rods are used,
- o passageways are provided to vent leaks away from the crankcase and prevent explosions,
- o inlet and exhaust ports are designed to let contaminants pass through instead of collect in the compressor, and
- explosion proof motors and electrical connections are used or all equipment.

Compression requires a "clean" gas that has had the H_2S removed. Biogas typically contains 1000 ppm to 2% H_2S by volume. H_2S must be removed before compression since it forms an acid when combined with the water vapor present in the gas. The resulting acid corrodes compressor parts and will lead to premature equipment failure. Additionally, removing the CO₂ and water vapor also improves the energy value of the compressed biogas and eliminates the cost of compressin undesired and unusable gas components.

Condensation can be a problem in the compressor's gas outlet line or at othe locations in the gas train experiencing excessive pressure drop. Coolers are use (e.g. shell and tube exchanger), especially between the stages of a multi-stag machine to localize and control condensation. Water traps should be provided of the inlet and discharge gas lines of all compressors used in biogas systems.

Some researchers have reported problems with freezing in piping downstream of the compressor, when pressure regulating devices expanded the compressed ga Typically, the gas is passed through a restriction that lowers the pressure (i. et throttling the gas.) The temperature of a throttled gas may be either higher of lower after throttling than before throttling, depending on the values of the initial pressure and temperature (P_1 and T_1), respectively, and the final pressure (P_2 For certain values of these properties, the value of the final temperature (T_2) ma decrease enough to cause freezing. Freezing can be predicted by determining the slope of a constant enthalpy line on a T vs. P diagram for the biogas. The slope is known as the Joule-Thompson coefficient, and is mathematically described by th equation:

$$\mu = (T/P)_{h}.$$

where: $\mu =$ Joule-Thompson coefficient

 $(T/P)_{h}$ = change in temperature (T) with respect to pressure (P) at constant enthalpy (h).

If μ is positive, the temperature will decrease during throttling. If it is negative, the temperature will rise. If freezing could occur, the system desig parameters may be altered to change the values of P₁, T₁, and P₂. If desig changes are impossible, heat may be added (e. g., from engine cooling water) to th throttling process.

Selecting a Blower or Compressor

The choice of blower or compressor will depend on the amount of pressur increase required by a system. Blowers are employed to overcome piping pressur drop or for filling low pressure storage vessels. Compressors are typically used t obtain either medium (around 200 psi) and high (2000 psi or more) pressures. Som medium pressure compressors that handle small biogas flows are called boosters.

A typical biogas compressor and the accessories and controls needed for effective operation is depicted in Figure 6-1.

When deciding which equipment is best suited for a system, the followin points should be considered:

- o Any part of a component that contacts the biogas stream should be stainless steel, if possible. Other materials such as aluminum ductile iron, and high grade carbon steel can be used in some case since they provide good corrosion resistance and cost much less.
- o Copper or brass components should not be used where they may contact biogas.
- Accessories like flame arresters and check values are not alway essential, although they may be required by local codes and insurance companies. They make a system safer and their use i highly recommended.
- o Some companies (especially valve manufacturers) use special coatings on equipment used in biogas systems. These coatings are less expensive than stainless steel, but it must be assured that the coating will provide sufficient protection against biogas corrosion.

In the short term view these requirements only appear to increase the cost of a biogas system. However, using the wrong materials or skimping on condensate traps and other accessories will shorten the useful life of the system, and will compromise not only its long-term reliability, but also personnel safety.

Power Needed for Compression

The energy required for compression represents a major operating cost of a biogas system. Accordingly, estimating the energy requirement becomes ar important component of the system design effort. Estimates are usually based on ar adiabatic compression process (compression without cooling) since such a calculation estimates the maximum energy required for compression in a frictionless compressor.



Figure 6-1. Components of a Typical Biogas Compressor

Source: AC Compressor 1986

The non-linear relationship between the horsepower required to compress the as and the compression ratio (the final pressure divided by the initial pressure) is illustrated in Figure 6-2. The figure was generated by holding the compressor's apacity constant while allowing the value of the compression ratio to change. A inear relationship between the horsepower requirement and the compressor capacity exists when the compression ratio is held constant, and is shown in Figure 6-3. In general, the horsepower requirement is a non-linear function since the capacity and ompression ratio are both likely to change in an actual system.

Mathematically, the relationship between the system pressure, the compressor apacity, and the energy required for compression in a frictionless, adiabatic ompressor can be stated as:

$$w = C_1 R T_1 [(P_2/P_1)^{C_2} - 1]$$

where:

- w = shaft work required for compression (horsepower)
- $C_1 = k/(k-1)$
- $C_2 = (k 1)/k$
 - k = the ratio of specific heats of the biogas (C_p/C_v) , 1.3*
 - R = gas constant for the biogas (Btu/lb/°R), 0.0729^{*}
- $T_1 = initial temperature (°F)$
- P_1 = initial pressure (psig)
- $P_2 = final pressure (psig)$
- * values for 60% CH₄, 40% CO₂ biogas

The value of "w" represents the amount of energy required to compress biogas f a known composition adiabatically and reversibly from P_1 to P_2 . However, compressors are never 100% efficient because of friction and heat transfer that ccur during the compression process; and, therefore the actual energy required will e greater than computed using the preceding equation. It should be noted that hanufacturers literature will indicate different efficiencies for almost every compressor. Confusion can be avoided by asking the manufacturer of the compressor being analyzed for the actual energy consumption of the equipment.





Source: Heisler 1981

Figure 6-3. Compressor Horsepower Variation with Capacity



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Compressor energy requirements are typically presented as percentages of the available energy in the biogas. However, these figures do not include the energy required to power the prime mover of the compressor. Adiabatically compressing biogas just a few psi requires less than 1% of the available energy. The energy requirement increases to 3% of the available energy when compressing to 200 psi. About 8% of the energy in the generated biogas is needed to achieve pressures of 2000 psi or more. Some horsepower requirements for various pressures and compressor capacities are presented in Table 6-1.

The choice of prime mover and fuel for the compressor can be identified by an economic analysis of the biogas system. The costs of the equipment and the required energy must be balanced against the savings and/or revenues generated by operating the system. Rarely will biogas be an economical choice for fueling the prime mover unless the biogas system includes cogenerating capability.

Start-up energy could become a major operating cost if the compressor is improperly sized. An oversized compressor starts and stops more than a properly sized one. With start-up energy requirements being 2 to 4 times that needed for continuous operation, oversizing should be avoided.

Table 6-1. Horsepower Requirements for Compressing Biogas

Inlet Condition : $P = 14.696$ PSIA, $T = 14.696$	60° F
Capacity = 4.375 cfm	

Final Pressure (PSIA)	Horsepower
19.8	0.17
50.0	0.72
75.0	0.98
100.0	1.17
125.0	1.33
150.0	1.46
175.0	1.57

Source: Heisler 1981

Energy Density and Storage Volume

As the biogas is compressed to higher pressures, its mass is pushed into smaller volume. This raises the energy density of the gas and reduces the requir storage volume. The storage requirements and energy density for a gas that h been isothermally (constant temperature) compressed are listed in Table 6-2. No that the energy densities are much higher for biogas that has had the H_2S , CC and water vapor removed (100% methane). Keep in mind that the higher t compression ratio, the higher the costs associated with compressing the biogas.

Table 6-2. Effect of Pressure on Energy Density and Storage Volume

1	Compression Ratio	Volume ^a (cft/cft)	Energy Density ^b (Btu/scf)	Storage Medium
	For 60% Me	thane Biogas N	<u>fixture</u>	
	1	1	545	in digester
	2.4	2.4	1,310	floating roof or flexible bag
	7.8	7.8	4,600	low pressure steel tank
	21.4	21.4	11,450	medium pressure steel tank
	69.0	72.0	39,240	high pressure steel tank
	205.1	250.0	136,250	high pressure steel tank
	For 100% M	ethane Biogas	Mixture	
	69.0	72.0	66,000	high pressure steel tank
	205.1	250.0	228,000	high pressure steel tank

a - Gas volume at standard temperature and pressure, per unit of storage

b - Lower heating value

Source: Pearson 1979

CHAPTER 7 STORAGE OF BIOGAS

Purpose of Storage

Biogas is not always produced at the time or in the quantity needed to satisfy the load that it serves. When this occurs, storage systems are employed to smooth out variations in gas production, gas quality, and gas consumption. The storage component also acts as a buffer, allowing downstream equipment to operate at a constant pressure.

Types of Storage

Several methods for storing biogas have been successfully demonstrated or suggested by researchers working in the area of biogas utilization. Seven possible options (Stahl 1983) are illustrated in Figure 7-1.

A biogas system with 3 possible gas utilization options; including direct use, compression by a blower and storage at low pressure, and compression and storage at medium pressure are illustrated in Figure 7-2. The technical requirements, capital cost, and operating cost of each option (Heisler 1981) are also shown in the figure.

<u>Direct Use</u>. In some cases the match between gas production and gas usage is close enough to allow direct use of the gas. Any gas that is not used as it is produced is vented to the atmosphere. Some direct use systems usually rely on a pressure regulating device in the gas line to ensure that sufficient gas pressure is available at the burner or gas converter. Other direct use devices such as the Tracker-Trol \oplus by Perennial Energy, Inc. (Walsh <u>et al.</u> 1986) adjust the engine or burner throttling according to pressure or biogas availability. Direct use systems are lower in capital cost and less complex than systems employing storage. However, it is rare that the match between production and usage is good enough to prevent biogas waste or make the direct use system very efficient.

Low Pressure Storage. Low pressure storage options have been successfully demonstrated by several research organizations and universities. They typically operate below 10 inches water gauge, but some options are capable of much higher pressures. Generally, low pressure storage vessels cost more but the systems feature the lowest operating cost of any storage option.






Source: Heisler 1981

Biogas can be stored between the liquid level of the digester and the digester cap. The roof can float (i.e. rise as more gas is stored) or can be made of flexible material. Restraining the top will increase the pressure under which ga can be stored. Most systems employing these types of storage vessels hold bioga at pressures under 10 inches of water gauge. The major advantage of a digester with an integral storage component has to be the reduced capital cost of the system. However, such a design features several areas that require species attention. The roof of the digester must be insulated. Uninsulated covers ar susceptible to large temperature fluctuations which will cause operating problems i the digester. Floating and flexible covers present a second problem. They must be protected against wind loading, perhaps by a building or shelter.

Biogas may be stored in flexible bags. The bags are manufactured from impermeable materials such as rubber, plastic, or fiber-reinforced plastic. Thes bags are tough but can suffer damage by puncture. They are also subject to hea gains and losses if they are not insulated. Bags have also been used between th liquid level and cap of a digester but most are used as liners in steel or concret tanks. Some larger systems use a bag or flexible roof to hold biogas at low pressure and then draw the gas off for cleaning, compression, and subsequen storage at a higher pressure.

Some systems use water sealed gas holders for low pressure storage. Such a unit operates between 6 inches and 10 inches water gauge. Care must be taken to prevent the water in these devices from freezing.

<u>Medium Pressure</u>. If a system requires a gas pressure greater than several ps but less than 200 psi, clean biogas (H_2S removed) may be compressed and stored in tanks such as propane gas tanks. These tanks are typically rated to 250 psia Compressing biogas to this pressure range costs about 5 kwh per 1000 ft³ o approximately 3% of the energy content of the stored biogas. At these highe pressures, insurance investigations may be required. Local pressure vessel code may also apply. Pressure safety devices are a must (and are required by law).

Tanks, compressors, blowers, and all metal hardware must be protected from corrosive "raw" biogas. H_2S must be removed from the gas to insure safe operation of these components. Unscrubbed biogas can lead to early failure of compressors and other metal components. Once corrosion starts, the safety of the entire biogas system is compromised.

Medium pressure storage tanks are less expensive than their low pressure counterparts but the requirements for compression and gas cleanup make medium pressure storage more expensive. In exchange for the higher cost, the same volume of gas can be stored in a smaller vessel and the stored biogas possesses a higher energy density than that in a low pressure system.

High Pressure Biogas Storage

High pressure storage of gas is used in cases where very high energy densities are required or the size of a system's storage facility must be limited. High pressure storage systems are intended to maintain pressure between 2000 - 5000 psi. Compression to 2000 psig requires nearly 14 kWh per 1000 ft³ of biogas, or about 8% of the available energy. The gas is stored in steel cylinders similar to those used to store commercial compressed gases such as nitrogen. Large high pressure storage facilities have made use of longer, interconnected, convex-ended cylindrical steel tanks.

Since corrosion becomes more of a problem as pressure increases, the requirements for drying and scrubbing the gas are more stringent than for medium pressure systems. Safety also becomes more important. Tanks must be properly constructed and fitted with suitable safety devices (bursting disk devices are suitable in this case). System controls must prevent overpressurization of the storage facility. Although the initial cost of storage vessels is low, overall system costs are high and limit high pressure storage to large facilities or special applications like vehicle fuel or the sale of pure methane.

Absorption Storage

Absorption of methane in liquid propane has been suggested as a way to store clean, dry biogas. The methane dissolves in the propane resulting in a 4- to 6-fold increase in the amount of gas stored at a given pressure. Only 4% of the storage medium (propane) escapes when the methane is removed. However, the technology remains unproven, and some researchers think the technique may require refrigeration. The requirements of H_2S , CO₂, and water vapor removal coupled with the need for refrigeration make this an extremely expensive storage alternative suitable only in special cases.

Liquefaction

It is a common error to assume methane can be liquefied at ambient temperatures like propane and butane. Liquefaction of biogas requires temperature of $-59^{\circ}F$ at atmospheric pressure. Since CO₂ solidifies at $-11^{\circ}F$, CO₂ can be present. Trace impurities in the gas can cause problems at these los temperatures as well. Although the liquefying temperature can be raised increasing the pressure ($-14^{\circ}F$ at 682 psia), the technology is limited to lar systems because of the extremely high costs.

Considerations

Five factors must be studied to determine the type of storage facility requir by a biogas system. These are:

- o safety,
- o volume,
- o pressure,
- o location,
- o and fluctuations in gas production.

<u>Safety</u>. Unscrubbed biogas contains H_2S and is extremely corrosive Moreover, its corrosiveness increases with increasing system pressure. Unlet cleaned, the biogas will quickly corrode metals, drastically reducing their useful liand creating a safety hazard. The H_2S in biogas is also toxic to human Therefore, all storage vessels should be adequately vented when personnel muenter them. If not, death can result. This also goes for buildings which how digesters and their storage facilities. In these facilities, adequate ventilation mube provided to prevent a buildup of biogas in the space from small leaks. Biog can be heavier or lighter than air depending on its CH_4 to CO_2 ratio. The dang of fire is reduced for outdoor installations.

<u>Volume</u>. Proper sizing of a storage vessel depends on the volume of g produced and the volume of gas required by the end user. The designer compar the daily production pattern to the need for biogas throughout the day. The storag vessel is sized so that the usage requirements are economically satisfied. Storin more than one day's production has proven uneconomical for small scale system (Heisler 1981) and any unused gas is usually vented or flared to the atmosphere. <u>Pressure</u>. The minimum pressure will be dictated by the gas utilization equipment. Piping losses must be included when determining the minimum system pressure. The system pressure must be sufficient to insure the safe, efficient operation of all equipment. Increasing storage pressure can reduce the required storage volume as shown in Table 6-2. Pressurization equipment allows the use of less expensive filters (with higher pressure drop specifications). This helps offset the increased operating costs when blowers or compressors are used.

Location. Safety and system losses are influenced by the location of the storage facility. Long piping runs with bends and valves may require blowers to maintain system pressure at the required level. Proximity to buildings and the general public must be considered from a safety standpoint and in light of local building codes.

<u>Production Fluctuations</u>. Daily fluctuations in gas production can lead to pressures below the minimum pressure required by the gas utilization equipment and peaks in gas pressure above the maximum specification as well. Adding pressurization equipment would prove more economical than designing the digester to handle these wide fluctuations in pressure.

<u>Materiais</u>

A wide variety of materials have been used in making biogas storage vessels. Medium and high pressure storage vessels are usually constructed of mild steel while low pressure storage vessels can be made of galvanized iron, concrete, and plastics. Each material possesses advantages and disadvantages that the system designer must consider. Plastics reinforced with scrim appear to be the most popular material for flexible digester covers in the United States. The materials are similar to those used as liners for treatment ponds and containment of hazardous wastes. In several cases, exposed scrim fibers have wicked in solutions that have weakened the fabric joints of these materials. The newest reinforced plastics feature polyester fabric which appears to be more suitable for flexible digester covers. A summary of the devices, materials, and equipment sizes for storage of biogas at low, medium and high pressure is provided in Table 7-1. The most popular materials of construction for storage vessels and details some of the pros and cons of each one are listed in Table 7-2.

Table 7-1. Examples of Biogas Storage Options

<u>Pressure</u>	Storage Device	<u>Material</u>	Size
Low (2-6 psia)	Water Sealed Gas Holder	Steel	3,500ft ³
Low	Gas Bag	Rubber, Plastic, Vinyl	150- 11,000ft ³
Low	Weighted Gas Bag	Same	880- 28,000ft ³
Low	Floating Roof Reinforced Plastic	Plastic,	Var. Vol. Usually less than 1 Day's Production
Medium	Propane or Butane Tanks	Steel	2000 ft ³
High (2900 psia)	Commercial Gas Cylinders	Alloy Steel	350 ft ³

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Table 7-2. Materials of Construction for Biogas Storage Vessels

<u>Material</u>	Advantages	<u>Disadvantages</u>
Mild Steel	Usually the lowest cost material. Has a long life when properly painted and maintained.	Mild steel rusts, especially on the outside. Surface must be properly prepared. Grit- or sand-blasting is the preferred method. Remove all rust and mill seals before painting.
Galvanized Iron	Available at low cost. Years of good service when properly painted and maintained.	Must be treated before paint will adhere. Unpainted tanks have a useful life of about five years.
Concrete	Low cost, long life	Requires coating on inside to prevent H ₂ S "crowning" or erosion
Ferrocement	A new technology consisting of rich cement mortar impregnated with wire mesh. Less expensive than mild steel vessel of the same size. Suitable for pre- cast products.	Requires skilled labor to manufacture. Requires a coating on the inside and outside to improve the impermeability to gas. Must be leak tested.
Plastic (PVC, HDPE, <3 mm thick)	Readily available and easy to work with.	Plastics degrade in sunlight unless UV treated. Expensive.
Hypalon ©	Reinforced for added strength	Prone to "wicking" when used as a floating top.
XR-5 ©	Polymer based fabric reinforced sheet that addresses the wicking problem. Good resistance to chemicals. Does	Sometimes difficult to seal. ater.

Source: ESCAP 1980

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CHAPTER 8 BIOGAS UTILIZATION TECHNOLOGIES

Introduction

There are several viable options for the utilization of biogas as shown in Figure 8-1. Foremost among these are:

0	direct combustion,
0	fueling engines, and
0	sales to natural gas pipelines.

Direct Combustion

Direct combustion is inarguably the simplest method of biogas utilization. Conversion of combustion systems to biogas combustion is basically a matter of fuel orifice enlargement and intake air restriction, with attendant modification of the fuel delivery and control system.

However, when implementing these modifications with either new or retrofitted systems, a number of variables should be considered; including the heat input rate, the fluid handling capabilities, flame stability, and furnace atmosphere.

<u>Heat input rate</u>. Because biogas sometimes has energy values lower than 400 Btu/SCF, some combustion systems will be restricted by a limit in volumetric fuel throughput, including the supply to the combustor. The result is a decrease in equipment output (derating) which must be evaluated for each combustion unit.

<u>Fluid handling capability</u>. Besides the combustor, the rest of the fuel system (flues, piping, valves, and controls) must be evaluated to determine if increased fuel and exhaust flows, and decreased flow of combustion air, can be handled.

Flame stability. Since flame or burner stability is primarily a function of flame velocity and flammability limits, it must be evaluated both theoretically and empirically for individual sources of biogas. Biogas may produce a slower flame speed (relative to natural gas) and a higher volume of biogas must be fed to a burner to maintain an equal heat input, or the flame may "blow off" the burner tray.

FIGURE 8-1. BIOGAS UTILIZATION OPTIONS



<u>Furnace atmosphere</u>. Because of the corrosive nature of biogas containing hydrogen sulfide and moisture, the burner and its combustion zone should be adequately protected. Corrosion of iron, copper, and steel components in the combustion, heat transfer, and exhaust zones of a combustion system should be carefully evaluated. To help protect from moisture and H_2S corrosion, system temperatures should be maintained above the dew point temperature (approximately 260°F) to prevent condensation. In biogas fuels with high H_2S levels, sulfur compounds have been reported to accumulate at and around the burner.

To help maintain operation above the dew point, boiler water temperatures should be maintained in excess of 220°F at all times. In the case of a "cold start", a boiler should be fired with natural gas, propane, or fuel oil until the system is up to operating temperature (Parish 1986). Also, preventing the stack temperatures from falling below dewpoint may be accomplished by bypassing the second pass of a boiler unit. Although this helps prevent sulfurous and sulfuric acid formation and subsequent corrosion, boiler efficiency may be adversely affected. Similar concern should be given to the use of stack gas economizers, which should not use feedwater with temperatures less than 250°F or reduce stack gas temperatures below dew point.

Burner Conversion

Burner conversion to fire biogas rather than natural gas or propane involves insuring that an exit velocity and corresponding pressure drop of the biogas is maintained for proper fuel and air mixing (Parish 1986). The pressure drop across a burner orifice will increase with decrease in heating value and specific gravity of biogas relative to natural gas and propane.

This increase in the pressure drop can be determined by the equation:

 $\frac{P \text{ Gas } A}{P \text{ Gas } B} = \frac{(\text{Heating Value Gas } B)^2 \times \text{Spg Gas } A}{(\text{Heating Value Gas } A)^2} \text{ Spg Gas } B$

For example, if natural gas (1050 Btu/SCF, 0.65 spg) is replaced by a typical biogas (550 Btu/SCF, 0.80 spg) the increase in pressure drop across the orifice would be:

$$\frac{P Biogas}{P Nat Gas} = \frac{(1050 Btu/SCF)^2 \times 0.80}{(550 Btu/SCF)^2} = 0.65$$

= 4.490 times the pressure drop across the natural gas burner orifice.

To compensate for this increase in pressure drop, the orifice diameter must be increased. An estimated orifice diameter multiplier for converting natural gas and propane appliances to fire on biogas at different methane contents is provided in Table 8-1 (Parsons 1984). Permanently increasing an orifice diameter to accommodate biogas, however, may degrade the performance of the burner if returned to use with natural gas or propane. This is an important consideration when an operation requires the flexibility of switching between fuels due to biogas availability.

To maintain dual-fuel capability, gas blending or dual-fuel burners can be implemented. An orifice modification can be made based on a fuel gas of either biogas or a biogas/ natural gas/ propane blend. To maintain burner performance, the fuel gas mixture must provide an equivalent heat input and pressure drop to the fuel gas mixture used for the orifice design. This can be accomplished by blending biogas, natural gas, or propane, or by blending natural gas or propane with air to produce a mixture with an equivalent heat input (and pressure drop) as the biogas.

	Orifice Diameter Multiplier				
Percent Methane in Biogas	Natural Gas (1.050 Btu/ft ³)	Propane (2,500 Btu/ft ³)			
70%	1.32	1.63			
65%	1.39	1.72			
60%	1.46	1.81			
55%	1.54	1.92			
50%	1.64	2.04			

Table 8-1. Orifice Diameter Multiplier for Gas Appliances

Example: A natural gas appliance with an orifice diameter of 0.1° would have to be enlarged to $0.1 \times 1.54 = 0.154^{\circ}$ diameter for a biogas with 55% methane.

Notes:	The area multiplier is the diameter multiplier squared.
	Gas densities @ 68°F and 14.7 psia
	Carbon dioxide= 0.01147 lb/ft ³
	Natural gas = 0.0506 "
	Methane = 0.0417 "
	Biogas, 60% methane= 0.0709 "
	Dry Air= 0.0752 "

Source: Parsons 1984

An indicator of this fuel mixture compatibility with the burner orifice design is the Wobbe Index. This index is defined as:

Wobbe Index = $\frac{H_o}{(G_o)^{1/2}} = \frac{H_m}{(G_m)^{1/2}}$

Where:

H = heating value of gas
G = specific gravity of gas
o = original gas
m = substitute mix including pure substitute and air

Source: North American Manufacturing 1978

The concept is to create mixtures with similar Wobbe Index Numbers to allow proper combustion system operation.

The other option for achieving fuel flexibility is the use of dual-gas burners that can maintain the orifice pressure drop for each fuel gas independently. A dual canister burner can provide a separate set of orifice jets for each gas (Parish 1986) to allow for independent fuel flow. On smaller systems such as water heaters, burner trays can be easily removed and interchanged so that a biogas tray can be replaced by a propane gas tray in the event of a biogas shortage (Walsh <u>et al.</u> 1986).

Since many systems operate intermittently, consideration must be given to the type of pilot used to ignite the fuel mixture. Biogas pilots have been used with success; however, some installations have experienced problems with pilot extinguishing, which led to the installation of a separate propane pilot (Walsh <u>et al.</u> 1986). Some water heater and boiler systems are specifically designed to operate on biogas fuels. Several of these are listed in the Appendix A.

Absorption Chillers

A biogas conversion method with limited application to date involves absorption heating and cooling. Utilizing biogas in a gas burner, a double-effect absorption chiller-heater can be used to provide chilled water for refrigeration and space cooling and hot water for industrial processes and space heating.

This system is similar to vapor-compression refrigeration, except that the high pressure side of the system has a series of heat-transfer vessels and a pump rather than a compressor. Most absorption systems utilize ammonia as the refrigerant and an ammonia solution as the solvent/absorbent (Salisbury 1950). However, for airconditioning work, brines of lithium chloride and lithium bromide have been used.

An example of a double-effect absorption cycle is shown in Figure 8-2. As discussed in a preceding section, conversion of the burner from natural gas to biogas is relatively simple. While most of these systems are sized in the range of 100 ton capacities, some smaller units are commercially available. Since 1985, two direct-fired, double-effect chillers have provided refrigeration for egg storage and space heating in an egg processing plant with no problems with burner conversion or operation (Knight and Clement 1986). These particular systems have an advertised cooling coefficient of performance (COP) of 0.95 and heating efficiency of 83% (Yazaki 1987). These double-effect systems also can be configured for simultaneous heating and cooling applications. Costs for these units are in the range of \$150 to \$500 per ton of capacity.



Figure 8-2. Double-Effect Absorption Chiller Cycle

Source: Yazaki 1987

Gas Turbines

There is limited information on the fueling of gas turbines with biogas. These machines and their peripheral equipment require fuel gases with very low concentrations of particulates and moisture. Many manufacturers recommend gas qualities similar to those required by utilities for pipeline quality natural gas.

As shown in Figure 8-3, gas turbines have a theoretical efficiency advantage over steam turbines for systems at low and medium capacities and an advantage over internal combustion engines at higher capacities. Therefore, gas turbines offer efficiency advantages over other systems, if the problems of particulates and moisture can be cost effectively overcome. However, there have been only a few successful applications in biogas fueling of gas turbines to date (Energy Research and Applications 1981a).



Figure 8-3. Efficiency Ranges of Prime Movers

Source: Waukesha 1986

Engine Systems

Internal combustion engines have been fueled by biogas from municipal digester systems for more than 40 years with varying degrees of success. In recent years, this application has been extended to agricultural and industrial systems for a variety of power requirements. Stationary spark ignition engines can supply power for many loads including:

- o cogeneration,
- o pumps,
- o fans and blowers,
- o elevators and conveyors, and
- o heat pumps and air conditioners.

There is also the potential for biogas fueling of cars, trucks and industrial equipment including tractors.

Evaluation of which system would provide optimum economic use of a biogas source hinges on a number of considerations including:

<u>Degree of utilization</u>. What combination of engine systems will provide the most efficient use of biogas on a daily basis throughout the year? Will a gas compression system or other special gas handling system be required?

<u>Cost of installation</u>. Cogeneration systems are fairly expensive when compared to reducing a high electrical load by replacing electric motor shaft with horsepower from a biogas fueled engine. Cogeneration systems also typically require costly interconnect and control systems. Before making electricity, look at shaft horsepower applications first.

<u>Cost of operation and maintenance</u>. One large engine plant will inevitably have lower operating costs than a few smaller plants. The larger loads should be satisfied first before looking to relieve smaller loads. The costs of providing backup power to a conversion in the case of an engine failure or fuel unavailability should be carefully evaluated.

<u>Degree of interference with current operations</u>. Any engine application to replace an electric motor in an industrial process will mandate that consideration be given to load management and control. Engines also have higher maintenance requirements, in both materials and labor.

Cogeneration

Cogeneration is best defined as the simultaneous production of two or more forms of energy from a single fuel source. In the following discussion, the two forms of energy exemplified are electricity and thermal energy in the form of hot water. Other applications include fueling an engine for shaft horsepower (for pumps, blowers, etc.) and thermal energy (space heating, hot water, absorption chilling, etc.). Additionally, cogeneration can take the form of using biogas to fuel a steam boiler for producing steam for a steam turbine for producing shaft horsepower, electricity, and hot water. An example of an industrial cogeneration system is illustrated in Figure 8-4.





Source: Wilkinson and Barnes 1980

The layout of a small-scale (55 kW) cogeneration system including the major components of power unit, generator, heat recovery system, and controls is shown in Figure 8-5. This section will provide practical technical information on the selection and operation of these various components relative to fueling by biogas.

Power Units

<u>Unit Sizing</u>. The sizing of a cogeneration system will have an impact on the overall capital cost of the system, and the efficiency of the system to produce electricity and hot water. Optimal utilization is a function of operational energy needs (electrical and thermal), the output of the cogeneration system, and the rate of production and storage of biogas for use by the system.

As illustrated in Figure 8-3, there are three basic options for prime mover in a cogeneration system: reciprocating (internal combustion) engines, gas turbines, and steam turbines. The ensuing discussion will be limited to internal combustion engines, specifically spark ignition and compression ignition units.

Matching an Energy Load. Once the diurnal energy pattern of an operation has been established, an attempt can be made to match cogenerator operation to provide the most power over the longest period of time. This procedure is illustrated in Figure 8-6 where the electrical load of a dairy is evaluated for cogenerated electricity. In this example, if biogas availability allows for the production of 1000 kWh of electricity per day, it may be economical to provide 50 kW for 20 hours per day rather than 100 kW for 10 hours per day. Most engine manufacturers recommend continuous operation of their units over intermittent operation for maintenance and longevity reasons.

In other operations, however, it may be more economical to use the cogeneration system to either match or shave peak loads in order to reduce utility demand charges. Sizing of a cogeneration system, therefore, would primarily be a function of the amount of biogas that can be economically stored and the peak demand period that must be met. Peak shaving requires a greater degree of system control and reliability to be effective.

In all cases, the radiator for a cogeneration system should be sized to meet the full load cooling requirements of the system. This will permit operation of the system at full electrical power output during periods of low thermal energy demand or heat recovery system failure.

Source: Walsh and Ross 1986

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- Emergency heater for digester start-up
- Circulation pump for emergency heater
- Circulation pump for digester heating water
- Control valve to keep heating water to digester below 1400F Z
 - Heat exchanger to recover heat from engine cooling water X
 - Circulation pump for engine cooling water
- A A A Control valve to maintain engine inlet cooling water temperature at 1900F.
 - TOTAIDER
 - Engine exhaust to atmosphere.
 - Heat exchanger to recover heat from engine exhaust P OKST
 - Engine exhaust manitold
 - Engine valve covers (2)
 - Spark pings (6)
 - blotinem existri enign3
 - cer pressure
- 0 N Tracker-Trol pressure regulator which increases throttle setting with increase in diges-#1330341
 - M T
 - Blogst fuel carouretor
 - Biogas pressure regulator to biogas fuel position.
- к 1 Solenoid valve for blogst automatically opens when engine starts and controls are set Biogas fuel line manual lacistion - opened when switching to biogas
 - Propane fuel carburetor
 - Propare tuei line manual isolation valve closed when awitching to blogas н 9
 - Propane low pressure regulator
 - đ
 - Propane high pressure regulator
 - roisized teut ensort of
- Solenold value for propare automatically opens when engine starts and controls are set Э
 - Air filter and compution air intake ā
 - 28 Control Panel
 - Generator
 - Engine v



Figure 8-5. Typical Biogas Cogeneration System



System Oversizing. Oversizing a unit can have serious ramifications on the electrical efficiency of a system. As shown in Figure 8-7, the efficiency of a 55 kW cogeneration system experienced a sharp decrease in electrical efficiency once the generator load fell below 30 kW or 55% of the maximum output (Walsh <u>et al.</u> 1986). Similarly, Jewell <u>et al.</u> (1986) suggests that a cogeneration unit be sized to operate at no lower than 60% of the maximum power.

While evaluating the thermal load of an operation, the quality (i. e., temperature) of the heat recovered should be considered. Additional energy may be required to upgrade this energy for actual use. Also, consider that controlled temperature anaerobic systems could require 40% or more of the energy output in the form of biogas to maintain temperature.

Engine Derating. Because biogas has a lower volumetric energy content than either natural gas or diesel fuel, an engine may be derated. For natural gas engines, this derating may be as much as 13% of the natural gas rating. Further derating can occur if changes are not made in timing, spark plug size and gap, and valve lash (Gill 1971).

Additional consideration should be given to the overall gas consumption of a unit including start-up and cool-down cycles associated with shut-downs to meet operational schedules or a lack of biogas. During these periods, engines are not



Figure 8-7. The Effect of Engine Load on Electrical Efficiency

Source: Walsh and Ross 1986

operating at maximum and loss of output must be accounted for in the overall fuel - budget. Moreover, cogeneration engines can be tuned for either maximum output to meet a certain demand, or for maximum fuel economy, producing the most power for the fuel available.

Biogas Ouality. In addition to the energy content of the biogas, engine manufacturers also have concerns with the H₂S and moisture content of the fuel Many recommend H₂S limits of 10 ppm or 0.001% by volume (Cummins 1985). If these limits are exceeded, warranties on the engine may be voided. This highlights the need for some form of gas cleanup or filtering system prior to engine fueling. Additionally, manufacturers suggest operating the engines on a clean gas during start-up and shut-down and maintaining engine oil temperatures high enough (190°F) to prevent condensation of water vapor and H₂S in the oil (Cummins 1985 and Waukesha undated). The use of positive crankcase ventilation (PCV) filters for purging moisture laden contaminated air from the crankcase is also encouraged. Although the use of mercaptan filters are strongly encouraged by most manufacturers, some research has questioned the overall performance of these filters (Clark and Marr 1985, Walsh et al. 1986).

Spark Ignition Engines

<u>Engine Modification</u>. Spark ignition (SI) engines are the easiest engines to convert to biogas due to the wide availability of natural gas fired units and the relative similarity of biogas to natural gas. There is also a large selection of diesel powered cogeneration systems in the higher output ranges (over 500 kW).

Engine conversion to biogas fueling involves engine modification in the following areas:

- o carburction,
- o spark gap settings,
- o spark timing, and
- o maintenance requirements.

<u>Carburction</u>. Carburction modification basically involves accounting for the lower volumetric heating value of the biogas relative to the primary fuel. For a natural gas fired engine, this amounts to increasing the fuel intake capacity of the carburctor and restricting the combustion air intake.

Conversion of a gasoline fueled engine would require complete conversion to a gaseous fuel carburetor sized to provide the volumetric flow necessary for maximum power output. The anticipated fuel consumption of a biogas engine is a function of the engine itself, load considerations, engine speed, air-fuel ratio, and fuel dilution. The specific power output of an engine operated at 900 rpm and a compression ratio of 15:1 can be predicted using the equation shown below as developed by Neyeloff and Gunkel (1981).

SPO = $-154.8 - 9.24 \times 10^{-2}$ D + 41.9R - $3.24 R^{2} + 7.78 \times 10^{-2}$ R³

Where:

SPO = specific power output, HP/L CH₄/min x 100 D = percent dilution, $(CO_2/CH_4) \times 100$ R = percent fuel-air ratio, $(CH_4/air) \times 100$ (Note: 28.3 L/SCF)

The fuel consumption pattern of a 25 kW cogeneration unit at various loads and air-fuel mixtures is illustrated in Figure 8-8. Walker <u>et al.</u> (1985), noted the difficulty in physically adjusting the carburetor for maximum efficiency.

Figure 8-8. Fuel Consumption of a 25 kW Cogeneration Unit



Source: Koelsh 1982

In the design of a system, the incorporation of a secondary fuel supply such as natural gas or propane should be considered in case the biogas fuel supply is interrupted and continued service is required. An example of biogas carburction with a secondary fuel supply is illustrated in Figure 8-9. Recommended fuel pressure requirements will vary between 2-20 psig for naturally aspirated engines and 12-20 psi for turbocharged engines (Caterpillar 1972). Caterpillar also recommends providing engine air intake at a rate of 3 CFM per engine horsepower.

<u>Throttle Controls</u>. In lieu of fixed throttle controls for maintaining a constant power output, there are some throttle control devices which track certain fuel or load factors to vary engine power. A commercially available system is the Tracker-Trol \circledast which allows for the throttle to vary with the biogas fuel pressure (Walsh <u>et</u> al. 1986). This permits continuous engine operation without substantial gas storage; however, the floating throttle setting reduces the engine load causing a reduction in engine power efficiency (Walsh <u>et al.</u> 1986). There are also other commercial products on the market that utilize microprocessor controls to optimize power output by monitoring fuel quality, intake air conditions, engine conditions, and system load (Waukesha 1987a).

Figure 8-9. Biogas Carburetion with Secondary Fuel Supply



Source: Stahl et al. 1982b

<u>Air-Fuel Ratio</u>. When modifying engine carburction, consideration must be given to the Air-Fuel Ratio in order to obtain optimum performance. As seen in Chapter 3, the stoichiometric Air-Fuel Ratio for a biogas of 60% methane is 6.03.

Derus (1983) recommended that minimum methane concentrations of 35% and heating values of 400 Btu/SCF be maintained for operation of a four cycle internal combustion engine. Similarly, a methane and carbon dioxide mixture will not combust if the volumetric amount of carbon dioxide is greater than three times the amount of methane (Coward and Jones 1952). This is of particular concern when using biogas generated from landfill operations.

Equivalence Ratio. Jewell <u>et al.</u> (1986) noted that optimum electrical efficiency $(E_{el} = 26\%)$ was obtained by operating a cogeneration unit at an equivalence (Air-Fuel) ratio of 0.8 - 0.9. The E_{el} dropped markedly below 20% as the equivalency ratio was raised with a rich fuel mixture (up to 1.3). Optimum performance under lean fuel conditions was also confirmed by Stahl <u>et al.</u> (1982b) using similar tests.

The effect of Air-Fuel Ratio on the performance of a power unit is illustrated in Figure 8-10. Neyeloff and Gunkel (1981) determined that optimum Air-fuel Ratios were between 7.69 and 11.76 pounds of air per pound of methane.



Figure 8-10. Effects of Equivalence Ratio on Engine Performance

Source: Stahl 1983

<u>Spark Plugs</u>. While engine manufacturers suggest the use of cooler plugs for gaseous fuels, Jewell <u>et al.</u> (1986) recommends the use of a hotter plug for biogas. Spark gaps between 0.017 and 0.030 inches proved to be adequate with no noticeable difference in performance within this range. Jewell noticed that plugs with nickel alloy electrodes experienced severe erosion within 100 hours of operation. Spark plugs were exchanged with inconel electrode plugs, which operated successfully for more than 500 hours. Similarly, Walsh <u>et al.</u> (1986) used Champion J-6 spark plugs with a spark gap of 0.025 inches with good performance and service intervals above 1000 hours.

<u>Compression Ratio</u>. Optimum compression ratios for a biogas fueled engine has been determined to be in the range of 11:1 to 16:1 (Figure 8-11). However, most industrial natural gas engines have compression ratios of 7:1 to 10:1.

Figure 8-11. Compression Ratio Versus Specific Power Output



Source: Neyeloff and Gunkel 1981

Engine Timing. As seen in Chapter 3, biogas typically has a slower flame velocity relative to other gaseous fuels. Because of this, spark timing must be retarded to allow for smoother combustion and engine operation. Figure 8-12 illustrates the impact of timing on engine power (manifold vacuum) output for a biogas of 60% methane. Jewell <u>et al.</u> (1986) noted optimum spark timing for a 25 kW engine fueled by a biogas of 60% methane to be between 33° and 45° BTDC. Walsh <u>et al.</u> (1986) also operated a 55 kW unit using a similar biogas with a spark timing of 45° BTDC.



Source: Stahl et al. 1982b

Derating. Regardless of the success of implementing these conversion techniques, a reduction in the continuous power rating of the engine should be anticipated, its magnitude depending on the methane content of the gas. Jewell <u>et</u> <u>al.</u> (1986) noted a 15-20% derating for an engine using biogas of 60% methane. The derating of a CFR engine using various levels of methane is illustrated in Figure 8-13. Similarly, torque and power outputs for a converted natural gas engine to biogas yielded outputs of 80-95% of operation on natural gas (Clark and Marr 1985).

Figure 8-13. Effect of Biogas Methane Content on Engine Derating



Source: Neyeloff and Gunkel 1981

<u>Heat Recovery</u> - Other than shaft horsepower, a tremendous amount of thermal energy is produced by combustion and most of this energy is available for recovery. A thermal energy balance for a natural gas engine is illustrated in Figure 8-14. As shown in the figure, recovery of the thermal energy from the lubricating oil, coolant cycle, and exhaust can yield as much as 80% of the fuel energy input to the engine.

On a cogeneration system with thermal energy being recovered from the engine block, there exists a critical balance between maximizing heat recovery efficiencies and maintaining proper engine block temperatures. On the one hand, engine temperatures should be maintained high enough to prevent the condensation of acid bearing fumes leading to degraded lubricating oil conditions. On the other hand, temperatures should be kept low enough to avoid damage to engine components. With a heat recovery system, great care should be taken in system design to insure adequate heat rejection from the block and to avoid "hot zones" in the engine. In both cases, the engine manufacturer should be consulted before modifications of design coolant flow rates and temperatures are made. Additionally, engine manufacturers may have recommendations for the minimum exhaust temperatures required to prevent condensation of vapors and corrosion of the exhaust vent.

For recovering energy from the engine coolant, a water-to-water, shell-in-tube heat exchanger has proven very satisfactory in performance (Stahl <u>et al.</u> 1982a, Walsh <u>et al.</u> 1986). Exhaust heat exchangers using gas-to-water heat exchangers must be able to withstand high (600-1200°F) exhaust temperatures. Utilization of the thermal energy collected from a heat recovery system is a function of the storage system employed and the energy quality requirements of a process. The temperature of hot water derived from heat recovery will probably be limited to under 190°F.

<u>Maintenance Requirements</u> - Even though an engine may be designed for longterm operation (in the range of 20,000 hours) without a major overhaul, certain maintenance procedures must be followed to assure engine longevity. Compounding the problem of maintenance is the use of a non-standard fuel such as biogas that affects engine wear allowances and component replacement cycles. Therefore, engine manufacturers recommendations should be used carefully since these typically apply only to operation on standard fuels such as propane, natural gas, and gasoline.

Figure 8-14. Thermal Energy Balance



For this reason, it is very difficult to estimate the maintenance cycles for these engines, and subsequently, the costs of maintenance. It is very important, however, that the costs of engine maintenance be reviewed in the context of biogas fueling of the engine. Oil and filter change intervals may be shorter, as may be the intervals for minor and major overhauls. This will have a serious impact on the cost per kWh of electrical production or Btu/hour of thermal energy production. Since engine maintenance costs are primarily based on the hours of engine operation, there exists a distinct economy of scale factor, i. e., a 40 kW unit will have higher costs per kWh output than a 150 kW unit.

Operation and maintenance costs of 33,700 for a 55 kW system operated for 7,880 hours per year have been reported (Walsh and Ross 1986). Pellerin <u>et al.</u> (1988) indicated similar costs for a 35 kW unit, 33,200 for 7,440 hours. Table 8-2 illustrates the various cost items and maintenance frequency for the 55 kW cogeneration system. These data compare well with a rule-of-thumb for maintenance costs of 0.0125 per kWh (Cummins 1982). A 55 kW unit operated 7,800 hours per year at 80% load would have maintenance costs of 4,300 per year.

<u>Oil Tests</u> - A major consideration in engine maintenance is the frequency of oil changes and type of oil used. Most manufacturers have recommendations for oils to be used in their engines fueled by biogas or "sour" gases and for the frequency of oil changes based on general engine operation.

In order to monitor the general well-being of an engine using biogas, oil testing is essential. Selecting an oil testing lab could be considered as important as selecting a good medical doctor. Although cost is a consideration, it should be third on the list following lab reliability and response time. Because signs of engine failure can appear within a short span of operation, being able to take an oil sample, send it to a test lab, and receive the lab report within a two week period is essential. Most test labs will provide a sample mailer with a label for detailing the source of the oil and other operational data.

Test results from the test lab must be interpreted; therefore, it is important that the laboratory chosen understands the type of engine and fuels being used. The concentration of wear metals in the sample will be dependent on the make of engine, fuel, and total hours of operation. A sample of an oil test performed on a biogas fired engine as determined by Walsh <u>et al.</u> (1986) is shown in Table 8-3. Additional information regarding the type of wear metals and the concentrations to expect, should be available from the engine manufacturer.

Table 8-2.	Engine	Generator	Main	tenance	Costs
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ITEM	<u>OUANTITY</u>	<u>UNIT COST</u>	<u>FREOUENCY</u> (hrs)	ANNUAL COST	
Oil (gal.)	5	\$ 6	600	\$394	
Oil filter	1	\$10	600	\$134	
Oildex filter cartridge	1	\$ 10	1,000	\$79	
Wix coolant filt	er 1	\$10	500	\$156	
Air filter	1	\$15	2,000	\$63	
Spark plugs	6	\$6	1,000	\$47	
Mercaptan filter	1	\$400	4,000	\$788	
Grease generator	r 1	negl.	4,000	negl.	
Minor overhaul	1	\$1,600	16,000	\$788	
Major overhaul	1	\$5,000	32,000	\$1.230	

7,884 Hours Per Year Operation

TOTAL

Source: Walsh and Ross 1986

The oils most commonly recommended are those with a high Total Base Number (TBN). TBN is an indication of the ability of the oil to neutralize strong acids formed during the combustion process. This is important where CO_2 and H_2S in a biogas can react with water vapor to form carbonic acid and sulfuric acid, respectively. A TBN test measures the quantity of chemically basic additives in detergent/dispersant, alkaline oils.

\$3,679

Engine manufacturers also provide data on other characteristics of lubricating oils including barium, zinc, and calcium contents and sulfated ash levels. For fuels with H_2S levels over 0.1%, manufacturers recommend an oil with a TBN greater than 8.0 with a minimum operating level of 4.0 (Cummins 1985 and Waukesha 1981). In order to minimize condensation of acid-bearing fumes in the crankcase, manufacturers also recommend keeping engine coolant temperatures above 190°F.

Table 8-3. Engine Oil Analysis

Sample Date	10/24/83	9/26/84	1/10/85	11/21/85	12/15/85	1/12/86	1/16/86	2/11/86	4/15/86
Unit Hours	171	327	391	629	945	1525	1624	2143	3473
011 Hours	171	156	64	238	316	580	99	519	559
011 Type/Manufaccture	10W-40	10 W-4 0	10W-30	10W-30	10W-30	10W-30	10W-30	10W-30	10w-30
	Unknown	Unknown	Mobil	Mobil	Mobil	Mobil	Exxon	Exxon	Mobil
			Delvac	Delvac	Delvac	Delvac	XD3	XD3	Delvac
			1330	1330	1330	1330	EXTRA	EXTRA	1330
011 Added (Quarts)									
	4		•		1				
Viscosity (Centistokes)	15.	8 12.4	i 12.	4 13	.8 13.	.2 16.	4 14.0)	
	13.0	6							
	13.4	4							
Water (% Vol)	-0.6	05 0.3	3 C 0.	3B -0	.05 -0.	.05 -0.	05 -0.0	15	
	-0.0	05							
	-0.0	05							
Solics (% Vol)	0.	2 1.5	5 O.	.1 0	.2 0	.4 · 0.	2-	-	0.5
Fuel Soot (& Wt)	-	-	-	-	-	-	0.1	0.	1.
Total Base Number (TBN)	11.	8 9.4	4 13	.1 13	.4 13	.7 13.	9 10.4	9.	7 9.9
Silicon (ppm/Wt)	11.3	2 10	6.	.29	.8 7.	.56.	2 2.0) 2.	0 6.3
Iron (ppm/Wt)	43.0	0 75.0) 23.	3 42	.4 23	.3 17.	2 12.1	. 11.	5 31.5
Chromium (ppm/Wt)	1.	8 1.3	31.	.1 5	.3 2	.2 1.	2 0.9) 1.	2 1.5
Molybdenum (ppm/Wt)	0.	90	0	.7 1	.1 0	.9 0	0.6	i 0	0
Nickel (ppm/Wt)	1.	3 2.1	ι ο	0) 0	0	0.7	1.	1 0.4
Aluminum (ppm/Wt)	5.	8 2.0) 2.	.2 4	.1 3	.63.	1 0.6	; 0.	3 3.2
Tin (ppm/Wt)	5.4	60	0	0	0	0	0	2.	70
Copper (ppm/Wt)	26.	5 41.9	9 B 19.	.2 34	.8 12	.63.	5 6.3	8.	9 6.6
Lead (ppm/Wt)	14.	7 22.4	12	.8 24	.6 12	.3 10.	8 4.1	6.	9 12.6
Sodium (ppm/Wt)	74.	5 103	28	.1 31	.9 270	.0 B 211.	OB 37.9	9.	7 223
Boron (ppm/Wt)	102	19.4	i 6.	.2 4	.3 2	.9 2.	9 180	181	23.4
Magnesium (ppm/Wt)	562	131	25	.7 15	.9 12	.4 12.	2 925	1035	194
Calcium (ppm/Wt)	2725	2928	5045	6388	6253	5169	1536	881	6909
Barium (ppm/Wt)	26.6	8.9	0	0.2	0.6	0.8	3.8	13.	5 1.6
Phosphorous (ppm/Wt)	1364	931	1319	963	725	960	1542	1346	1781
Zinc (ppm/Wt)	1541	1063	1385	1583	1495	1183	1611	1321	1541

(ppm/Wt)-Parts per Million by Weight

Abnormal Value Codes

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B - Slightly Above Normal. Requires monitoring.

C - High Value. Normally requires corrective action.

D - Severly Abnormal. Requires immediate corrective action.

Source: Walsh et al. 1986

Walsh <u>et al.</u> (1986) reported reaching oil changing intervals of approximately 600 hours for an engine using a 13.0 TBN oil and fueled by a biogas with 0.54 mg/L H_2S and 0.49 mg/L mercaptan levels. Jewell <u>et al.</u> (1986), however, noted that the TBN level of an engine operated on biogas with 3000 ppm hydrogen sulfide levels fell from 10.0 to 2.0 in only 55 hours. Jewell also recommended not relying solely on TBN levels for determining oil change intervals. Walker <u>et al.</u> (1985) was able to achieve oil change intervals in the range of 300 hours using a high TBN oil. Walker was able to double this interval to 600 hours using a chemically treated oil by-pass filter. The effect of oil change intervals on oil TBN is illustrated in Figure 8-15.

Extending oil change intervals can be accomplished by maintaining continuous operation of the engine to avoid condensation of acid-bearing fumes inside the combustion chamber and by "scrubbing" the gas of H_2S , mercaptans, and water prior to entering the engine (Figure 8-16). In any case, determination of oil change intervals should include input from the engine manufacturer, oil test lab, and oil manufacturer.

Because the maintenance requirements of biogas engines are not standardized or fully understood, engine failure is a distinct possibility. Bearing-related failures are commonly blamed on acid degradation of copper bearings, bushings, and pins. Jewell <u>et al.</u> (1986) experienced an engine failure after 2940 hours of operation on a high H_2S biogas. The failure was determined by the engine manufacturer to be due to the failure of a copper wrist pin bushing with subsequent destruction of the connecting rod bolt and connecting rod. Similarly, Walker <u>et al.</u> (1985) experienced failure of copper alloy wrist-pins and bearings after only 1,128 hours of operation with 3000 ppm H_2S biogas.

Jewell discovered additional pitting on rod bearing inserts, the main bearings, the contact face of the tappets, and other oil contacted engine components. Jewell <u>et al.</u> (1986), Walker <u>et al.</u> (1985), and Walsh <u>et al.</u> (1986) also noted carbon and oil deposits on top of the engine piston heads and scoring of the cylinder bores from these deposits. Walker reported that the persistence of this problem resulted in an engine overhaul to replace damaged pistons and piston sleeves.





Source: Walker et al. 1985

Figure 8-16. Typical Filter Treatment System Installation



Source: Waukesha 1981

Both Jewell and Walsh noted tarnishing of electronic contacts in the distributor and relays due to exposure to biogas. This problem can be alleviated by isolating the engine system from the biogas source as much as possible and by providing good ventilation in the engine room. The increased probability for excessive engine wear and failure highlights the need for selecting a cogeneration system with an engine with a good service record and a local distributor. Consideration should be given towards entering into a service contract with the dealer for frequent engine inspection and service.

<u>Cogeneration System Costs</u> - Costs will vary from system to system based on the amount of gas cleanup required and the type of interconnect required by the utility. The relationship between system size and capital costs is illustrated in Figure 8-17. Typical costs for systems under 100 kW are in the range of \$1,000 per kW capacity. As shown in Figure 8-17, larger systems will provide a substantial economy of scale.




Source: Jewell et al. 1986

Diesel Engines

Biogas fueling of diesel engines requires the use of diesel fuel for ignition, since there is no spark and biogas has a low cetane rating (Stahl 1983). This requires some modification of the engine including a carburetor for the mixing of biogas with intake air and a means for maintaining the desired diesel fuel setting on the injection pump, and for advancing the ignition timing (Figure 8-18).

Ortiz-Canavate <u>et al.</u> (1981) conducting tests on a Ford 4000 diesel engine (54 HP, 16.5:1 compression ratio) used a synthetic biogas (60% methane) with a diesel fuel injection rate to account for 20% of the input energy to the engine. At medium speeds (1300-1600 rpm) and high torque conditions, the dual-fueled engine exhibited efficiencies comparable to those for diesel fuel only. High speed efficiencies dropped and exhaust temperatures rose above recommended limits (1100°F) when the dual-fueled engine was operated at higher speeds. Because of the low flame speed of the biogas, timing was advanced from 19° BTDC to 23° BTDC. Similarly, Persson and Bartlett (1981) reported an optimum spark advance of 24° BTDC.

Figure 8-18. Diesel Engine Schematic



Source: Busenthur 1986

Excessive diesel fuel (pilot fuel) injection has been reported as the cause of knocking problems in converted diesel engines (Kofoed and Hansen 1981) leading to increased cylinder head pressures and engine temperatures. Maximum engine output and greatly reduced levels of nitrogen oxides and smoke have been obtained using lean mixtures for methane dual-fueled engines (Bro and Pedersen 1977). Saez et al. (1986) also noted a considerable decrease in exhaust contaminants (Bosch Smoke Number) from a biogas/diesel fueled engine bus.

Diesel engines can also be converted to biogas fueled, spark-ignition engines by replacing injectors with spark plugs and the injector pump with a gas carburetor (Persson and Bartlett 1981). The high compression ratio and heavy construction of a diesel engine are desirable features for a spark-ignition biogas engine.

Cogeneration Policies

Electricity produced by cogeneration from biogas can be used in basically four ways:

- 1) isolated consumption for loads on-site,
- 2) parallel consumption on-site and re-sale to a utility grid,
- 3) third party sales, and
- 4) direct sale to a utility grid.

In all cases, design considerations must be given to the metering of power and the protection of loads, metering equipment, generating equipment, and personnel.

When considering sale of electricity to a utility, most of the negotiations will fall under the tenants of the Public Utilities Regulatory Act of 1978 (PURPA). These include:

- o requiring a utility to buy all power from any qualifying facility,
- o exempting a cogenerator from utility commission regulations,
- o blocking utilities from charging excessive rates for backing up a cogenerator, and
- o exempting a cogenerator from the Public Utility Holding Company Act and other federal utility acts.

Although PURPA has been implemented since 1978, several court challenges have and continue to change its exact meaning and intent (Wooster and Thompson 1985). Subsequently, there are as many interpretations of PURPA as there are utilities.

This means that each cogeneration project should be considered site-specific and negotiated as such. Items for negotiation include:

- o metering requirements,
- o buy-back rates,
- o stand-by or backup rates,
- o liability insurance,
- o protection system design,
- o power quality (power factor, etc.),
- o project scheduling (when and who will build system),

- o interconnect ownership (important in third party systems), and
- o utility service charges for operating the system.

The issue of interconnecting with a utility should not be considered trivial. A significant amount of time and effort may be invested in the preliminary discussions, planning, and for implementation of an interconnect system between a cogenerator and the utility (Ross and Walsh 1986, Regulatory Policy Inst. 1983).

Technical requirements for a utility interface are based on reliability and speed for the protection of equipment and personnel. These technical requirements typically are not negotiable with a utility and may be found in the interconnection standards published by the prospective utility. A number of variables will affect the design of an interconnect system including:

Generator type. Generally, electrical generators are basically grouped into two types: synchronous and induction (asynchronous). Induction generators are basically induction motors operated overspeed and are typically used for parallel cogeneration to a utility grid and to plant loads. The inherent protection characteristic of the induction generator in that it requires power from the grid to operate makes it well suited for this application. Synchronous generators require the use of additional components to maintain synchronous operation with the grid.

<u>Condition of the utility grid</u>. The age of the utility grid and the type of grid components within the affected area of a cogeneration project are interrelated with the performance of a cogeneration interface.

<u>Proximity to other power producers</u>. Utilities are concerned with a power phenomena called "islanding" whereby induction power units could conceivably support each other in the event of a grid outage causing mayhem in the system.

<u>Power quality</u>. Utilities will require that measures be taken for the cogenerator to match or exceed the power quality (power factor) of the power supplied to the cogenerator. Many small generators have power factor ratings below 0.80 while many utilities require them to be over 0.90. In most cases, this can be accomplished by using power factor correcting capacitors or similar devices.

Of additional concern are the types and quality of relays for sensing and signaling abnormal conditions in either the interconnect, the grid, or the cogenerator and quickly signaling for disconnection. While some utilities will allow a less-expensive industrial grade relay for this function, most utilities prefer utility grade relays which will quickly signal for disconnection (Reason 1984).

The physical disconnection of the generator from the grid can be accomplished using either a breaker or a contactor. Utilities prefer breakers over contactors because they open faster (within 5 cycles versus 7 cycles), and they provide a greater separation, thus decreasing the possibility of reverse current flow or arching (Ross and Walsh 1986). An example of a cogeneration interconnect with metering and protection systems for a 100 kW system is illustrated in Figure 8-19.

Vehicular Fuel

It is possible to utilize biogas for vehicular fuel (cars, trucks, tractors, loaders, etc.), with the major components of a system consisting of gas cleanup, compression, filling station, and vehicular storage and carburction as shown in Figure 8-20. Accordingly, the critical factors which need to be evaluated for the utilization of biogas as a vehicular fuel include:

Degree of Utilization - A determination must be made on how much fuel biogas can replace on a continuous basis. Because biogas typically must be used within a day or two of generation, there must be a daily consumption pattern established for a vehicular fleet to warrant the conversion of vehicles to biogas and the cost of compression, storage, and refilling systems. Seasonal variations in daily consumptive patterns must be taken into account. Large packaged compressed natural gas systems for vehicular fueling have minimum compression rates of 18 cfm @3600 psi and require a daily consumption of gasoline of 100 gpd to be economically justified (Meloy 1981).

<u>Ouality of Biogas</u>. Biogas quality has a significant impact on the amount of gasoline and diesel fuel equivalents per cylinder of compressed gas. The bulky nature of biogas versus gasoline and diesel creates some range problems due to fuel storage. Removal of CO_2 and other inert gases will increase the fuel equivalence for a cylinder of gas. Because of the corrosive nature of H₂S and water on compression, storage, and fueling systems, the biogas would have to be relatively clean.

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Figure 8-19. 100 kW Interconnect System



NITS/05

Negative Sequence

Figure 8-20. Vehicular Fuel System



Source: Born 1982

<u>Vehicle Range</u>. Consideration must be given to take into account the gasoline and diesel fuel equivalents per cylinder of compressed gas and the physical limits associated with mounting the storage cylinders on a vehicle. The number of hours of tractor operation or the number of potential miles of vehicle travel area direct function of storage cylinder volume. Consideration also must be given to refilling schedules, filling station location, and system safety.

Regarding fuel economy, Henrich and Phillips (1983) suggest a rule-of-thumb equivalence of 100 SCF of pure methane per one gallon of gasoline. A 372 SCF (2400 psi) cylinder (actual volume of 16 gallons) of pure methane would have a gasoline equivalent of roughly 3.7 gallons. Four cylinders of 60% methane biogas compressed to 2900 psia corresponds to about 10.6 gallons of diesel fuel and allows for tractor operation up to 3.5 hours under full load (80 HP) and 7 hours under 40% load (Fankhauser <u>et al.</u> 1983).

Engine Conversion. Although conversion kits are available for dual fuel (biogas or gasoline/diesel) operation, allowances must be made for losses in engine performance (see Engines section above), including decreased acceleration and fuel economy. Diesel tractor conversions have been successful; however, problems were encountered with freezing of CO_2 while the gas was expanded for use from the compressed gas cylinders. While the torque and brake power characteristics of the

tractor were comparable with diesel fuel only, there was some difficulty with maintaining constant engine speed at low partial loads (Fankhauser <u>et al.</u> 1983). Likewise, conversion for a gasoline automobile engine to compressed natural gas has been shown to reduce maximum power by 10-15% (Born 1982 and Evans <u>et al.</u> 1986).

<u>Equipment</u>. Commercial systems have been operated for the compression, storage, and fueling of small fleets of vehicles on methane (EMCON 1983). Smaller refuel stations of 3 cfm @2400 psi are available; however, no operational data are available on performance or economics (OMC 1982).

Refill stations fit into two categories: 1) cascade or rapid fill and 2) timed fill. While a cascade fill system is more expensive, it will refuel a vehicle in 3-5 minutes. A timed fill system requires more planning to allow for vehicles to be fueled usually overnight over a 14 hour period. A natural gas refueling station is shown in Figure 8-21. The cost of a refueling station is in the range of \$50,000 (1983) for a system providing compressed methane with the equivalent energy content of 250 gallons of gasoline per day (Henrich and Phillips 1983).



Figure 8-21. Vehicular Fuel Refueling Station

Source: Wright 1982

Vehicle storage requires the use of Department of Transportation approved gas cylinders, most with a capacity of 372 SCF of gas at 2400 psi and the dimensions of 9.25 inches in diameter and 55 inches in length (16 gallons). Tanks should include pressure and heat fusible rupture discs for controlled gas release under stressed conditions.

Gasoline engine conversion kits for propane and compressed natural gas are commercially available from a number of domestic and foreign suppliers (EMCON 1983). Some systems allow for dual fueling by mounting the fuel gas carburetor between the existing carburetor and the intake manifold. These can be switched between gasoline and biogas by flipping a switch inside the vehicle. The cost of converting a car or truck to compressed methane averages \$1,500 per installation including labor (Henrich and Phillips 1983 and Adams 1986).

As previously discussed, diesel engine conversion involves a more radical modification which allows for simultaneous injection of some diesel fuel (pilot fuel) to aid in ignition of the biogas which is introduced with the intake air to the engine. There are no known commercial systems for diesel conversion to biogas for vehicular use.

<u>Problems</u>. A number of problems have surfaced in the conversion of a fleet of gasoline vehicles to methane (EMCON 1983); including:

- o loss of power (10-20%),
- o difficulty in starting, particularly in cold weather,
- o gas leaks at filling stations, vehicle storage tanks, and carburctors,
- o corrosion of equipment from biogas,
- o limited range,
- o re-fueling scheduling and capacity, and
- o driver dissatisfaction.

Pipeline Ouality Gas

To maintain the high heating value and purity standards for pipeline quality gas, biogas must be treated to meet the following standards (Cairns and Pincince 1984):

- o water levels less than 7 lbs/MMSCF (0.11 mg/L),
- o hydrogen sulfide levels less than 2.7 ppm, and
- carbon dioxide and nitrogen levels sufficiently low
 (3% or less) to provide gas energy contents of 975
 Btu/SCF or greater.

These gases, particularly landfill gases, may also contain other trace elements that are not acceptable to the local natural gas utility for purchase (GRI 1982). A number of gas treatment methods for the removal of these components are detailed in Chapter 5. Besides gas quality, other considerations for resale of pipeline quality biogas include meeting pipeline pressures and maintaining flowrates to the purchaser.

Environmental Considerations

All methods of biogas utilization should be evaluated for environmental impact on the site surroundings. Most of these considerations are associated with the technology rather than the fuel and are regulated by existing state and federal statutes. These include the emission of nitrogen oxides and smoke particulates from combustion systems. Noise pollution from the operation of engines and compressors may also require site-specific modifications.

Fuel specific environmental concerns may include the proper handling and disposal of chemicals and compounds used for biogas clean-up. Handling of common materials such as anti-freeze solutions and engine oils should also receive special attention.

Any biogas utilization system should be reviewed early in the planning stages for environmental compliance with the appropriate state agencies.

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CHAPTER 9

INSTRUMENTATION AND CONTROLS FOR BIOGAS EQUIPMENT

Introduction

There are a number of measurements that are desirable for designing, monitoring, and controlling both the anacrobic processes which produce biogas and the systems which recover the energy from the biogas. The equipment required will vary depending on the source of the biogas (digester versus landfill) as well as the complexity of the utilization system. Some of these measurements are performed continuously, but some portable and laboratory equipment is essential. There is a wide variety of equipment available off-the-shelf which can be used to measure all parameters of interest for gas production and quality. The operation and maintenance costs of such equipment can be high due to the corrosive nature of the gases. A list of suggested equipment and processes for almost every measurement derived during anaerobic digestion is provided in the U.S. Environmental Protection Agency Process Design Manual (USEPA 1979c). Price (1981) and EMCON (1980) have also reviewed basic measurement processes, and the Sierra Monitor Corporation summarizes guidelines of proper gas monitoring management for wastewater systems. Based on these reviews and practical experiences, this chapter provides an overview of equipment and strategies needed for proper biogas monitoring and control.

Gas Composition

Gas composition (%CH₄, %CO₂, %N₂, %O₂, %H₂S) is a useful parameter for energy and mass calculations and for monitoring the relative health of the anaerobic process. Data on composition is needed for design of clean-up equipment, burners, and engine modifications such as compression ratio and spark advance. Variations in gas composition can indicate problems in digester operation or depletion of gas being produced by a landfill. Natural gas distributors purchasing pipeline quality biogas may require periodic or continuous measurements of gas composition. Composition can be measured with simple, hand-held instruments or complex continuous monitoring equipment. The more common instruments used for determination of biogas composition are briefly described in the following sections.

<u>Diffusion Tube</u>. Chemical sensing diffusion tubes are hand-held instruments that determine biogas composition by measuring the chemical reaction of a single constituent in the gas with material in the tube. These devices can be used to measure most all of the constituents of biogas including water vapor, but different tubes must be used for each constituent. In addition, the tubes are designed for a specific concentration range, and thus, the appropriate tube must be used to measure a specific range of concentration. The expendable tubes are packed with a material that changes color when exposed to a specific gas. Gas is pulled through the tube by a bellows or pump which determines the quantity of the gas sample. As the gas is pulled through the tube, the constituent being measured reacts with the material in the tube and causes the material to change color. The exterior of the tube is calibrated such that the point at which the color change stops determines the quantity of a particular constituent in the gas. These devices are manufactured by a number of companies.

<u>Chemical Absorption</u>. Chemical absorption analyzers such as the one manufactured by Bacharach Instruments are hand-held devices and are typically used to determine the concentration of CO_2 and O_2 in boiler exhaust. These devices can be used to determine the approximate composition of biogas by determining the concentration of CO_2 and O_2 in the biogas and assuming the balance of the gas is CH_4 . A separate tester is used for CO_2 and for O_2 .

A quantity of gas is pulled into the analyzer with a hand pump and the fluid in the analyzer absorbs a portion of the gas constituent being analyzed. The absorption of a portion of the gas causes the pressure inside the analyzer to fall below atmospheric. The atmospheric pressure on the outside of the analyzer pushes on a rubber diaphragm in the analyzer wall and causes the fluid level in the analyzer to rise. The height of the fluid rise determines the concentration of the specific constituent in the biogas.

Gas Chromatograph. The best equipment for measuring gas composition is an on-line chromatograph. This instrument contains a packed column (tubing filled with absorbent material) which serves to separate the different components of the gas on the basis of molar weight and other molecular properties. The individual components of the exiting gas are measured by a detector (preferably a thermalconductivity detector since flame ionization detectors are not useful for measuring carbon dioxide). The output from the detector is plotted as a function of time, and component concentrations are calculated from the areas under each output peak.

Mass Spectrometer. Another instrument capable of on-line gas composition analysis is the mass spectrometer. The principal of operation is similar to that of the gas chromatograph except that detection of the constituents separated by molecular weight differences is accomplished by electronic detection. However, this instrument is prohibitively expensive for most applications.

Gas Caloric Value

The caloric value of the gas is the most important parameter as it indicates the heat value of the gas. The caloric value must be determined to compute the Wobbe Index for a specific burner orifice (See Chapter 8). This value can be used to directly control any blending operations, or to control variable burner orifices to ensure a constant heat input to the process. The caloric value is typically computed from the percentages of combustibles in the biogas, but equipment can be used to determine this parameter.

<u>Continuous Recording Calorimeter</u>. In order to determine the caloric value of biogas, a gas sample of known volume is burned under strictly controlled conditions in a calorimeter, where heat developed by combustion is measured (ASTM D-1826). Accuracies of $\pm 1.5\%$ of full scale can be expected; however, the response of the calorimeter is slow.

Gas Density

Measurement of gas density alone is made infrequently, since this parameter can often be computed from data from other analyses such as gas chromatography. The density of the gas is also needed to compute the Wobbe Index for a specific burner.

<u>Balance Detector</u>. The density of the gas can be determined by the use of a balance detector cell which is the pneumatic analog of a Wheatstone bridge. In this method, a reference gas and the sample gas are passed through the cell. The temperature differential created is measured with thermocouples in the device, and related to the difference in the density of the reference gas and the unknown density. Because the process has a complex purging system, analysis of wet or dirty biogas or biogas from long sample lines may be difficult.

Gas Flow

One of the more basic biogas instrumentation requirements is that of gas flow. Gas production from a digester is an indication of performance and is directly related to the general "health" of the anaerobic system. Biogas being blended with an auxiliary fuel must be controlled and thus the flow rate must be known. The total quantity of biogas supplied to a natural gas pipeline must be recorded to establish the basis for payment for the fuel. There are a number of methods available to measure gas flow which are briefly described in the following sections:

Rotating Vane Meter. The most common method of measuring gas flow is by the use of a rotating vane gas meter such as those used on natural gas wells. The gas flowing through the meter causes internal vanes to rotate which in turn move the dials on the front of the meter. These meters are typically totalizing types that indicate the total quantity of gas produced, but can be modified to read rate if needed. Electronic pick-offs can be added for automatic recording of data.

Maintenance of rotating meters in biogas systems can be a problem due to corrosives in the biogas. Care must be taken to insure that the lubricating oils for the meter do not become contaminated, and that the oil is changed on a periodic basis. These meters should be removed and cleaned if the system is not operated for an extended period of time.

Differential Pressure. Another common method for determination of biogas flow is detecting the differential pressure across a fixed (normally concentric) orifice or venturi which is installed between flanges in the gas piping. The flow rate is calculated from the differential pressure using a discharge factor for the measuring device. Measurements made at approximately 100 in. of water column differential pressure are the most accurate. This high pressure occurs if the gas is being pumped from the digester. When the digester pressure governs flow, differential pressures of approximately 1 in. water column are used, making the measurement more difficult and less accurate.

Pitot Tube. The pitot tube used in conjunction with a manometer or a Magnehelic gauge, is the most common method of measuring velocity. Accuracies of $\pm 15\%$ may be achieved with the pitot tube. A pitot tube is a probe with a 90° bend at the end which is inserted into the gas stream such that the open end at the tip of the bend faces directly into the gas flow. The dynamic pressure measured with the probe and the static head measured at the wall of the gas pipe are used in Bernouli's equation to determine gas velocity. Flow rates can be determined by utilizing the continuity equation which states that the flow rate equals the average gas velocity times the area normal to the flow. However, when these devices are subjected to a very wet, corrosive gas, maintenance requirements can be very high. This fact also makes device material selection very important.

<u>Thermal Mass Flow Meter</u>. A thermal mass flow meter measures the flow rate by determination of the cooling rate of the fluid passing the heated probe. Another type of device heats a portion of the gas stream and correlates mass flow to the rate of heat transfer to the gas. Both designs must be calibrated for the thermal properties of the specific gas being measured.

Selection of materials for biogas flow measurement equipment is critical since parts of the equipment will be exposed to the gas stream (See Chapter 4). Hydrogen sulfide and other corrosives (particularly those found in biogas from landfills) can cause corrosion problems.

Flow monitoring equipment must be accurately calibrated before operation and at periodic intervals after the start of operation. Erosion of surfaces or plugging by contaminants can cause changes in output. Calibration curves must be corrected for differences in the density of air and biogas unless the equipment is calibrated using biogas or a synthetic biogas $(CH_4/CO_2 \text{ mixture})$.

Pressure

Pressure can be used to control system operation such as the starting and stopping of an engine or the power output of the engine. It is also an indicator of the health of the digester or landfill in that low pressure can be used to indicate a lack of biogas production. On high pressure systems which use a compressor, pressure data can be used to control compressor operation and indicate its performance. The type of instrumentation required depends on the operating pressure of the system.

Low Pressure Systems. Low pressure systems which operate at a maximum of approximately 1 psig (27.7 inches water column) typically use manometers for pressure measurement. A manometer indicates pressure in inches of water column (in. w.c.) by the difference in level of the water in a "U" shaped tube with one end connected to the system and the other end open to atmosphere. Gauges are also available for reading pressure in inches water column. The gauges can be combined with electrical contacts for the starting and stopping of equipment. The simplest pressure measurement device is the inclined manometer. The Dwyer Magnehelic differential pressure gauge is an alternative to the manometer. These gauges are accurate to $\pm 2\%$ of scale (EMCON 1980), but need to be calibrated prior to each use.

<u>High Pressure Systems</u>. Standard pressure gauges are used for high pressure systems. Materials selection is not as critical with these components since H_2S and other corrosives are usually removed before compression.

Ambient Exposure Potential

Biogas presents a number of toxicity and explosive hazards due to CH_4 , H_2S , and other constituents. The details of these hazards are discussed in Chapter 10. Gas concentrations which present a hazard to personnel can be detected through the use of a <u>diffusion tube</u> and by obtaining a gas sample and analyzing the sample with a <u>gas chromatograph</u> or <u>mass spectrometer</u>. There are several devices available to actively monitor for biogas in area's where gas buildup could occur.

<u>Combustible Gas Sensors</u>. These devices are remote catalytic type sensors which consist of a heated catalytic element which is exposed to the ambient air, and a similar inert reference element. A collar protects the reference element from the ambient conditions. When the element is exposed to a flammable gas its temperature rises above that of the reference element and the differential is sensed. The rise in temperature of the element is attributed to the catalytic oxidation of the gas by the element which produces heat. A flame arrester will provide operating safety with fast sample diffusion.

<u>Metal Oxide Semiconductor (MOS)</u>. These hydrogen sensitive electronic sensors can be used for the detection of various hydrogen based gases including CH_4 , H_2 , and H_2S . The sensor works on the principle of ionadsorption whereby oxidation/reduction reactions at the sensor surface change the conductive properties of the material. This effect can then be measured as a change in the resistance correlated to a gas concentration.

Combustible gas sensors utilize this technology; however, they are often prone to drift and must be calibrated frequently. While some sensors are designed to monitor only a particular gas, they tend to indicate the cumulative presence of all hydrogen containing gases.

<u>Electrochemical</u>. This series of sensors incorporate the use of ion selective membranes and/or electrolytes to selectively sense a single gas component. They work on the principle of ion transport across a membrane filter to react with an electrolyte. The change in the electropotential between the measuring cell and a reference cell is correlated to the gas concentration.

These sensors have been used for monitoring a variety of gases including H_2 , CO, CO₂, and H_2S . Like MOS sensors, they require frequent calibration and maintenance.

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CHAPTER 10 BIOGAS SAFETY CONSIDERATIONS

Introduction

This chapter discusses the major safety aspects of biogas installations. There are three major dangers to property and personnel that must be considered: toxicological dangers due to poisonous and asphyxiating gases, fire and explosion dangers due to combustible gases, and physical dangers due to operation of the system at both positive and negative pressures. The specifics of each of these three dangers will be presented first. Recommendations for prevention of accidents will be discussed later since accident prevention techniques often apply to more than one danger.

Toxicological Dangers

The toxicological dangers of biogas are essentially a combination of the individual component gases: methane, carbon dioxide, hydrogen sulfide, and methyl mercaptan. A summary of these characteristics are presented in Table 10-1. Data on the color and odor characteristics which could be used to identify the presence of the gases are presented in the table. The minimum identifiable odor (MIO) listed is the concentration level in parts per million at which the gas can be detected.

The Threshold Limit Values (TLV's) for various industrial hazardous chemicals are established by the American Conference of Governmental Industrial Hygienists in Cincinnati, Ohio. The definitions of the two values shown in the Table 10-1 are as follows:

<u>Threshold Limit Value - Time Weighted Average (TLV-TWA)</u> is the timeweighted average concentration for a normal 8-hour workday and 40-hour workweek, to which nearly all workers may be repeatedly exposed, day after day, without adverse effect.

<u>Threshold Limit Value - Short Term Exposure Limit (TLV-STEL)</u> is the 15 minute time weighted average exposure which should not be exceeded at any time during a work day even if the eight-hour time weighted average is within the TLV.

The table also indicates the major physiological effects of each of the gases which compose biogas. It can be concluded from the table that biogas should be considered a poisonous gas since it contains more than 10 ppm of hydrogen sulfide. As noted in the table, there is no TVL established for methane. Methane causes death by asphyxiation by reducing the level of oxygen available for breathing. At sea level, the minimum acceptable oxygen concentration level is 18% by volume. Usually, a high methane concentration will cause an explosion danger before it causes a danger from lack of oxygen.

A brief summary of major symptoms of overexposure to the components of biogas is presented in Table 10-2. The purpose of the table is make plant management aware of the warning signs of gas leaks.

Table 10-1. Toxicity Characteristics of Biogas Constituents

<u>Gas</u>	<u>Color</u>	<u>Odor</u>	MIO (1) (ppm)	TVL TWA (2) (ppm)	TLV STEL(3) (ppm)	Physiological <u>Effects</u>
Methane	None	None	-	(4)	(4)	Asphyxiant
Hydrogen Sulfide	None	rotten egg	0.7	10	15	Poison
Methyl Mercaptan	None	strong garlic	0.5	0.5	(4)	Poison
Carbon Dioxide	None	None	-	5,000	30,000	Asphyxiant

(1) MIO - Minimum Identifiable Odor

(2) TLV-TWA - Toxic Limit Value - Total Weighted Average

(3) TLV-STEL - Toxic Limit Value - Single Total Exposure Limit

(4) Not Established

Source: ACGIH 1987

Table 10-2. Typical Symptoms of Overexposure to Biogas Constituents

Gas

Symptoms

Carbon Dioxide

Headache, Dizziness Restlessness, Sweating

Hydrogen Sulfide

Methyl Mercaptan

Nausea Convulsions

Eye Irritation Convulsions

Source: ACGIH 1987

ANY PERSONNEL WHO EXHIBIT ANY OF THE SYMPTOMS LISTED SHOULD BE CHECKED BY MEDICAL PERSONNEL AND THE SYSTEM SHOULD BE CHECKED FOR ANY LEAKS.

Flammability Dangers

The flammability characteristics of the components of biogas are presented in Table 10-3. Carbon dioxide is not combustible and thus the only characteristic applicable to this gas is specific gravity. The significance of each of the characteristics provided is as follows:

<u>Vapor Density</u>. The vapor density is the ratio of the density of the gas to the density of air at the same temperature and pressure. As shown in Table 10-3 methane is lighter than air and will tend to collect near the ceiling of an enclosed building. Therefore, it is important to adequately vent a building containing biogas equipment. The other gases are heavier than air and would tend to collect in any sumps or low areas near the biogas system.

<u>Lower Explosive Limit</u>. The lower explosive or flammability limit is the minimum concentration of a combustible gas in air which sustains combustion. If the concentration of the gas is below this level, combustion will not be sustained since there is insufficient fuel to maintain burning.

<u>Upper Explosive Limit</u>. The upper explosive or flammability limit is the maximum concentration of a combustible gas which sustains combustion. If the concentration of the gas is above this level, combustion will not be sustained since there is insufficient air to maintain burning.

<u>Autoignition Temperature</u>. The autoignition temperature is the temperature at which combustion will be initiated without the addition of source of ignition such as a spark. The concentration of the combustible must be within the flammability range.

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<u>Gas</u>	<u>Specific Gravity</u>	Explosive <u>Lower</u> %	Limits <u>Upper</u> %	Autoignition <u>Temperature</u> %
Methane	0.5	5	15	650
Hydrogen Sulfide	1.2	4	46	550
Methyl Mercaptan	1.66	4	22	(1)
Carbon Dioxid c	1.5	None	None	None

Table 10-3. Flammability Characteristics

(1) Data not available

Physical Dangers

There are a number of physical dangers associated with biogas systems that are common to almost all industrial systems. These dangers include open-top sumps, low hanging pipes, slippery floors, etc. The major physical dangers associated with biogas systems due to their operational characteristics are caused by positive and negative system pressures.

<u>Positive Pressure Dangers</u>. Systems operating at low pressure (less than 30in. water) present only minor dangers from pressure. An overpressure situation could cause a slow escape in areas where personnel may be injured. However, systems with compressors can present severe problems if a high pressure line ruptures.

<u>Negative Pressure</u>. Negative pressure can occur when a digester is drained without opening a vent to allow air to fill the void space left by the draining liquid. The vacuum pressure created can collapse the roof or walls of a digester causing damage to personnel and property. The mixture of air and biogas could fall within the explosive limits resulting in a potentially dangerous situation.

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Safety Equipment

A list of safety equipment recommended for installation at all plants is presented in Table 10-4. The details of the instrumentation are discussed in Chapter 9. A list of the manufacturers of this equipment is included in the Appendix.

Although commercial low-pressure relief valves and vacuum breakers are available, experience has shown that water contained in the biogas can tend to jam mechanical equipment. A water relief valve can eliminate this problem. Care must be taken to insure that the water levels in the valve are maintained at the proper level. A rupture disk fabricated from a non-metallic material can eliminate problems with corrosion of metallic vacuum breakers.

Recommended Safety Practices

A list of recommended safety practices is presented in Table 10-5. These practices address safety hazards from toxicological, flammability, and pressure problems. As discussed earlier, some of the recommendations apply to more than one hazard. It is recommended that a plant design be analyzed to assure that the design meets all the criteria identified in the list.

Table 10-4. Recommended Safety Equipment

Safety_Device	Function
Pressure Relief Valve	Prevents injury to personnel due to rupture and prevents leakage of biogas due to overpressurization of seals.
Vacuum Breaker	Prevents collapse of digester walls and roof during draining of liquid in digester.
Combustible Gas Sensor	Detects leak of biogas which could become an explosion hazard.
Hydrogen Sulfide Sensor	Detects a build-up of H_2S which could become a toxicological danger to personnel.

Table 10-5. Safety Precaution Check List for Biogas Systems

- 1. Prevent gas discharge in confined areas with gas-tight pipes and valves and safety relief valve discharges to building exterior or open areas.
- 2. Purge air from biogas delivery lines before operation of combustion equipment since exclu 1 air will insure the biogas concentration is above the upper flammability limit.
- 3. Install flame traps in lines near combustion equipment to prevent flashback into the digester or storage tank.
- 4. Ensure adequate ventilation around all gas lines.
- 5. Install a vent at the ridge line of all buildings to allow escape of gases such as methane which are lighter than air.
- 6. Slope all gas lines 1:100 and install a water trap at the low point to prevent blockage of lines by the water condensed from the gas.
- 7. Protect gas lines from freezing which can result in damage to the line and blockage of the line by frozen water condensed from the gas.
- 8. Remove any potential source of sparks or flame from areas where biogas is present.
- 9. Have one or more carbon dioxide or halon fire extinguishers in the area where biogas is present.
- 10. If the gas is compressed, use storage tanks with a minimum design pressure of 2,400 psig.
- 11. Install safety relief valves to prevent overpressurization of both high and low pressure systems.
- 12. Install vacuum breakers on all systems connected to digesters to prevent injury to personnel and damage to equipment due to draining of digester liquid.
- 13. Install combustible gas monitors and hydrogen sulfide detectors to detect leaks of gases in any area where personnel may be injured.
- 14. Do not allow smoking in the area.
- 15. Incorporate explosion proof lighting and electrical service when biogas exposure is considered likely.
- 16. Post signs indicating an explosion hazard near the biogas equipment and storage. Also post no smoking signs.

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APPENDIX A

ALPHABETICAL LISTING OF EQUIPMENT SUPPLIERS

A-C Compressor Corporation 1126 South 70th Street West Allis, WI 53214 414-475-4305

Advanced Industrial Technology Corp. P.O. Box 555 T Lodi, NJ 07644 Industrial Gas Systems 201-265-1414

Advanced Manufacturing Systems, Inc. 110 Technology Parkway Technology Park Atlanta Norcross, GA 30092 404-448-6700

Aero Tech Labs, Inc. Spean Road Industrial Park Ramsey, NJ 07446 201-825-1400

Aerzen USA Corporation 313T National Rd. Exton Industrial Park Exton, PA 19341 215-524-9870

Airco Industrial Gases 575 Mountain Ave. Murray Hill, NJ 07974 201-464-8100

Airovent, Inc. Gartmer Equipment Company P.O. Box 206 Syracuse, NY 13208 315-476-8321

Alemite & Instrument Div. Stewart - Warner Corp. 1826 Diversey Pkwy. Chicago, IL 60614 312-883-6000 Alphasonics, Inc. 12010 Hwy. 290 W., Ste 200-C Austin, TX 78737 512-288-3661

American Yazaki Corp. 13740 Omega Rd. Farmers Branch, TX 75244 214-385-8725

Applebee-Church, Inc. P.O. Box 80186 - Chamblee Atianta, GA 30341 404-451-2747

Applied Cogeneration 11341 San Fernando Rd. San Fernando, CA 91340 818-896-7443

Applied Thermal Systems, Inc. P.O. Box 101493 Nashville, TN 37210 615-366-0221

Automatic Switch Co. 50-60 Hanover Rd. Florham Park, NJ 07932 800-972-2726

Babock & Wilcox, Industrial Power Generation Div. 4282 Strausser Street NW P.O. Drawer 2423T North Canton, OH 44720 216-497-6223

Bauer Compressors, Inc. 1328 W. Azalea Garden Rd. Norfolk, VA 32502 804-855-6006 The Bigelow Co. 142 River St. P.O. Box 706-T New Haven, CT 06503 203-772-3150

Boulder Associates, Inc. 473 E. Church Rd. P.O. Box 88 King of Prussia, PA 19406 215-277-7730

Bradford-White International Ltd. 2401 Ellsworth St. Philadelphia, PA 19146 215-546-3800

Calvert Environmental Equipment Co. 5191-T Sante Fe St. San Diego, CA 92109 619-272-0050

Carolina Technical Representatives, Inc. P.O. Box 1115 Matthews, NC 28105 704-847-4494

CECA, Inc. Adsorption Technology 4150 S. 100th East Ave., Ste 300 Tulsa, OK 74146 313-737-4591

CH2M Hill Solid Waste Specialists P.O. Box 4400 Reston, VA 22090 804-471-1441

Chemical Design, Inc. 285 Market St. Box 513-T Lockport, NJ 14094 716-433-6744

Coen Company, Inc. 1510-12 Rollins Rd. Burlingame, CA 94010 415-697-0440 Connelly-GPM, Inc. 200 S. Second Street Elizabeth, NJ 07206 312-247-7231

Continental Products, Inc. P.O. Box 418165 M Indianapolis, IN 46241 317-241-4748

Coppus Engineering 344 Park Ave Worcester, MA 01610 617-756-8393

Corken International Corp. P.O. Box 12338 Oklahoma City, OK 73157 405-946-5576

Distral Energy Corporation 1125 NE 7th Ave. Dania, FL 33004 305-920-8100

Dresser Measurement Dresser Industries, Inc. P.O. Box 42176 - TR Houston, TX 77242 713-972-5000

Duall Industries, Inc. 760 S. McMillan St. Owosso, MI 48867 517-725-8184

Ecolaire, Inc. 2 Country View Rd. Malvern, PA 19355 215-647-9900

Edwards Engineering Corp. 101-A "Alexander Ave. Pampton Plains, NJ 07444 800-526-5201 EMCON Assoc. 1941 Ringwood Ave. San Jose, CA 95131 408-275-1444

EnerTech Corp. 201 Allen Rd. Atlanta, GA 30328 404-432-1234

Enerquip, Inc. Dept. M P.O. Box 368 611 North Rd. Medford, WI 54451 715-748-5888

Enterra Instrumentation Technologies 251-ET Welsh Pool Rd. Exton, PA 19341 215-363-5450

Ergenics 681-T Lawline Rd Wycoff, NJ 07481 201-891-9103

ESCOR, Inc. 550 Frontage, #208 Northfield, IL 60093 312-501-2190

Fermont 141 T North Ave. Bridgeport, CT 06606 203-366-5211

Fischer & Porter Company 51 Warminster Rd. Warminster, PA 18974 215-674-6000

Flaregas Corporation 100 Airport Executive Park Spring Valley, NY 10977 914-352-8700

The Foxboro Company 86 Neponset Ave: Foxboro, MA 02035 617-543-8750 Friedrich Air Conditioning & Refrigeration Co. 4200 N. Pan Am Expwy. San Antonio, TX 78295 512-225-2000

Getty Synthetic Fuels, Inc. P.O. Box 1900 Long Beach, CA 90801 213-739-2100

Groth Equipment Corp. P.O. Box 15293 1202 Hahlo Houston, TX 77020 713-675-6151

Hamworthy USA, Inc. Pump & Compressor Div. 10555 Lake Forest Blvd., Ste. 1 F-T New Orleans, LA 70127 504-244-9074

Hedland Div. of Racine Federated, Inc. 2200 South St. Racine, WI 53404 800-433-5263

Henderson Sales & Service, Inc. P.O. Box 830876 Richardson, TX 75083 214-234-3226

Hydronics Engineering Corp. Godwin Ave. P.O. Box 179-T Midland Park, NJ 07432 210-444-4376

Industrial Marketing Assoc. 11642 Knott Ave., Suite 5 Garden Grove, CA 92641 714-836-4706

Industrial Gas Systems 13477 Prospect Rd. Dept 207 Cleveland, OH 44136 904-445-4200 Industronics, Inc. 489 Sullivan Ave. South Windsor, CT 06074 203-289-1551

Industry Hills SCS Engineers 4014 Long Beach Blvd. Long Beach, CA 90807 213-426-9544

John Zink Co. 4401 S. Peoria Tulsa, OK 74105 918-747-1371

Kemion Products & Development Corp P.O. Box 14666-TR Houston, TX 77021 713-747-5020

Kennedy Van Saun Corp. P.O. Box 500 Danville, PA 17821 717-275-3050

Kurz Instruments, Inc. 2411 Garden Rd. Monterey, CA 93940 800-424-7356

Linde Specialty Gases, Union Carbide Corp. P.O. Box 6744-T Somerset, NJ 08873 800-982-0030

Matheson Gas Products, Inc. 30-T Seaview Dr. Secaucus, NJ 07094 201-867-4100

Microtrol Environmental Systems, Inc. One Oscar Hammerstein Way P.O. Box 426-T New Hope, PA 18738 215-862-9465 Midwesco Energy Systems 7720 Lehigh Ave. Dept. T115 Niles, IL 60648 312-966-2150

Monroe Environmental Corp. 11 Port Ave. P.O. Drawer 806-T Monroe, MI 48161 800-992-7707

Natco P.O. Box 1710 Tulsa, OK 74101 918-663-9100

Nelson Filter P.O. Box 280 Stroughton, WI 53589 608-873-4300

Neotronics N.A., Inc. P.O. Box 370 2144 Hilton Dr. SW Gainesville, GA 30503 404-535-0600

O'Brien Energy Systems Green Street & Powerhouse Place Downington, PA 19335 215-269-6600

Parker Engineering & Chemicals, Inc. Dept. G 3077 McCall Dr. P.O. Box 81226 Atlanta, GA 30366 404-458-9131

Perennial Energy Inc. Route 1, Box 645 West Plains, MO 65775 417-256-2002

Pierburg Metering Systems, Inc. 41-T Vreeland Ave. Totowa, NJ 07512 201-785-0136 Power Flame, Inc. 2001 S. 21st Street Parsons, KS 67357 316-421-0480

Process & Cyrogenic Services, Inc. 2170-T Old Oakland Rd. San Jose, CA 95131 800-826-3062

Public Service Electric & Gas Company Research Corp. P.O. Box 570 T-16A Newark, NJ 07101 201-430-7000

Resource Systems, Inc. B-6 Merry Lane East Hanover, NJ 07936 201-884-0650

Scientific Gas Products Ashland Chemical Co. 2330-T Hamilton Blvd. South Plainfield, NJ 07080 201-344-6998

SCS Engineers 11260 Roger Bacor Dr. Reston, VA 22090 804-471-6150

Semblex 1635 W. Walnut Springfield, MO 65806 417-866-1035

Sierra Monitor Corp. 1991-T Tarob Court Milpitas, CA 95035 408-262-6611

Spectra Gases, Inc. 3033 Industry St. Oceanside, CA 92054 800-932-0624 Stahl, Inc. Farrier Products Div. Church Rd. & Derry Ct. Box M-34A York, PA 17405 717-767-6971

Stevens Electric Company, Inc. 810-812 N. Main St. Memphis, TN 38107 800-874-5909

Super-Ice Corp. P.O. Drawer 783 San Leandro, CA 94557 415-483-1778

Syn Fuels 1221 Ave of the Americas New York, NY 10020 212-512-3916

Technotherm Corporation 5508 West 66th Street South Tulsa, OK 74131 918-446-1533

ThermaFlo Marketing Dept. 3640 Main St. Springfield, MA 01107 800-556-6015

Turbo Refrigerating Co. P.O. Box 396-T Denton, TX 76202 817-387-4301

Turbosystems International 7 Northway Lane Latham, NY 12110 518-783-1625

U.S. Turbine Corporation 7685 South State Route 48 Dept. A Maineville, OH 45039 513-683-6100
Virginia Technical Associates, Inc. 7202 Impala Drive Richmond, VA 23228 804-266-9654

Vooner Equipment Co., Inc. Dept. T, P.O. Box 240360 4725 Stockholm Court Charlotte, NC 28224 800-345-7879

Vulcan Waste Systems, Inc. 300 Huron St. P.O. Box 4030 Elyria, OH 44036 717-822-2161

Waste Management, Inc. 3003 Butterfield Rd. Oak Brook, IL 60521 312-572-8800

Waukesha Engine Division Dresser Industries, Inc. 1000 West St. Paul Ave. Waukesha, WI 53188 414-547-3311

Wehran Engineering 666 East Main St. Middletown, NY 10940 914-343-0660

Wittemann - Hasselberg, Inc. 2 Commerce Bivd. Palm Coast, FL 32037 904-455-4200

Wormser Engineering, Inc. 225 Merrimac Street Woburn, MA 01801 617-983-9380

APPENDIX B

LISTING OF COMPANIES BY PRODUCT OR SERVICE

GAS RECOVERY

Getty Synthetic Fuels, Inc. John Zink Co. Wehran Engineering

GAS PURIFICATION

Advanced Industrial Technology Corp. Calvert Environmental Equipment Co. Chemical Design, Inc. Connelly-GPM, Inc. Duall Industries, Inc. Ergenics Hydronics Engineering Corp. Industrial Gas Systems Microtrol Environmental Systems, Inc. Morrow Environmental Corp. Natco Nelson Filter Process & Cyrogenic Services, Inc. Resource Systems, Inc.

COMPRESSORS

A-C Compressor Corporation Aerzen USA Corporation Airovent, Inc. Bauer Compressors, Inc. Corken International Corp. Ergenics Hamworthy USA, Inc. Henderson Sales & Service, Inc. Kemlon Products & Development Corp Vooner Equipment Co., Inc. Wittemann - Hasselberg, Inc.

CONSULTING

Advanced Manufacturing Systems, Inc. Industry Hills O'Brien Energy Systems Perennial Energy Inc. SCS Engineers Vulcan Waste Systems, Inc. Waste Management, Inc. Wormser Engineering, Inc. CH₂M Hill

BURNERS

Babcock & Wilcox Coen Company, Inc. Cleaver Brooks EnerTech Corp. Power Flame, Inc.

BOILERS

Applebee-Church, Inc. Applied Thermal Systems, Inc. Bradford-White International Ltd. Carolina Technical Representatives, Inc. Technotherm Virginia Technical Associates, Inc.

COGENERATION

Applied Cogeneration Automatic Switch Co. The Bigelow Co. Boulder Associates, Inc. Caterpillar Coppus Engineering Cummins Engine Distral Energy Corporation Ecolaire, Inc. Energuip, Inc. Ford Fermont Industronics, Inc. Midwesco Energy Systems O'Brien Energy Systems Parker Engineering & Chemicals, Inc. Perennial Energy, Inc. Stahl, Inc.

Stevens Electric Company, Inc. Technotherm Corporation Turbosystems International U.S. Turbine Corporation Vulcan Waste Systems, Inc.

ABSORPTION CHILLERS

American Yazaki Corp. Continental Products, Inc. Edwards Engineering Corp. Friedrich Air Conditioning & Refrigeration Co. Super-Ice Corp. ThermaFlo Marketing Dept. Turbo Refrigerating Co.

INSTRUMENTATION AND HANDLING

Aerzen USA Corporation Alemite & Instrument Div. Alphasonics, Inc. Dresser Measurement Enterra Instrumentation Technologies Fischer & Porter Company Fluid Components, Inc. The Foxboro Company Groth Equipment Corp. Hedland Div. of Racine Federated, Inc. Kurz Instruments, Inc. Neotronics N.A., Inc. Pierburg Metering Systems, Inc. Process & Cyrogenic Services, Inc. Semblex Sensidine, Inc. Sierra Monitor Corp. Spectra Gases, Inc.