



CALIFORNIA
ENERGY
COMMISSION

Economic and Financial Aspects of Landfill Gas to Energy Project Development in California

CONSULTANT REPORT

APRIL 2002
500-02-020F



Gray Davis, Governor

CALIFORNIA ENERGY COMMISSION

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Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (the Commission, Energy Commission), annually awards up to \$62 million through the Year 2001 to conduct the most promising public interest energy research by partnering with Research, Development, and Demonstration (RD&D) organizations, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following six RD&D program areas:

- Residential and non-residential buildings end-use energy efficiency
- Industrial, agricultural, and water end-use energy efficiency
- Renewable energy technologies
- Environmentally preferred advanced generation
- Energy-related environmental research
- Strategic energy research.

In 1998, the Commission awarded approximately \$17 million to 39 separate “transition” RD&D projects covering the 5 PIER subject areas. These projects were selected to preserve the benefits of the most promising ongoing public interest RD&D efforts conducted by investor-owned utilities prior to the onset of electricity restructuring.

What follows is the final report on an investigation into the economic and financial aspects of landfill gas to energy project development in California.

For more information on the PIER Program, please visit the Commission’s Web site <http://www.energy.ca.gov/pier/reports.html> or contact the Commission at (916) 654-4628.

Executive Summary

Landfill gas (LFG) is produced by the anaerobic decomposition of buried organic waste. Municipal solid waste landfills produce significant quantities of LFG, and LFG will continue to be produced long after a landfill is closed. LFG typically has a methane content of about 40 to 55 percent. The balance is primarily carbon dioxide. If LFG is not beneficially used, it is incinerated in a flare. Flared LFG represents a wasted energy resource.

LFG can be, and has been, productively utilized as a substitute for natural gas at an end user's gas burning equipment, for electric power generation, and to produce high quality gas for direct injection into natural gas pipelines. A variety of technologies have been used for electric power generation, including reciprocating engines, combustion turbines, steam cycle power plants and microturbines.

The attached report provides an overview of the technologies available to productively utilize LFG and discusses not only technical and performance issues, but also capital and operating costs. It discusses project development issues, including permitting, financing, ownership, energy sales opportunities, and potentially available grants, tax credits and other financial incentives that are available for LFG utilization projects.

The beneficial use of LFG, known as landfill-gas-to-energy (LFGTE), is a well proven, environmentally beneficial and economically attractive means to satisfy some of California's energy requirements. As of July 2001, there were 38 LFG-fired electric power generation projects operating in California with an aggregated capacity of just over 200 MW. Potential projects could more than double this capacity.

1.0 Landfill Gas to Energy Overview

1.1 Landfill Gas Availability

Landfill gas (LFG) is produced by the anaerobic decomposition of organic waste in a landfill. Organic wastes include food waste, paper, wood, yard waste, and organic sludge. Municipal solid waste contains a relatively large organic waste fraction. Industrial wastes, and therefore industrial landfills, generally contain much smaller fractions of organic waste. LFG collection, control and utilization are, as a consequence, focused almost exclusively on municipal solid waste landfills.

LFG production begins shortly after waste is buried in a landfill and LFG will continue to be produced as long as organic waste is present. The decline in LFG production is gradual. In a dry climate, like Southern California, the rate of production will decline as little as 2 percent per year. In wetter climates, like Northern California, the rate of LFG production will decline at 6 percent per year.

Moisture is a significant factor in the rate of LFG production. The amount of moisture present in municipal solid waste does not vary appreciably in different regions in California, but additional moisture finds its way into the waste from precipitation. Landfills are designed to prevent the entry of water both during and after their active life; however, when the landfill is active, some water is inevitably added. The amount of water added is directly related to the precipitation in the region. LFG production can generally be correlated to the amount of annual precipitation in a region.

The most important factors affecting the amount of LFG produced from a fixed quantity of waste at any point in time are:

- the quantity of waste (in tons);
- its age (in years); and
- the annual precipitation at the landfill (in inches).

There are several models which are available to project the amount of LFG which is being produced or will be produced in the future at a landfill. The most widely used model at the present time is a first-order model (sometimes called the Scholl Canyon Model). USEPA's air emissions estimation model is a first-order model which is available at no cost. Copies of the model and operating instructions can be found at www.epa.gov/ttn/catc [Product Information, Software (executables & Manuals), Landfill Gas Emissions Model (Version 2.01)].

While moisture is an important variable governing variations in LFG production, other factors play a role, including waste temperature, pH and availability of nutrients. The waste management industry has recently focused research and development efforts on a landfilling concept known as a "bioreactor." The bioreactor incorporates a series of cells of waste in which the principal parameters affecting waste decomposition are controlled with the intent of maintaining optimum conditions for waste degradation. The waste management industry sees several potential benefits from bioreactors, including quicker production of additional air space to support more waste disposal per acre, and quicker stabilization of waste. The later benefit would reduce long-term, post-closure maintenance costs of a landfill. The addition of liquid and its recirculation are common features of most bioreactor projects. The increased rate of

waste degradation associated with bioreactors will increase the rate of LFG production. A bioreactor would allow a larger LFGTE project to be installed sooner; however, this benefit may be at the expense of LFG production in the future. In conventional landfills, it is assumed that the total amount of LFG which can be produced by a mass of waste is a fixed value. The fixed value is known as the ultimate generation rate, and is expressed as ft^3/ton or m^3/mg . It is not known whether or not a bioreactor will increase total LFG production on a ft^3/ton basis. If it does not increase the ultimate generation rate, then the benefit of a bioreactor, from the perspective of LFGTE, is only to produce the fixed amount of LFG faster.

1.2 LFGTE Alternatives

LFG beneficial use can be grouped into three categories as follows:

- Medium-Btu Gas Production (sometimes called “Direct Use”);
- Electric Power Generation; and
- Pipeline Quality Gas Production (sometimes called “High-Btu Gas” production).

Electric power can be generated through the application of:

- reciprocating engines;
- combustion turbines;
- steam cycle power plants;
- emerging technologies including microturbines, fuel cells and Stirling engines; and
- co-firing of LFG with fossil fuels in conventional electric power plants.

Medium-Btu gas utilization is a concept through which the LFG is given minimal cleanup and is used to completely or partially displace a fossil fuel in boilers (commercial, institutional and industrial), furnaces and kilns. Co-firing of LFG with fossil fuel in conventional power plants is typically considered to be a medium-Btu LFG application, even though electric power is being produced.

High-Btu gas production involves extensive cleanup of the LFG to a level of quality so that it can be introduced into existing pipelines as a direct substitute for natural gas. High-Btu gas can also be compressed or liquefied and be used for vehicle fuel. Technologies currently in use for production of high-Btu gas include the membrane process, the solvent absorption process, and the molecular sieve process.

Figure 1 identifies the range of beneficial uses and technologies to be discussed in this report.

1.2.1 Medium-Btu Gas Utilization

When LFG is used as a medium-Btu gas, it is directly used as a substitute for fossil fuel with very little treatment. The LFG is used at the methane content as seen at the landfill’s flare station -- which is about 40 to 55 percent methane. The LFG has an energy value of 400 to 550 Btu/ ft^3 (HHV). It can be blended with natural gas -- which has an energy value of 1,000 Btu/ ft^3 (HHV) or it can be fired separately. The principal advantage associated with medium-Btu gas utilization is that the carbon dioxide does not need to be removed prior to LFG utilization. This

results in a significant reduction in LFG processing costs. The cost savings is partially offset by the need to construct a dedicated pipeline direct to the gas user and/or the need to modify the user's piping and fuel burning equipment to accommodate LFG firing. The cost of a dedicated pipeline can be largely eliminated if the potential LFG user is located at or adjacent to the landfill.

Medium-Btu gas has been successfully used at more than 50 locations in the United States. The applications include:

- firing in commercial, institutional and industrial boilers at colleges, hospitals, and several types of industries;
- firing in industrial furnaces, including cement kilns, aggregate dryers, ovens and waste incinerators; and
- firing in conventional electric power plants with coal or natural gas.

The key to development of a successful medium-Btu gas project is identification of a fairly large, year round user of fossil fuel which is not too distant from the landfill.

Figure 2 shows the standard process for production of medium-Btu gas. Compression is employed in order to: (1) reduce the diameter of the conveyance pipeline; (2) to overcome pressure losses as the gas moves through the conveyance pipeline; and (3) to supply an end point pressure suitable for the user's needs. Refrigeration is employed for advanced moisture removal to assure that no condensate is formed in the conveyance pipeline and to produce a moisture-free gas for the end user.

If the end user's fuel specification is particularly demanding, then hydrogen sulfide and/or non-methane organic compound (NMOC) removal can be added to the treatment process; however, the addition of such steps is unusual. Figure Nos. 3 and 4 illustrate these add-on processing steps.

Compression, cooling, and chilling results in increased production of LFG condensate and the generation of liquid hydrocarbon waste. The liquid hydrocarbon waste will consist of oil carried over from the compressors and hydrocarbons condensed from the LFG. The liquid hydrocarbon waste is usually not hazardous, but must be sent to a proper disposal outlet.

1.2.2 Electric Power Generation

Reciprocating Engines

Reciprocating engines are the most widely used prime movers for LFG-fired electric power generation. Waukesha, Superior, Caterpillar, and Jenbacher are the most commonly employed equipment suppliers. The capacity of the individual engines proven in LFG service varies from 0.1 MW to 3.0 MW. Reciprocating engines are manufactured in capacities much larger than 3 MW; however, the larger units have not been proven in LFG service. It is believed that the largest LFG-fired reciprocating engine-based power plant is in the United States, and has a net

power output of 12 MW. There are more than 200 LFG-fired reciprocating engine power plants operating worldwide.

The principal advantage of reciprocating engines as compared to other power generation technologies is a better heat rate at lower capacities. An additional advantage of reciprocating engines is that the units are available in many different incremental capacities, which makes it easy to tailor the size of small plants to the specific rate of gas production at a landfill. Most small LFG power plants employ reciprocating engines.

An important disadvantage to reciprocating engines is that they produce higher emissions of NO_x, CO, and NMOCs than other electric power generation technologies. Significant progress has, however, been made in reducing NO_x emissions in recent years. A second disadvantage to reciprocating engines is that their operation/maintenance costs on a per MWh basis are higher than for other power generation technologies.

Station load for a reciprocating engine plant is about 7 percent of gross power output. The net heat rate for a typical reciprocating engine plant is 10,600 Btu/kWh (LHV).

Typical air emissions for a reciprocating engine plant are as follows:

	lbs/MMBtu
NO _x	0.200
CO	0.790
NMOCs	0.490
SO _x	0.008
Particulates	0.160

The jacket water coolers and lube oil coolers for reciprocating engines normally reject their heat through closed-loop, liquid-to-air heat exchangers. Wastewater is not produced in satisfying the plant's cooling requirements. Figure 5 is a schematic showing electric power generation with a reciprocating engine. In some cases, it may be possible to productively utilize the waste heat of a reciprocating engine plant.

Reciprocating engines generally require a relatively simple LFG pretreatment process consisting of compression and removal of free moisture. Free moisture (water droplets) is removed by use of simple moisture separators (knockout drums), cooling of the LFG in ambient air-to-LFG heat exchangers, and coalescing-type filters. Moisture removal also removes particulates; however, LFG is generally fairly particulate free. Some of the NMOCs in the LFG are removed as a result of compression and cooling. Compression is usually provided by flooded screw-type blowers or centrifugal blowers. The reciprocating engines can require between 3 psig and 60 psig of fuel

pressure. Figure 6 is a schematic showing the cleanup process for LFG for a reciprocating engine plant.

A few of the early LFG-fired reciprocating engine plants employed refrigeration units to chill the LFG to 40° F in order to induce additional moisture and NMOC condensation. It is also possible to use desiccant-type dryers instead of chillers and/or to employ activated carbon for advanced NMOC removal.

Engine manufacturers place restrictions on the amount of sulfur bearing compounds and the total organic halide content which they will tolerate in the LFG. Hydrogen sulfide is the principal sulfur-bearing compound in LFG. Chlorine is present in some of the NMOCs found in LFG. Chlorinated compounds are responsible for virtually all of the organic halides in LFG. LFG infrequently exceeds the limits for hydrogen sulfide and NMOCs imposed by reciprocating engine manufacturers; for this reason, a pretreatment scheme consisting of compression and simple moisture separation (knockout drum, air-to-LFG heat exchanger and coalescing filter) is virtually always the extent of LFG processing at a reciprocating engine plant.

Combustion Turbines

While less prevalent than reciprocating engines, combustion turbines have seen widespread use as prime movers in LFG-fired electric power generation. The most widely used combustion turbine is the 3.3 MW Solar Centaur. The Solar Saturn (1.0 MW) and Solar Taurus (5.2 MW) turbines have also been used in LFG service. Virtually every LFG-fired combustion turbine installation is a simple-cycle installation.

The principal advantages of the combustion turbine as compared to a reciprocating engine are its lower air emissions and lower operation/maintenance costs. The principal drawback to the combustion turbine is its high net heat rate. The poor net heat rate owes itself to two factors. First, the station power for a combustion turbine based plant is about 15 percent of gross power output as compared to about 7 percent for a reciprocating engine-based plant. The combustion turbines require a much higher gas pressure which increases the power consumption of the fuel gas compressors. Second, the combustion turbines used in LFG electric power production are small, and are not as efficient as the larger units commonly employed in the electric power industry. The largest LFG-fired combustion turbine plant is believed to be in the United States and consists of five Solar Centaurs with a gross capacity of 16.5 MW. Solar has more experience with LFG than any other combustion turbine manufacturer. There are more than 35 combustion turbines operating on LFG at more than 20 power plants.

Station load for a simple cycle combustion turbine plant is about 15 percent, and net heat rates vary from 12,200 Btu/kWh to 16,400 Btu/kWh (LHV). The larger, new combustion turbines are more fuel efficient.

Combustion turbines have traditionally achieved low NO_x emission rates based on water injection, steam injection, SCR or dry low-NO_x burner technology. None of these technologies have been applied to LFG due to technical/operational concerns, and due to the fact that NO_x

emissions when firing on LFG are lower than when firing on natural gas under otherwise identical conditions. Air emission rates for NO_x, CO, and NMOC, when firing on LFG in a Solar combustion turbine, are expected to be as follows:

	lbs/MMBtu
NO _x	0.120
CO	0.090
NMOCs	0.015
SO _x	0.008
Particulates	0.160

The combustion turbine/generator and the fuel gas compressors normally reject their heat through closed-loop, liquid-to-air heat exchangers. Wastewater is not produced during cooling.

Virtually all combustion turbine installations to date have been simple-cycle installations. Simple cycle plants have been preferred because the power plants have been relatively small and because LFG is an inexpensive fuel. Figure 7 contains schematics showing simple cycle and combined cycle combustion turbine configurations.

Combustion turbines require a higher pressure fuel supply than reciprocating engines. The required fuel supply pressure is in the range of 150 psig to 250 psig. Two stages of LFG compression are employed. Particulate in the LFG has sometimes caused problems with the combustion turbine's fuel injection nozzles. A small water wash scrubber is normally provided in the pretreatment process to prevent this problem. Figure 8 is a schematic showing the cleanup process for LFG for a combustion turbine-based power plant.

If required by a combustion turbine manufacturer, hydrogen sulfide and/or NMOCs can be removed. Solar has not required hydrogen sulfide nor NMOC removal in installations to date. Removal of these compounds may be required if a less experienced combustion turbine manufacturer is employed or if environmental regulations require installation of an SCR for NO_x or CO control. Activated carbon is normally employed to remove compounds which would otherwise cause SCR catalyst fouling. Hydrogen sulfide can be removed in a solid media absorber vessel (containing an iron sponge or a proprietary compound such as Sulfatreat) or in a liquid scrubber. Figures 3 and 4 are schematics showing hydrogen sulfide and VOC removal processes.

Steam Cycle Power Plants

Conventional boilers with steam turbines have seen limited application in LFG-fired electric power production. It is believed that eight steam cycle power plants are operating on LFG worldwide. Most LFG-fired power plants are less than 10 MW in capacity, which puts the steam cycle at a cost disadvantage when compared against reciprocating engines and combustion turbines. The steam cycle power plant becomes more cost competitive as the size of the plant increases.

The steam cycle power plant offers lower air emissions than either reciprocating engines or combustion turbines. As a consequence, steam cycles have been given preferential treatment in regions with stringent air quality regulations, even when the size of the plant was relatively small.

The smallest operating steam cycle power plant is a 6 MW plant at the BKK Landfill (West Covina, California, USA) and the largest is a 50 MW plant at the Puente Hills Landfill (Whittier, California, USA). The 50 MW power plant at the Puente Hills Landfill has been in operation for almost 15 years and has been extremely reliable, demonstrating a capacity factor of over 96 percent.

The heat rate of a steam cycle power plant is dependent on the details of the power cycle as established by the design engineer. The most efficient units operate at a gross heat rate of about 10,100 Btu/kWh (HHV). The least efficient units operate at gross heat rates as high as 15,200 Btu/kWh (HHV). Station load is in the neighborhood of 8 percent. Net heat rates are, therefore, in the range of 11,000 Btu/kWh to 16,500 Btu/kWh (HHV). The most efficient steam cycles use higher temperature and pressure (1,000°F/1,350 psig), air preheaters and up to five stages of feedwater heating. The least efficient units operate at low temperature and pressure (650°F/750 psig), and are not equipped with air preheaters or feedwater heaters.

NO_x emissions, when firing on LFG, are roughly half the NO_x emissions when firing on natural gas, with other conditions the same. Low levels of NO_x can be achieved through the application of recycle flue gas. Air emissions for a steam cycle power plant employing recycle flue gas are as follows:

	lbs/MMBtu
NO _x	0.03
CO	0.01
NMOCs	0.005
SO _x	0.008
Particulates	0.02

The wastewater generated by an LFG-fired steam cycle power plant is identical to that of a natural gas-fired steam cycle power plant. The wastewater includes boiler blowdown, wastewater from boiler make-up water treatment, and cooling tower blowdown. Figure 9 is a schematic showing the steam cycle power plant concept.

LFG requires no pretreatment prior to firing in a conventional boiler. LFG is normally taken from the discharge side of the LFG blowers in the landfill's flare station. Large water droplets and particulates have already been removed in the flare station's moisture separator. LFG pressure is increased to the pressure required by the boiler's burners by a set of LFG booster blowers to the pressure range of 1 psig to 4 psig.

Fuel Cells

The general public was first introduced to fuel cells in the 1960s when fuel cells began to provide internal power for manned spacecraft. Fuel cells chemically convert hydrogen and oxygen to electricity while emitting water vapor and carbon dioxide. Tanks of hydrogen and oxygen supply the feedstock for spacecraft applications. In terrestrial applications, the oxygen is supplied by the ambient air and hydrogen is produced from methane or other hydrogen containing feedstock. Fuel cells have interested the power generation industry and regulators due to their high fuel efficiency and ultra low emissions.

There are several types of fuel cells either available or under development including: phosphoric acid type, molten carbonate type, solid oxide type, and polymer-membrane type. The phosphoric acid type is commercially available. An International Fuel Cells Corporation (IFC) subsidiary, the ONSI Corporation, has shipped more than 200 of their PC25 package fuel cells since its introduction in 1991.

The 200 kW PC25 package includes three steps in a 10' wide by 20' long by 10' high box:

- A fuel processor in which natural gas is converted to a hydrogen rich gas using steam reformer technology;
- A power section in which hydrogen is combined with oxygen (from the air) to produce DC power, water, carbon dioxide and heat; and
- A power conditioner where DC power is converted to AC power.

If it is possible to put the heat to a productive use, then total efficiency of the fuel cell can be further enhanced.

The fuel cell is considered an opportunity for LFG utilization since it contains methane, the feedstock for stationary fuel cell applications. There have been two relatively short-term but successful fuel cell demonstration tests to date. There is one commercially operating unit. Fuel cells are nevertheless attractive to the LFG utilization industry because: (1) they are available in small incremental capacities (making them applicable to projects smaller than possible with other power generation technologies); (2) they produce almost zero emissions of criteria pollutants and produce little noise; (3) they can operate with little supervision; and (4) they are believed to have moderately low operating costs. The principal obstacle to widespread application for projects in the 200 kW to 2 MW range is high capital cost.

LFG cleanup is an important issue. Commercially available fuel cell packages employ catalysts which would be fouled by trace compounds in LFG.

A LFG cleanup system for a fuel cell would include:

- an adsorber for hydrogen sulfide removal;
- chilling and desiccation (to remove moisture and some hydrocarbons); and
- activated carbon to adsorb remaining trace organics.

Microturbines

The microturbine is a recently commercialized distributed generation technology. As of June 2001, two companies manufacture and sell microturbines -- Capstone Turbine Company (Chatsworth, CA) and Honeywell Power Systems (Albuquerque, NM). Capstone currently

offers a 30 kW and a 60 kW unit. Honeywell currently offers a 75 kW unit. Capstone has delivered more than 3,000 units. Honeywell has delivered more than 300 units. At least three other microturbine manufacturers will soon offer units for general sale -- Elliot Energy Systems (Secure Power); Ingersol Rand (NREC Energy Systems); and ABB/Volvo. It is expected that these manufacturers will release units in the 45 kW to 100kW range within the next one to two years.

Most microturbine installations to date have employed natural gas as their fuel. Permanent (versus experimental) microturbine installations have also burned oil field flare gas, municipal wastewater treatment plant digester gas and LFG. As of June 2001, there are about 50 microturbines operating on these waste fuels. An additional 100 units were being installed, and are expected to be operational as of September 2001. As of June 2001, the longest run time for a microturbine on natural gas was about 16,000 hours. The longest microturbine run time on waste fuel was about 8,000 hours. The longest run time on LFG was about 2,000 hours.

The microturbine is a derivative of the much larger combustion turbines employed in the electric power and aviation industries. Combustion air and fuel are mixed in a combustor section, and the release of heat causes the expansion of the gas. The hot gas is sent through a gas turbine which is connected to a generator. The units are normally equipped with a recuperator, which heats the combustion air using turbine exhaust gas in order to increase the unit's overall efficiency. The combustion air is compressed using a compressor which is driven by the gas turbine. The fuel must be supplied to the combustor at 70 psig to 80 psig. In some natural gas fired applications, the gas is available at this pressure from the pipeline. In LFG applications, a gas compressor is required. The microturbine differs from traditional combustion turbines in that the microturbine spins at a much faster speed. The microturbines which are now on the market are equipped with air bearings rather than traditional mechanical bearings in order to reduce wear.

A typical LFG fired microturbine installation would have the following components:

- LFG compressor(s);
- LFG pretreatment equipment;
- Microturbine(s);
- Motor control center;
- Switchgear; and
- Step-up transformer.

Microturbines require about 13,900 Btu/kWh (LHV) of fuel on a gross power output basis. Station load is about 15 percent, resulting in a net power output of about 16,350 Btu/kWh (LHV).

Microturbines are most applicable where the following circumstances exist:

- Low quantities of LFG are available;
- The LFG has a low methane content;
- Air emissions are of great concern;

- Emphasis is being placed on satisfaction of on-site power requirements, rather than exporting power; and/or
- A requirement for hot water exists at or near the landfill.

Microturbines can operate on LFG with a methane content of 35 percent (and perhaps as low as 30 percent). A 75 kW unit requires less than 50 scfm of LFG (at 35 percent methane content). Microturbines can be used at small landfills and at old landfills where LFG quality and quantity would not support more traditional LFG electric power generation technologies.

Air emissions from a microturbine are much lower than for a reciprocating engine. Microturbines have demonstrated NO_x emissions less than one-tenth those of the best performing reciprocating engines. The NO_x emissions from microturbines are lower than the NO_x emissions from a LFG flare. NO_x emissions of less than 0.01 lbs/MMBtu have been demonstrated by microturbines fired on LFG.

It is possible to produce hot water (up to 200°F) from the waste heat in the microturbine exhaust. Microturbine manufacturers offer a hot water generator as a standard option. Landfills in colder climates probably have a space-heating requirement -- which is often satisfied by a relatively expensive fuel (such as propane). Hot water users (such as hotels, industrial or institutional buildings, etc.) are sometimes adjacent to landfills -- particularly closed landfills. The sale or use of microturbine waste heat can significantly enhance project economics.

Microturbines have the following advantages as compared to reciprocating engines:

- Lower air emissions;
- Availability in smaller incremental capacities; and
- Ability to burn a lower methane content LFG.

Disadvantages of microturbines as compared to reciprocating engines include the following:

- A higher heat rate (about 35 percent more fuel consumed per kWh produced); and
- Limited experience on LFG.

The higher heat rate of the microturbine is generally not an issue since LFG is waste fuel.

1.2.3 Pipeline Quality Gas Production

LFG typically contains about 40 to 55 percent methane when it reaches the landfill's flare station, with the balance of the gas consisting primarily of carbon dioxide and secondarily of air (nitrogen plus oxygen) plus water vapor. LFG also contains trace compounds including NMOCs (such as toluene, trichloroethylene and vinyl chloride) and hydrogen sulfide. LFG has an HHV of about 400 to 550 Btu/ft³. LFG can be used to displace natural gas use in two ways. First, it can be subjected to light cleanup and be transmitted to an end user through a dedicated pipeline. The product gas retains its original energy content and the LFG displaces or is blended with natural gas at its point of use. Natural gas has a heating value of about 1,000 Btu/ft³ (HHV). As discussed above, this "direct use" of LFG is commonly known as "medium-Btu" gas use.

A second way to displace natural gas is to inject it into an existing natural gas distribution network. Natural gas, as distributed through pipelines to customers, must meet strict quality standards. Pipeline operators will allow LFG to enter their pipelines only after the LFG has been processed to increase its energy content and to meet strict standards for hydrogen sulfide, moisture, carbon dioxide and NMOCs. The need to roughly double the energy content of LFG has lead the LFG utilization industry to call gas beneficiated to pipeline quality “high-Btu” gas.

A typical pipeline quality gas specification is as follows:

- Heating value (HHV) > 970 Btu/ft³
- Hydrogen Sulfide < 4 ppmv
- Water Vapor < 7 lbs/million ft³
- Oxygen < 0.4 %
- Carbon Dioxide < 3 %
- Nitrogen plus Carbon Dioxide < 5 %

The 970 Btu/ft³ (HHV) limitation requires, in effect, that oxygen plus carbon dioxide plus nitrogen be limited to less than 3 percent. The product gas must also be free of environmentally unacceptable substances and must be pressurized to the pressure of the pipeline to which the gas production facility is interconnected. Pipeline pressure typically varies from 100 to 500 psig.

The following steps must be taken to convert LFG to pipeline quality gas:

- Prevention of air infiltration into the LFG well field;
- Moisture removal;
- Sulfur removal;
- NMOC removal; and
- Carbon dioxide removal.

The removal of carbon dioxide is the principal step taken to increase energy content. The prevention of air infiltration into the well field is also a critical step, not only because air infiltration reduces energy content, but also because it is necessary to satisfy tight product gas nitrogen and oxygen limitations. The addition of processing steps to remove nitrogen and oxygen from the LFG is widely viewed as being prohibitively expensive. At most landfills, elimination of air infiltration will require that the utilization facility be supplied by wells located in the “core” of the landfill. A separate perimeter LFG collection system must often be operated for gas migration control. Each well on the core gas system must be carefully monitored to maintain as close as practical “zero” air infiltration operation.

Carbon dioxide can be removed from LFG using three well-proven technologies: the membrane process, the molecular sieve, and solvent absorption.

Membrane Process

The membrane process exploits the fact that gases, under the same conditions, will pass through polymeric membranes at differing rates. A “fast” or highly permeable gas such as carbon dioxide will pass through a membrane approximately 20 times faster than a “slow” or less permeable gas such as methane. Pressure is the driving force for the separation process. The feed gas (LFG) and product gas (predominately methane) enter and exit the membrane module at approximately the same pressure. The permeate gas (predominately carbon dioxide) exits at a lower pressure. The operating pressures, number of membrane stages in series, and provisions for gas recycle depends on desired methane recovery percentage and product gas methane purity. In natural gas processing applications, both methane recovery percentage and desired product gas methane purity are highly important. In LFG applications, product gas methane purity is of paramount importance; however, methane recovery as a percentage of methane in the raw LFG is of less importance. The membrane configuration employed for a LFG utilization project should strike the optimal balance between capital cost and methane recovery on a given project. Total methane recovery is normally about 85 percent and the product gas contains 97 percent methane.

Figure 10 is a diagram of the membrane separation process. Two stages of membranes plus recycle of second stage permeate generally represents an optimal configuration for a pipeline quality gas project.

The membranes must be protected against moisture, NMOCs and particulates. These impurities can harm the membranes and reduce their life. Figure 11 shows the process which has been used to cleanup LFG prior to processing the LFG through the membrane process. It is necessary to compress the LFG to about 600 psig. This is accomplished through two stages of compression. Moisture is first removed through moisture separators and post-compression cooling of the LFG. The compressors can be driven by electric motors or by reciprocating engines fired on raw LFG, pretreated LFG, or product gas. Refrigeration is used to achieve advanced moisture removal. A separate hydrogen sulfide removal step is added only if the LFG hydrogen concentration exceeds 60 ppmv. If the hydrogen sulfide concentration is less than 60 ppmv, then the membrane alone can meet the 4 ppmv hydrogen sulfide product gas specification. The activated carbon step removes NMOCs not condensed by the time the LFG reaches the activated carbon vessels. The activated carbon is regenerated on site and the NMOC-laden waste stream is directed to a thermal oxidizer for destruction of the NMOCs. The reject carbon dioxide stream from the membranes is also directed to the same thermal oxidizer where auxiliary fuel (typically LFG) may or may not be required to support high-temperature combustion.

Molecular Sieve

The molecular sieve is a vessel which contains a media which preferentially adsorbs certain molecules (in this case carbon dioxide) when contacted with a gas stream which is under pressure. When the adsorption capacity of the media is exhausted, the vessel is brought off-line and is regenerated through a depressurization and purge cycle. The carbon dioxide exhaust stream from the on-line molecular sieve vessels is used for purge. The stream is backflowed through the off-line molecular sieve to carry the waste stream to a thermal oxidizer. In some

instances, the waste stream can be discharged to the atmosphere. The thermal oxidizer generally requires some supplemental energy, which can be provided by LFG or product gas.

The molecular sieve relies on adsorption. Adsorption is a phenomenon whereby molecules in a fluid phase spontaneously concentrate on a solid surface without undergoing any chemical change. Adsorption takes place because forces on the surface of the adsorption media attract and hold the molecules that are to be removed. In the LFG processing application, a media is employed which prefers carbon dioxide. The adsorbed carbon dioxide is released from the surface of the media when the media is depressurized. The molecular sieve process is also known as pressure swing adsorption.

Figure 12 is a schematic diagram showing the molecular sieve process.

The adsorption media employed in the molecular sieve process must be protected against contaminants in the LFG. The LFG pretreatment process for the molecular sieve is virtually identical to the pretreatment process employed for the membrane process. A separate hydrogen sulfide removal step is required, however, since the molecule sieve is optimized for carbon dioxide removal.

Absorption Processes

A typical absorption process plant employs a liquid solvent to scrub NMOCs and carbon dioxide from the LFG. A solvent called Selexol is most frequently used. A typical absorption process plant employs the following steps:

- LFG compression (using electric drive, LFG fired engine drive, or product gas fired engine drive);
- Moisture removal (using refrigeration);
- Hydrogen sulfide removal in a solid media bed (using an iron sponge or a proprietary media such as Sulfatreat) or by liquid scrubbing;
- NMOC removal in a primary Selexol absorber; and
- Carbon dioxide removal in a secondary Selexol absorber.

In the Selexol absorber tower, the LFG is placed in intimate contact with the Selexol liquid. Selexol is a physical solvent which preferentially absorbs gases into the liquid phase. NMOCs are generally hundreds to thousands of times more soluble than methane. Carbon dioxide is about 15 more times soluble than methane. Solubility is also enhanced with pressure. The above principles are exploited to remove VOCs and carbon dioxide from the LFG to yield a purified methane stream. The Selexol vessels operate at pressures in the range of 500 psi. The Selexol liquid is regenerated by lowering its pressure (flashing) and then running air through the depressurized Selexol to strip off the VOCs and carbon dioxide. The stripper air is normally sent to a thermal oxidizer where all or part of the thermal energy required to support combustion is supplied by the VOCs and methane in the stripper air.

1.3 Overview of LFGTE Technologies in California

1.3.1 Existing Projects

Table 1 lists LFGTE projects operating in California as of July 2001. There were 38 electric power generation projects totaling a little over 200 MW. There were six medium-Btu projects operating as of July 2001.

The electric power projects include five steam cycle power plants, five simple cycle combustion turbine plants, and 28 reciprocating engine plants. The largest power plant was a 50 MW steam cycle power plant at Puente Hills Landfill in Whittier.

The largest medium-Btu project is at the Scholl Canyon Landfill. The LFG is compressed, refrigerated, desulfurized, and is sent through an 8-mile pipeline to the City of Glendale's conventional steam cycle power plant, where it is co-fired with natural gas to produce about 10 MW.

1.3.2 Planned and Potential Projects

Table 2 lists planned and potential LFGTE projects in California. Planned and potential projects could double the amount of electric power now being produced by LFG in California.

1.4 Benefits of LFGTE

The benefits of LFG collection and control/utilization are as follows:

- A reduction in greenhouse gas emissions by eliminating the uncontrolled release of methane to the atmosphere;
- A reduction in the potential for explosions in structures at or near a landfill;
- A reduction in odor emissions;
- A reduction in emissions of hazardous organic air pollutants to the atmosphere; and
- The recovery of a low-cost, relatively high-quality fuel.

The use of recovered LFG as a fuel results in additional benefits, including:

- reduced consumption of fossil fuel, a finite resource, with a renewable resource;
- a further reduction in greenhouse gas emissions through deferral of consumption of fossil fuel; and
- a reduction in energy cost to the user and/or reduction in net operating costs to the landfill owner (depending on the size and type of the LFGTE project).

1.4.1 Public Health and Safety Issues

Not all LFG is immediately emitted to the atmosphere. A portion can travel underground and accumulate in basements and other enclosed areas where methane concentrations in excess of methane's lower explosive limit (5 percent) can accumulate. The risk of explosion is not limited to structures on the landfill, since LFG can migrate hundreds of feet under ground beyond a landfill boundary. Methane migration represents a risk to existing structures and an obstacle to new commercial and residential property development. The risk is a long-term risk since most landfills will continue to generate significant quantities of LFG for more than 30 years after

closure. A properly designed LFG collection and control system can mitigate this risk; in fact, dozens of golf courses, office parks, convention centers, and residential developments have been built on or immediately adjacent to closed landfills after implementation of proper LFG control. In some cases, these facilities have become users of LFG.

1.4.2 Environmental Issues

The principal component in LFG is methane. Methane is believed to have more than twenty times the impact as a greenhouse gas than carbon dioxide on a weight basis. Collection and destruction of this methane, typically in a flare, converts the methane into carbon dioxide, which greatly reduces the greenhouse impact of LFG. If the LFG is used as a fuel, it displaces combustion of another fuel and generates an additional offset. A landfill with 5.5 million tons of typical refuse in place will emit in the range of 300,000 tons per year of carbon dioxide into the atmosphere. Collection and utilization of LFG can make significant national and worldwide contributions to greenhouse gas control efforts.

LFG is odorous and can be a nuisance to neighbors. LFG contains low levels of volatile organic compounds and toxic organic compounds (including toluene, xylene, and benzene). While present in low levels, significant quantities of volatile organic compounds and toxic compounds can be emitted to the atmosphere, due to the large volumes of LFG which landfills produce.

A 5.5 million ton landfill can emit in the range of 83 tons per year of volatile organic compounds and 55 tons per year of toxic organic compounds. Volatile organic compounds are a precursor to ground level ozone formation. LFG emissions are a threat to local air quality, and hence to public health. The volatile organic, toxic, and odorous compounds present in LFG are, however, readily destructible (typically 98 percent+) through combustion in flares or in conventional power generation and fuel burning equipment.

1.4.3 Energy Value

The principal benefit of LFG collection, from the perspective of the LFGTE industry, is that its collection produces a low-cost, fairly clean fuel. If a LFG collection system is installed for the purpose of achieving the above-outlined environmental and property protection benefits, then the fuel is available at a flare station at no net cost. Even if the total cost of LFG collection is allocated against its energy value, the cost of production (capital and operations cost) is usually much lower than the cost of natural gas. Often, the landfill owner and the fuel user strike a cost sharing agreement covering the cost of well field installation and operation.

1.5 Pathways to Project Implementation

1.5.1 Self-Development Versus Second-Party Developers

The most significant contractual/financial decision to be made by a landfill owner in the development of a LFGTE project is the decision whether to self-develop the project or to turn the project over to an independent developer. An independent developer is sometimes called a “second” party developer. The landfill owner is the “first” party. The landfill owner must weigh two considerations when making this decision:

- The landfill owner’s willingness to accept project risk; and

- The landfill owner's willingness to commit time and attention away from his principal business.

The landfill owner's willingness to accept project risk is the most important consideration in the decision making process. If the landfill owner elects to self-develop a project, then he must provide the capital. The capital is 100 percent at risk. He receives 100 percent of the project benefits, but is also exposed to 100 percent of the project losses. A second party will provide the capital for the project and insulate the landfill owner from project risk. The second party will compensate the landfill owner for the right to develop a project at his landfill; however, this compensation will be limited to only a fraction of the economic benefit produced by the project.

If the landfill owner decides to self-develop a project, the landfill owner can minimize the demand on his and his staff's time by hiring consultants to handle almost all of the details of project development and implementation; however, heavy reliance on consultants will result in additional funds being placed at risk in the earlier stages of project development. The heavy use of consultants reduces the concern with respect to the issue of time/attention diversion, but trades this benefit off against an increase in financial risk.

1.5.2 Project Risks

The two sections which follow discuss project risk and how project risks can be shared or minimized. A full understanding of project risk is necessary to make an informed decision on the preferred method of project development. Methods for mitigating and distributing project risk are also discussed. The risks will be discussed in the context of an electric power project since almost all of the LFGTE projects in California are or will be electric power projects.

A LFGTE electric power project, like any independent power project, must face and successfully overcome several uncertainties. The principal uncertainties faced by an independent power project include:

- total project construction cost;
- security of fuel supply and price;
- non-fuel annual operating cost;
- environmental and other permitting;
- plant performance;
- ability to secure financing; and
- ability to complete on schedule.

Total project construction cost includes:

- the initial costs incurred in project development (feasibility studies, permitting, legal/administrative costs of securing power sales and other agreements);
- financing costs (loan initiation costs and interest during construction);
- construction costs through final change orders; and
- initial funding of operating costs (during shakedown and start-up until electric power and its revenues are reliably generated).

The project risk associated with the uncertainty of project construction cost is, of course, that project construction cost may be underestimated, resulting in a decrease in the net income generated by the project. Project construction costs can increase due to a poor initial cost estimate or due to unforeseeables. Unforeseeables can include:

- permitting difficulties resulting in schedule delays and their associated cost escalation;
- cost increases due to hardware additions to cover more stringent environmental controls, including advanced air emission controls and noise controls; and
- increased consultant costs for permitting.

As the project develops beyond its initial stages and as more money and effort are expended, total project cost becomes better confirmed. A project can be terminated at any point; however, monies spent to the point of termination are lost. The major milestones in confirmation of total project construction cost are receipt of relevant permits, with identification of their attendant construction cost impacts, and execution of a firm construction cost contract.

Security of fuel supply and price is an important consideration in an independent power project since the projects are often financed over a 10- to 20-year period. While a commitment to supply coal or natural gas over a long term can fairly easily be secured, the unit price for these commodities is often difficult to fix or cap in future years. LFG has an advantage over fossil fuels in that 1) if a project is self-developed, the developer already owns the fuel; and 2) if there is a second party developer, then the LFG price can be agreed upon with certainty for the entire term of its anticipated use. The price need not be established on a strict \$/MMBtu basis, but could be set as a percentage of the gross power revenue generated by the project or on another mutually agreeable basis. While the certainty of price is better for LFG than for fossil fuel, its position with respect to certainty of supply is not as favorable. LFG availability is based on projections which incorporate assumptions on the waste's gas generation potential and on the stability of long-term landfill operations. Questions and concerns include:

- Will the landfill stay open for its permitted life and continue to receive wastes at the projected quantities? Regulatory changes, public pressures and changing market conditions can affect landfill life and waste receipt. Re-permitting or permitting of site extensions might be particularly troublesome.
- Will the landfill owner vigilantly operate the gas collection system to maintain a high quality and quantity of gas flow? In most cases, gas collection systems were installed to reduce air emissions, control odors or mitigate safety problems, and not to produce fuel gas. Further, day-to-day landfill operations can result in intermittent disruptions in gas supply.
- How accurate is the projection of gas production? While LFG recovery models have improved in recent years, they must often rely on imperfect input information. If a complete LFG collection system has been installed on at least a large segment of the existing landfill, it is possible to site calibrate the model, reducing much of the uncertainty in the LFG recovery projection.

One drawback to LFG is that it is available only where it is produced. The power plant must be sited at or fairly close to the landfill. Landfills are often located in regions where air emissions

permits are difficult to obtain. Finally, the project must be sized based on what LFG is available, not on what size makes the most economic/technical size.

The uncertainty of non-fuel annual operating on independent power projects is not great. This is also true for LFGTE projects. Initial year labor, routine maintenance and commodity consumption can be projected with a fair amount of certainty and the escalation of these costs can be established using reasonable judgment. The largest uncertainty is probably the extent of “non-routine” repair/replacement costs. Major equipment failures as a result of operator error or equipment defects beyond the warranty period are examples of non-routine repair/replacement costs. The hundreds of operating LFGTE power projects in the United States and the dozens of projects in California provide a database for operating cost information.

Environmental and other permitting is an area of uncertainty which is faced by virtually every commercial or public venture undertaken which involves construction. The principal concerns with permitting are cost impact and schedule impact. The schedule question, simply stated, is: How long will it take to secure the necessary permits and, in fact, can the more sensitive permits be secured with any reasonable expenditure of time and money? The conditions contained in the ultimately issued permits which govern air emissions, noise control, condensate disposal and ongoing environmental monitoring can greatly affect project construction and operating cost. As compared to other independent power projects, LFGTE projects are generally at an advantage with respect to permitting since they often result in a net reduction in air emissions and are sited in an area somewhat buffered from the public. In some instances, a LFGTE power project can be permitted as a routine matter.

The principal measures of plant performance are:

- heat rate (fuel consumption/kWh produced);
- plant output (kW);
- air emissions; and
- availability (ratio of the time the plant is able to operate to the total hours in a year).

Uncertainties associated with heat rate and plant output are not great when using proven technologies and experienced designers/equipment manufacturers. The same statement can generally be made with respect to air emissions; however, as technology is pushed to achieve lower levels of emissions, then the ability to comfortably achieve mandated air emissions becomes a concern. Most of the risks associated with heat rate, plant output and air emissions can be passed on to the equipment manufacturer and/or construction contractor; however, performance guarantees from equipment manufacturers and contractors normally involve commitments to simply rectify the deficiency and not to reimburse the owner for periods of reduced power output while the remedy is being implemented. Equipment manufacturers and contractors cannot bear the cost of consequential damages within their normal profit margins.

The issue of availability is one measure of performance that cannot be guaranteed over the long run by an equipment manufacturer or contractor -- unless he operates and/or maintains the plant at some premium cost. If the project owner desires comfort in this area from the equipment manufacturer and/or contractor, he must normally rely on short-term availability tests. Such tests are typically in the form of 7- to 30-day reliability tests at contract closeout. In

the case of LFGTE power projects, the equipment which is used has a long and successful track record in LFG service. Developers normally assume that their project will operate at availability levels equal to similar LFGTE projects.

The risk of financing is whether funds can be raised and whether they can be secured at reasonable terms. In a privately financed project, this uncertainty is overcome by demonstrating that the project will, with little doubt, produce a reasonable rate of return on investment and will, as a minimum, generate sufficient revenues to cover operating costs and debt service given the development of reasonably likely adverse conditions. Adverse conditions might be lower than forecast availability (a slightly greater prospect on a LFG project than a natural gas fired project) or fuel costs escalating more rapidly than assumed in the life cycle economic model (much less likely than for a natural gas fired project). The life cycle cost model is normally called a pro forma in the independent power industry. In a publicly financed project, the test is sometimes less stringent and the criterion is sometimes that the project simply does better than "break even." In a private non-recourse financing project, the risk of financing is not eliminated until all other risks have been minimized, and this usually occurs only after a construction contract is in place. The availability of financing and its terms on a public project can be confirmed much earlier if so desired. A private firm with a strong balance sheet and several successful, operating projects is generally in the position that it knows that it can secure financing. Project financing is discussed in greater detail in later sections of this report.

The final uncertainty is project completion schedule -- more specifically, how long will it take before the project is on the grid producing power? The above discussion identifies two major schedule concerns -- how long will it take to secure permits, and will there be problems in start-up? Delays in initiation of construction and in commercial operation result in cost escalation and postponement of anticipated revenue streams which will not only reduce the profitability of a project, but could also subject the project owner to cash flow problems. Some power sale agreements or incentive packages have "sunset" dates at which point the agreement is subject to cancellation or renegotiation and/or call for meeting of certain "milestones." Failure to meet the milestones can result in cancellation of the agreement or incentive.

There are two general rules with respect to risk on independent power projects which are even more applicable to LFGTE power projects:

Rule 1: Risk varies in indirect proportion to money and time expended.

Rule 2: When multiple parties are involved in execution of a project, the net profit which it generates must be shared in general portion to the risk allocated to and contribution made by each party.

As shown on Figure 13, uncertainty is reduced in a stepwise manner as specific milestones are met. The cumulative amount of money committed to the project also increases with each milestone. If an individual milestone causes the project to be considered infeasible, then the monies spent to that point are lost. If this occurs early, say at the completion of the feasibility study, then only the cost of the study is lost. If this occurs at the point of financing, then the cost of all work to that point is lost.

In general, the risks associated with a LFGTE power project are no greater than, and in some areas are less than, those associated with a conventional power plant.

1.5.3 Risk Allocation

A LFGTE power project can have a number of participants, including:

- the landfill owner;
- the owner of the gas collection facilities (if other than the landfill owner);
- the operator of the gas collection facilities (if other than the landfill owner);
- the owner of the power plant;
- the operator of the power plant;
- the construction contractor;
- the manufacturers of the major equipment;
- the architect/engineer;
- the equity holder(s); and
- the holder(s) of long-term debt.

In many project structures, one firm or entity fulfills several of these roles. Risk can be spread among these parties, depending on their interest in the project. The holder(s) of the long-term debt are perhaps the most risk adverse. They will seek to mitigate their risk by looking to the project developer to guarantee loan repayment through revenue sources other than the project itself and through the commitment of collateral other than the project itself. If the borrowing is on a “non-recourse” basis, the lenders will expect all other project participants to absorb virtually all risk. The holder(s) of long-term debt look at the project as an opportunity to lend funds at an interest premium, but want virtually 100 percent assurance that their investment will be repaid. The equity holder(s) are more entrepreneurial and bear the bulk of the financing risk. For accepting this risk, they will expect to be rewarded fairly handsomely -- typically an internal rate of return in the range of 20 to 25 percent. The bulk of the equity is normally held by the developer and his usual investment partners or, when the landfill owner acts as the owner-developer, the landfill owner himself. The equity holders, like the long-term lender(s), will attempt to pass risk along to other project participants. Project financing is discussed in greater detail in later sections of this report.

Typical strategies for risk transfer to various parties include transfer of risk to the following:

- **Equipment Manufacturers** – by seeking assurances on equipment performance and delivery time in the form of monetary penalties and other guarantees.
- **Construction Contractor** – by seeking an overall wrap-around guarantee on a total project basis in the areas of performance and schedule. A wrap-around is more easily obtained from a turnkey contractor rather than a general contractor.
- **Architect/Engineer** – by seeking guarantees on those aspects of schedule and performance under his direct control. Architect/engineers have traditionally limited their warranty to the redesign of deficient work; however, they have been increasingly accepting some risk, particularly when subcontracting to turnkey contractors.

- **Landfill Operator (or Gas Producer)** – by seeking discounts off of the fuel payments based on problems with gas delivery and gas quality.
- **Power Plant Operator** – by seeking bonus/penalty arrangements from the operations contractor keyed to plant availability (power output) and cost control.

1.5.4 Alternative Overall Implementation Structures

Figure 14 identifies several alternative structures for implementing LFG power projects. The alternatives vary to some degree depending on whether the landfill owner is a public or private entity or whether a decision is made to self-develop or to employ an independent developer in implementing the power generation project. The implementation options vary in their structure primarily in who installs/owns/operates the gas collection facilities and who installs/owns/operates the power plant. The project would normally involve only one or two parties -- two parties when a developer is employed and one party when the landfill owner self-develops. The qualification for tax credits usually results in a second or third party being brought into the project structure. The existing Federal alternative energy production tax credit is only available if the gas which is produced is sold to an “unrelated party” and is only of benefit if the producer has an “appetite” for tax credits. The second or third party must not necessarily be totally unrelated to the other parties, and structures have been developed which involve the principals in ways acceptable to the Internal Revenue Service. Figure 14 does not show every possible implementation structure, but it does show the most likely arrangements. In all options involving a second party, the landfill owner (either public or private) receives compensation in some form. The compensation can take the form of:

- a percentage of gross power revenue;
- a percentage of net revenue;
- gas purchase on a \$/MMBtu basis; or
- the avoidance (or reduction) in the cost of well field construction and operation/maintenance cost (if the landfill owner needed to install the well field for environmental or regulatory purposes).

1.6 Pertinent Regulations

California Code of Regulations (CCR) Title 27 requires that methane concentrations in the soil at the property boundaries of landfills not exceed 5 percent. The purpose of this regulation is to prevent the off-site migration of LFG in explosive concentrations. LFG collection and control systems in California are often installed to satisfy CCR Title 27. Responsibility for administering CCR Title 27 is delegated by state government to county or city government. The agencies responsible for enforcing CCR Title 27 are commonly known as local enforcement agencies (LEAs).

USEPA’s New Source Performance Standards (NSPS) for municipal solid waste landfills require that LFG collection and control systems be installed at all landfills which have a design capacity over 2.5 million Mg (2.75 million tons) and are projected to emit more than 50 Mg (55 tons) of NMOCs to the atmosphere per year. In California, a landfill with as little as 1 million tons of waste in place could be required to install a LFG collection and control system; however, a landfill with as much as 5 million tons of waste in place may not be required to install a LFG

collection and control system. The authority for administering NSPS has been delegated to the individual air quality management districts (AQMDs) and air pollution control districts (APCDs) throughout the state. NSPS was promulgated in 1996. Many of California's AQMDs and APCDs already had pre-existing LFG collection and control rules. Some of these rules were and continue to be more stringent than NSPS. In some cases, these rules require that landfills having less than 1 million tons of waste in place install LFG collection and control systems.

The benefit of CCR Title 27, NSPS, and related rules, from the perspective of the LFGTE industry, is that these rules require that LFG collection and control systems be installed solely to satisfy a regulatory purpose. The LFG is available at no cost. There are very few landfills in California which could support a LFGTE project greater than 0.5 MW in size which are not required by environmental regulations to install a LFG collection and control system.

NSPS requires that once LFG is collected, it must be processed through a device capable of achieving a 98 percent destruction of NMOCs (or an exhaust concentration of 20 ppmv). An enclosed flare is normally employed for LFG destruction. When LFG is used beneficially, the LFGTE facility replaces the flare for the portion of LFG which is beneficially used. LFGTE facilities, at NSPS sites, must also achieve a 98 percent destruction of NMOCs. If for a particular technology or landfill 98 percent destruction exceeds what would be Best Available Control Technology (BACT) from the perspective of the power plant alone, then the 98 percent destruction would still govern. If LFG is "treated," as it is in a pipeline quality project, then the LFGTE project is exempt from the NSPS requirement. It is unclear at this point whether a medium-Btu project would need to satisfy this requirement. A medium-Btu project only subjects the LFG to light clean-up, and USEPA has not issued clear guidance as to whether or not a medium-Btu project would satisfy their definition of treatment. At the present time, this issue needs to be addressed on a case-by-case basis during permitting.

A LFGTE project, like any project which generates air emissions, must obtain an air permit from an AQMD or APCD having jurisdiction over the landfill. The permitting processes typically involve determination of BACT, addressing offset issues, and health risk assessments. The air permitting process for a LFGTE project is generally no more difficult than for a project employing conventional fuel. Most AQMDs and APCDs are very supportive of LFGTE projects.

1.7 Impediments to LFGTE Development

1.7.1 Environmental/Permitting

Environmental and permitting issues seldom represent impediments to LFGTE development. LFGTE projects are normally located at a landfill, and the installation of a relatively small energy recovery facility at a site already committed to waste disposal is not viewed as a contradictory landfill use. The environmental impacts are minor. Air emissions are partially offset by reduced flaring of LFG. In a few instances, establishment of BACT and securing arrangements for offsets has delayed LFGTE project implementation; however, this is a very AQMD/APCD specific problem. For the most part, the determination of BACT has been straightforward and offsets have not been an issue.

1.7.2 Interconnection

LFGTE power projects are by definition qualifying facilities (QFs) because they are fired on waste fuel. As a QF, a power project is guaranteed the right to interconnect to the utility's grid at reasonable costs. Most LFGTE power plants are relatively small and the impact on the utility's grid is not significant. In some cases, however, the utility must increase the capacity of their transmission lines between the location of the LFGTE project and the location on their grid that can accommodate the amount of power produced by a LFGTE power plant. Under such circumstances, the interconnection can become a significant part of the plant's total construction cost. Impact on project schedule can also be a concern. The larger the impact on the utility, the longer the lead time needed by the utility to schedule and complete the interconnection work.

Interconnection problems can be avoided by contacting the local utility in the early stages of project development. Early identification of interconnection requirements will mitigate schedule delays and will allow the costs of interconnection to be fully reflected in the financing of the project.

California investor-owned utilities (IOUs) have their interconnection requirements specified in their Rule 21, which is filed with the California Public Utility Commission (CPUC). Implementation of Rule 21 requirements is fairly uniform for the California IOUs. An interconnection application, satisfying the requirements of Rule 21, must be filed with the local utility to begin the interconnection evaluation process. Municipal utilities have their own requirements governing interconnection, and the requirements of each utility must be individually addressed.

1.7.3 Economics and Financing

Individual LFGTE projects require only small to moderately large capital investments. Due diligence, legal and administrative activities and costs, which are associated with securing private debt and equity, are largely unrelated to the amount of money involved. It is sometimes difficult to attract private investment when a capital investment is relatively small. In addition, there is a very limited number of lenders and investors who have LFGTE experience.

The issue of investment size can often be overcome by aggregating individual projects into a portfolio containing several projects.

2.0 LFGTE Economics

2.1 Capital and Operating Costs of LFG Collection and Control in California

2.1.1 Conventional Landfills

The principal components of a LFG collection system are its extraction wells, the LFG collection piping (which allows the LFG to be drawn to a central location), and a blower/flare station (which contains vacuum blowers to pull the LFG to the blower/flare station and a flare to burn the LFG).

The extraction wells can consist of horizontal wells (known as trench collectors or horizontal collectors) or vertical wells. Horizontal wells can only be installed as waste is being placed. Vertical wells can be installed as waste is being placed or after a section of a landfill (or an entire landfill) is closed. The LFG collection piping can be buried, laid on the surface or placed on pipe supports. The installed cost of a LFG collection system varies based on the type of system installed. The cost is also affected by the depth of the waste in the landfill. The above variables make it difficult to quote general construction costs. A typical well field construction cost is \$15,000 per acre (with a range of \$10,000 to \$20,000 per acre). A typical well field operation/maintenance cost is \$650 per acre (with a range of \$400 to \$900 per acre) per year.

The construction cost of a blower/flare station is a function of LFG flow rate. LFG flow rate is primarily a function of the amount of waste in place. The amount of precipitation at the landfill and the average age of the waste are important factors affecting LFG flow rate. As a result, costs are best estimated on a per scfm basis. Blower/flare station construction costs range from \$350 to \$450 per scfm. Operation/maintenance costs range from \$20 to \$30 per scfm per year.

The total cost of LFG recovery (on an energy basis), assuming retirement of capital cost over 10 years at an interest rate of 10 percent, is about \$0.90/MMBtu (with a range of \$0.60 to \$1.20/MMBtu).

As discussed in Section 1, most landfills in California having significant LFG production potential are required by regulation to install LFG collection systems. As a result, there is no cost assignable to the energy recovered. LFG is sold to second parties or is used in self-developed projects to defray part of the cost of construction and operation/maintenance of the LFG collection facilities. When sold to second parties, the cost of LFG is a value set by market conditions, principally based on the value of the end product sold (e.g., electric power or medium-Btu gas), rather than on the actual cost of LFG production.

2.1.2 Bioreactor Landfills

At the present time, bioreactor landfills are in the early stages of full-scale field testing. The construction and operation/maintenance costs associated with bioreactor landfills are not known. Construction and operation/maintenance costs will be much higher for bioreactors (versus conventional landfills) on a per acre basis; however, the waste management industry expects lower long-term life cycle costs on a \$/ton basis. Even if costs were well defined, there is no clear method to allocate costs between LFG recovery and other bioreactor components. It is likely that LFG recovery costs on a \$/MMBtu basis will be lower for a bioreactor landfill than

for a conventional landfill. The cost reduction could be in the 25 percent to 50 percent range, depending on how bioreactor costs are allocated.

2.2 Costs of Medium-Btu Projects

Direct use (medium-Btu) projects have three components -- the compressor plant; the pipeline to deliver the LFG to the end user; and end user modifications to support LFG firing or LFG co-firing. The cost of the compressor plant is a function of its design flow rate and design pressure. The design pressure required from one project to another does not greatly vary and is typically in the range of 50 psig to 100 psig. Construction costs and operation/maintenance costs are primarily a function of flow rate. Flow rate is typically quoted in million standard cubic feet per day (mmscfd). The total installed cost of a medium-Btu compressor plant is in the range of \$600,000 to \$700,000/mmscfd. Operation/maintenance costs are about \$400 to \$500/mmscf (assuming electric motor drives at current California power costs). LFG can be processed at a cost of about \$600 to \$800/mmscf (or \$1.20 to \$1.60/MMBtu), assuming retirement of capital cost at an interest rate of 10 percent over 15 years.

The cost of the pipeline to an end user is a function of its length and its diameter. The diameter is a function of the design flow rate. Pipeline length (versus diameter) accounts for more than 80 percent of the pipeline cost. Pipeline cost is in the range of \$30 to \$40 per foot. Pipeline operation/maintenance costs are insignificant. Each 5,000 feet of pipeline adds about \$0.15/MMBtu to the LFG delivery cost.

The cost of end user modifications is highly variable, but these costs are usually borne by the end user and paid for through the cost savings he experiences from the use of LFG. The cost of LFG to the end user is generally indexed to his avoided conventional fuel cost. The discount which must be offered against the end user's avoided cost is partially a function of his expected conversion cost.

2.3 Capital and Operating Costs of Power Generation Facilities in California

2.3.1 Reciprocating Engines

The total installed cost of a LFG fired reciprocating engine power plant is in the range of \$1,100 to \$1,300/kW. The scope of the installation would begin with a LFG booster blower and end with a step-up transformer. The variability in price relates to differences in plant size, site conditions, and whether or not the equipment is installed in a building or is supplied in its factory-shipped containers. Larger plants and containerized installations would fall in the lower end of the price range. The price range quoted assumes a minimum plant size of 800 kW. The cost per kW does not significantly decrease when the plant size increases above 6 MW.

The operation/maintenance cost of a LFG fired reciprocating engine power plant, exclusive of LFG recovery cost, is in the range of 1.6¢ to 2.0¢ per kWh. The lower cost is associated with larger plants (3 to 6 MW) and the higher cost is associated with smaller plants.

The total cost of power production, based on net power output and assuming retirement of the capital cost over 15 years at an interest rate of 10 percent, would be in the range of 3.5¢ to 5.3¢ per kWh.

2.3.2 Combustion Turbines

The total installed cost of a LFG fired combustion turbine power plant is in the range of \$1,000 to \$1,200/kW. The scope of the installation would begin with a LFG compressor and end with a step-up transformer. The price range quoted above assumes a minimum plant size of 3.5 MW. Smaller LFG-fired combustion turbine plants are generally no longer being built and, if one were built, the cost would exceed \$1,200/kW.

The operation/maintenance cost of a LFG fired combustion turbine power plant, exclusive of LFG recovery cost, is in the range of 1.4¢ to 1.8¢ per kWh. The highest cost is associated with the smallest plants (3.5 MW), and the lowest cost is associated with larger plants (10 MW+).

The total cost of power production, based on net power output and assuming retirement of the capital cost over 15 years at an interest rate of 10 percent, would be in the range of 3.4¢ to 4.2¢ per kWh.

The cost of power production with a combustion turbine plant is comparable to the cost of a reciprocating engine plant, when similar in size, despite the combustion turbine's lower capital and operation/maintenance costs, because the ratio of net power output to gross power output is much lower for a combustion turbine power plant than for a reciprocating engine power plant. This causes net cost on a ¢ per kWh basis to increase.

2.3.3 Steam Cycle Power Plants

The total installed cost of a steam cycle power plant (on a \$/kW basis) varies greatly with plant size. It is generally acknowledged that steam cycle power plants are not cost competitive with other LFG power generation technologies at capacities under 20 MW. Plants smaller than 20 MW in size have been built; however, selection of a steam cycle in such instances has generally been due to air emissions issues, the availability of used equipment, or an owner preference for lower long-term operation/maintenance costs at the expense of higher initial capital costs.

The total installed cost of a LFG fired steam cycle power plant is in the range of \$2,500/kW (at 10 MW) to \$1,500/kW (at 30 MW+). The scope of the installation would begin with a LFG booster blower and end with a step-up transformer.

The operation/maintenance cost of a LFG fired steam cycle power plant, exclusive of LFG recovery cost, is in the range of 1.0¢ to 1.4¢ per kWh.

The total cost of power production, based on net power output and assuming retirement of the capital cost over 15 years at an interest rate of 10 percent, would be in the range of 3.6¢ to 5.5¢ per kWh.

2.3.4 Microturbines

The total installed cost of a LFG fired microturbine power plant can range from \$1,800 to \$3,000/kW. For a 30 kW installation, the cost is in the range of \$2,500 to \$3,000/kW. The cost of a 300 kW installation is in the range of \$1,800 to \$2,100/kW. Above 300 kW, there is little reduction in cost on a \$/kW basis. Further cost reductions are not possible since the maximum currently available microturbine size is 75 kW. When and if larger microturbines become

available, then the cost of a microturbine installation over 300 kW will decrease on a \$/kW basis.

The operation/maintenance cost of a LFG fired microturbine power plant, exclusive of LFG recovery cost, is in the range of 1.8¢ to 2.2¢ per kWh.

The total cost of power production, based on net power output and assuming retirement of the capital cost over 10 years at an interest rate of 10 percent, would be in the range of 6.5¢ to 9.3¢ per kWh.

2.3.5 Fuel Cells

The total installed cost of a fuel cell using LFG as feedstock would be in the range of \$3,800 to \$4,000/kW. The fuel cell which is currently commercially available for LFG service costs \$600,000 or \$3,000/kW. The operation/maintenance cost for a LFG fuel cell facility would be in the range of 2.0¢ to 2.5¢ per kWh.

The total cost of power production, based on net power output and assuming retirement of capital cost over 15 years at an interest rate of 10 percent, is in the range of 9.0¢ to 10.0¢ per kWh. Fuel cells employing waste material as feedstock often qualify for significant capital cost subsidies; however, even with a capital cost subsidy of 50 percent, fuel cells are currently not cost competitive with other LFG power generation technologies.

2.4 Costs of Pipeline Quality Gas Production Projects

Pipeline quality gas projects are generally in the 5 to 10 mmscfd (inlet flow) size range. A typical installed cost is \$1.2 million to \$1.5 million per mmscfd (inlet). Typical operation/maintenance costs are \$0.50 to \$1.00/mcf (outlet). Pipeline quality gas can be produced at a cost of \$1.70 to \$2.20/mcf (of natural gas equivalent), assuming retirement of capital cost over 15 years at a 10 percent rate of interest.

2.5 Total Cost of LFGTE Systems

The total construction costs, operation/maintenance costs and net production costs of a LFGTE system can be roughly estimated by use of the above outlined cost estimating guidelines. The costs of LFG collection can be included or excluded in these estimates, depending on the view taken toward these costs. The net production cost of electric power production using LFG varies greatly depending on project size and technology. The cost can range from as low as 3.4¢ per kWh to as high as 10¢ per kWh.

Medium-Btu gas can be delivered to an end user for a cost in the range of \$1.70 to \$2.10/MMBtu, assuming that a three-mile pipeline is required.

Pipeline quality gas can be produced for \$1.70 to \$2.20/mcf.

The above costs do not consider the beneficial impact of tax credits or other incentives. Section 3 discusses tax credits and incentives which are available to aid LFG recovery projects.

3.0 Financing of LFGTE Projects in California

3.1 Incentives and Credits Available to Support LFGTE Development

3.1.1 Federal

Section 29 Tax Credit

Section 29 of the Internal Revenue Code provides a tax credit to support the use of fuel from specific non-conventional sources. LFG, considered to be a biomass fuel, qualifies for this tax credit. The Section 29 tax credit is, and continues to be, the major incentive assisting the LFG utilization industry. The Section 29 tax credit is currently valued at about \$1.10 per MMBtu.

Under current Internal Revenue Service regulations, Section 29 tax credits can be claimed through 2007 for LFG collection facilities placed in service after December 31, 1992, and prior to June 30, 1998. Facilities installed after December 31, 1996 and prior to June 30, 1998 had to be constructed under a binding contract executed prior to December 31, 1996. LFG collection facilities placed in service prior to December 31, 1992 can claim Section 29 tax credits only through 2002.

It is important to note that it is not necessary that the LFG beneficial use have commenced operation before June 30, 1998. It is only necessary that the well field be placed in service by that date. The beneficial use can come on-line at any time through the diversion of LFG from a flare to a beneficial use. From the point of diversion forward, tax credits can be taken. A “grandfathered” well field is all that is necessary to claim tax credits.

The Section 29 tax credit is taken by the fuel producer. The fuel producer is the owner/operator of the well field. The LFG must be sold to an “unrelated party” for beneficial use. These conditions, coupled with the fact that all qualifying well fields are pre-existing, requires that innovative contractual arrangements be employed to implement tax credit transactions. It is very common for well field owners, typically landfill owners, to sell or lease their LFG collection system to parties better situated to make use of the tax credits. After well field ownership has transferred, the “unrelated party” test can still be met by the project developer by implementing the project through two independent companies -- a gas producing company (Gasco) and a power generating company (Genco).

The Internal Revenue Service (IRS) periodically issues Private Letter Rulings (PLRs) which change and clarify the definition of “facilities” and the definition of “replacement” wells. LFGTE developers and their tax consultants must carefully review these PLRs as they often change the qualifying criteria for well fields upgraded or modified after 1992 and 1998.

Maximum value can be obtained from what remains of the Section 29 tax credit by:

- Focusing on landfills which have 2007 well fields; and
- Focusing on landfills which had comprehensive pre-1998 horizontal LFG collection system coverage (with expected refuse overfill).

The latter consideration is of value since the “grandfathered” LFG extraction facilities will in most instances be capable of collecting part or all of the LFG being provided by the overfill.

Renewable Energy Production Incentive

The Renewable Energy Production Incentive (REPI) was authorized under Section 1212 of the Energy Policy Act of 1992. REPI is administered by the Department of Energy (DOE). REPI provides an incentive payment of 1.5 ¢/kWh (1993 dollars) with annual increases for inflation for electric power produced by qualifying energy facilities. Qualifying facilities are those:

- Owned by state and local governmental entities (including municipal utilities);
- That have commenced operation between October 1, 1993, and no later than September 30, 2003; and
- Where the source of the electricity is a renewable energy source. LFG is a qualifying renewable energy source.

Payments are made for a 10-year period commencing with the first year claimed. The amount of money available for REPI is established every year by Congressional appropriation. If insufficient funds are available to fund all applications, the funds are divided amongst the applicants. Power generation not reimbursed in a given year can be rolled over into future years. The funding is prioritized by project type. Tier 1 projects employ solar, wind, geothermal, or closed, loop biomass technologies. Tier 2 projects include other renewable technologies including LFG. Tier 1 projects receive first priority for 100 percent funding.

DOE has adopted a fairly broad definition for the term “state and local government.” The definition includes, for example, schools and public authorities. The University of California at Los Angeles (UCLA) has claimed REPI benefits since 1994. It is not necessary that the power generation unit be 100 percent LFG fired. The fraction of the total kWhs produced on LFG can be calculated, and the REPI can be claimed on the LFG fired fraction. There is no minimum LFG fraction required.

In 1994 and 1995, sufficient appropriations were made by Congress to fund all Tier 1 and Tier 2 projects at 100 percent. Since 1996 only Tier 1 projects were funded at 100 percent. Tier 2 projects received partial payments on a prorated basis. Full funding of REPI applications would currently require an annual appropriation level in the range of \$8,000,000 to \$9,000,000. Recent annual appropriations have been in the range of \$1,500,000 to \$4,000,000.

A new LFG fired project now theoretically qualifies for well over 1.5¢/kWh. It is not possible to determine how much a new LFG fired project will actually receive since: (1) the total funding level varies each year; (2) the number of new projects and their Tier 1 versus Tier 2 mix in a given year is unknown; and (3) it is difficult to calculate the impact of the moving inventory of partially funded kWhs from prior years. Based on recent funding levels, REPI could probably currently contribute less than 0.5¢/kWh to new LFG fired projects.

Pending Federal Initiatives

Over the last 4 years, the LFGTE industry has vigorously pursued an extension to Section 29 or an equivalent tax credit.

As of the date of this report, several proposals were pending in Congress to extend LFGTE tax credits in some form. A tax credit in the range of 1.5¢ per kWh (or its equivalent for projects with gas as their product) is common to several proposals.

3.1.2 State

California has a comprehensive package of incentives and subsidies to aid renewable energy electric power projects. The incentives and subsidies grew out of California's program to deregulate its electric power industry and recent efforts to stimulate power production and/or reduce energy consumption.

The principal vehicle for assisting renewable energy projects is the Renewable Resource Trust Fund. The program is administered by the California Energy Commission (CEC). The fund has four accounts:

1. Existing Renewable Resources Account;
2. New Renewable Resources Account;
3. Emerging Renewable Resources Account; and
4. Customer-Side Renewable Resource Purchases Account.

The first account provides a subsidy for existing projects when the power sales rate of existing projects falls below a specified benchmark price. The second account pays a fixed subsidy of up to 1.5¢ per kWh for new projects (for a five year period). The actual price paid for a specific project is determined through submitting a winning bid for a subsidy through auctions periodically administered by the CEC. The third account will provide capital cost grants equal to the lesser of 50 percent or \$4,000/kW for specific emerging technologies. As of June 2001, the fuel cell is the only technology which could utilize LFG which could qualify for the emerging renewable resources account. Complete information on the assistance available through the Renewable Resource Trust Fund can be found on the CEC web site (www.energy.ca.gov).

Other State programs which could and can provide assistance to LFGTE projects include:

- **Self-Generation Program** – The program is administered by SCE, PG&E, the San Diego Energy Office, and the Southern California Gas Company for cogeneration projects under 1 MW. The program provides 30 percent to 50 percent grants for projects satisfying specific conditions. Information can be found at the web sites for the program administrators. The program would apply only to LFGTE projects which are by definition cogeneration projects. Few LFGTE projects are cogeneration projects, but occasionally a cogeneration project could be configured;

- **Innovative Peak Load Reduction Program** – The program is administered by the CEC and can provide a \$250/kW (net) grant to LFGTE projects. Information on this program can be found at the CEC web site.
- **Public Agency Loan Program** – The program is administered by the CEC and provides 3 percent loans to municipalities, public agencies and not-for-profit hospitals for renewable energy or cogeneration facilities. Information on this program can be found at the CEC web site.

3.1.3 Greenhouse Gas Credits

LFG consists of about 55 percent methane by volume. Methane is 21 times more potent as a greenhouse gas (GHG) than CO₂ on a mass basis. The capture and combustion of LFG in a flare results in a significant net reduction in GHG emissions on a CO₂ equivalent basis.

The electric power generation industry, and other major CO₂ producers in the United States, will have a difficult task in complying with international agreements intended to lower GHG emissions. Under certain conditions, LFG could be converted into transferable GHG emission reduction credits. The cost of producing credits through LFG control could be less than the cost of many other methods of producing GHG emission reduction credits.

If LFG is collected and flared, a GHG emission reduction credit is produced by converting methane to CO₂. LFG flares are designed to achieve at least a 98 percent destruction of methane. Each tonne of methane burned results in the net production of 21 tonnes of CO₂ emission reduction credits. If the methane is beneficially used to displace a fossil fuel, then additional emission reduction credits can be taken for each tonne of LFG methane destroyed.

At the present time, a formal market for GHG does not exist in the United States; however, a few isolated GHG emission reduction credit sales have occurred. These sales were reportedly in the range of \$0.50 to \$2.00/tonne of CO₂ equivalent. Sale of GHG emission reduction credits may provide a future source of revenue to support LFGTE projects.

3.2 Ownership and Financing of LFGTE Project Elements

3.2.1 Landfills

Landfills are either publicly or privately owned. Public entities owning landfills include cities, counties, authorities or special purpose districts. Privately owned landfills are owned by one of the major national waste management firms or by firms which own one or a few landfills. All three of the major waste management firms -- Waste Management, Allied and Republic -- own landfills in California.

3.2.2 LFG Collection and Control Systems

LFG collection and control systems are usually owned by the owner of the landfill. In some instances, particularly the older LFGTE projects, the developer of the LFGTE project installed and owns the LFG collection and control system. In such instances, the LFG rights lease called

for the developer to install the well field necessary to support his project. In many of these cases, the landfill owner has installed a supplementary well field beside or around the developer's well field. The supplementary well field was required to fully satisfy the landfill owner's regulatory responsibilities. The well field supplying the LFGTE facility was not extensive enough to collect all of the LFG that could be recovered. On these landfills, there are two well fields -- one owned by the owner of the LFGTE facility and one owned by the landfill owner. The LFG collected by the landfill owner's well field is flared.

It is also possible for a well field installed by the landfill owner to be under the temporary ownership of the owner of the LFGTE facility. If the well field predates the LFGTE facility, it is common for the well field to be leased or sold to the LFGTE project developer in the LFG rights agreement. This allows the LFG developer (or a third party) to become the gas producer and allows him to claim Section 29 tax credits.

3.2.3 Energy Conversion/Generation Systems

LFGTE facilities can be owned by the landfill owner or by an independent developer. Since landfills are both publicly and privately owned, LFGTE facilities which are owned by a landfill owner can be either privately or publicly owned. Independent developers are always private sector firms.

For most private sector LFGTE facility power generation projects, it is common to form a Gasco (gas producer company) and a Genco (power production company). This arrangement is necessary to obtain Section 29 tax credits. The Gasco/Genco arrangement is not necessary if the private sector owner of the landfill retains the ownership of the well field, sells LFG to the LFGTE facility developer, and claims the tax credits for himself. It is also not necessary to form a separate Gasco if the product of the LFGTE facility is medium-Btu or high-Btu gas, and if the product gas is sold to an unrelated party.

3.3 Financial Expectations of Investors

3.3.1 Municipal Financing

If a LFGTE project is owned and operated by a municipal governmental body (e.g., city or county) or by a governmental agency (e.g., authority or special purpose district), then the cost of money for a LFGTE project is equal to the municipal body's cost of funds. The municipal cost of money is less than the cost of private money. The municipal cost of money has been in the range of 5 percent to 8 percent in recent years for 10- to 15-year loans.

The minimum expectation of a municipal body would be that the funds expended to finance a project would pay back the investment at the municipality's cost of money. In most cases, a municipality would expect to see a cost savings over this minimum return. The premium would provide a cushion against actual project performance below anticipated project performance.

A municipality would commonly conduct an analysis of project economic viability by selecting a minimum acceptable interest rate (i.e., 10 percent) and then run a traditional net present value or annual cost analysis to determine whether or not the project would yield a positive net present worth or a positive cumulative cash flow.

3.3.2 Private Sector Developers

The cost of money for a privately financed project is greater than the cost of money for a municipally financed project. Corporations or individuals can invest equity (available cash) or can incur debt to finance a project. Debt can be backed by the full strength of the investor's balance sheet or the loan can be project-specific or subsidiary-specific with no collateral offered other than the assets of the project itself. The latter mechanism is known as "project finance", "off balance sheet financing", or a "non-recourse" loan.

Equity and balance sheet debt are generally valued equally by private investors since the amount of balance sheet debt which they can carry at any point in time is limited. A private investor must decide how to utilize his limited resources. Most private investors have investment alternatives not only in the LFGTE industry, but also investment opportunities in other industries. The lowest rates of return on investment are often demanded by utility subsidiaries, since utilities have historically seen low rates of return from their regulated businesses. Independent firms or firms which are owned by non-utility companies generally demand the higher rates of return seen in unregulated private industry.

Rates of return demanded by the private sector typically range from 15 percent to 25 percent. The expected rate of return is projected from a multi-year pro forma projection, which incorporates an internal rate of return calculation. The minimum rate of return that a private entity has at any point in time is often called its "hurdle rate". If the projected rate of return exceeds the firm's hurdle rate, then the firm proceeds with project development.

Project finance involves a mix of equity and debt. A typical ratio of equity to debt is 20 percent/80 percent. The developer applies his hurdle rate only against the equity fraction. Project finance accomplishes two goals:

- It allows the private investor to leverage his limited equity (or equity equivalent) and undertake more projects; and
- It makes less attractive projects more viable since the interest rate on a project finance loan is virtually always lower than a firm's hurdle rate. In effect, the margin from the debt fraction subsidizes the equity fraction, producing a higher rate of return on the equity.

The next subsection, titled "Independent Lenders", discusses the project finance concept in greater detail.

3.3.3 Independent Lenders

Independent lenders will provide financing in the form of balance sheet debt or the form of project finance debt. Balance sheet debt is offered based on the overall financial strength and assets of a borrower, with varying degrees of consideration given to the financial viability of the project(s) that is (are) to be undertaken with the loan. For large, profitable companies with substantial assets, the lender may not be greatly concerned with the specifics of the project(s) to be financed. A lender's interest level in the details of the specific project(s) to be financed increases as the potential underperformance of the project(s) begins to have a significant impact on the borrower's ability to repay the loan. Many private LFGTE developers are highly leveraged or have limited financial support from their parent company, and often a true balance

sheet loan cannot be obtained. A true balance sheet loan (e.g., one fully backed by a utility company parent of a LFGTE development subsidy) would probably be offered at 2 percent to 3 percent above prime rate.

Project finance (sometimes called off-balance sheet or non-recourse loans) requires extensive due diligence by the lender. Since the loan is guaranteed only by the project's performance and is collateralized only by the project's assets, the lender must satisfy himself that the project has no fatal flaws, and believe that the projections of financial performance made by the borrower are realistic. The projections are summarized on a pro forma.

The pro formas to support project finance loans show an equity and debt fraction. Equity is similar to the down payment on a mortgage. An equity fraction of 20 percent is common for project finance loans. The lender also wants to see that cash is available each year in excess of the amount required to service the debt. The excess is known as "coverage." Lenders typically require that coverage exceed 20 percent of debt service during the life of the loan. The term of a project finance loan is generally in the range of 10 to 15 years. The interest rate for a project finance loan is about 4 percent to 5 percent over prime.

It should be noted that in addition to the above lender requirements, the borrower will evaluate the internal rate of return on the equity he invests. The minimum required internal rate of return on the equity fraction is typically in the 15 percent to 25 percent range.

A project finance transaction generally requires a great deal of legal, accounting and technical support. The level of effort does not vary greatly with the size of the loan. Project finance is usually seen only on large projects or for a portfolio of smaller projects. Project finance can be facilitated by building the projects with equity or a balance sheet loan, and then converting to project finance after the project is operating.

3.4 Alternatives for Selling Power in California

As of July 2001, the date this report was prepared, the power sales market in California was in flux. California has taken measures, and will take measures, to solve problems that sprung from its deregulation of the electric industry. The subsections which follow discuss circumstances and opportunities as of July 2001.

3.4.1 Retail Deferral

The "best customer" for a LFGTE project is the host landfill itself. Maintenance shops, office buildings, scale houses, LFG blower/flare stations, groundwater and storm water pumps, and leachate treatment facilities are among the typical consumers of power. Other waste management facilities, such as transfer stations or recycling facilities, are sometimes located at a landfill. Occasionally, other potential retail customers (industrial facilities, office buildings, commercial structures, shopping centers, or public buildings) are located contiguous to or close to landfills.

The advantage of retail deferral, over other options for power sale, is that the base price is the utilities retail rate. Retail rates for large customers in California are in the range of 12¢ to 13¢ per kWh. When power is self-generated, it is necessary to rely on the local utility for "standby" power. Power generation facilities are not capable of operating 100 percent of the time. Down

time takes the form of planned and unplanned outages. As of June 2001, the CPUC was investigating standby rates as they pertain to distributed generation projects. The outcome of this proceeding is unknown; however, it is expected that standby charges for distributed generation projects will be reduced.

The cost of “standby” power typically reduces the effective net deferred cost by 10 percent to 20 percent. The specific impact must be calculated through application of the local utility’s standby power rate schedule. Prior to the recent disruption of the deregulated market in California, retail customers leaving SCE and PG&E were required to pay a competition transition charge (CTC), which was scheduled to expire no later than 2003. The CTC was eliminated for SDG&E customers in July 2000 since it was determined that SDG&E had recovered its “stranded costs.” When SCE and PG&E began to pay more for power than they could recover from their rates, the CTC, because of the way it is calculated, ceased to exist. The future status of the CTC or other exit charges is currently unknown, and will not be known until all elements of the power industry recovery package are in place.

The power requirements at a landfill are generally much lower than the power generation potential at a landfill. Some of the power requirements at a landfill are intermittent (e.g., a recycling facility which only operates eight to ten hours per day).

If an independently owned facility is located on property immediately contiguous to the landfill, it is permitted to directly sell the facility power (with a direct power line to the facility). If a facility is not continuous to the landfill, it is not possible to run a direct power line to the facility. An alternative to the direct power line is to construct a medium-Btu pipeline to the customer and to locate the LFGTE power plant at the customer’s site. Power sales to off-site customers are discussed further under the subsection titled “Bilateral Contracts”.

The limited revenue opportunity associated with on-site deferral can be handled in two ways:

- Construct a small project which is sized to satisfy on-site loads (such projects will generally be in the 30 kW to 300 kW range); or
- Build a large project and credit this 30 kW to 300 kW of consumption to the larger project. In all but the most stressed market conditions (such as those recently experienced in California), retail deferral has greater value than sale to the market.

3.4.2 Long-Term Contracts

As of July 2001, California’s investor owned utilities were entering into power purchase agreements only for projects less than 100 kW in size. The contracts are as-delivered contracts and do not provide capacity payments. The rate paid for the power varies monthly and represents the utility’s short run avoid cost (SRAC). The SRAC is directly pegged to natural gas cost. These contracts are continuously available and offer a convenient way for a very small LFGTE project to sell excess power. The contracts do not have the comfort of offering a fixed price.

Contracts for larger projects are only being offered by California’s Department of Water Resources (DWR). As a result of the questionable creditworthiness of the California IOUs, DWR has stepped in as the short-term and long-term buyer of power. It has been reported that

DWR has been signing 10-year contracts at an average price of 7¢ per kWh; however, the details of the agreements are considered to be confidential.

DWR has been concentrating on securing large blocks of power, and to date has had no preference for “green” power over “brown” power. Projects less than 10 MW in size do not appear to be large enough to be of interest to DWR as of June 2001. If DWR is installed as the long-term purchaser of power, DWR might develop standard offer type contracts for small generators. In the interim, it appears as if only large projects or developers who are able to aggregate several projects could obtain a contract with DWR.

The creditworthiness of public utilities (e.g., LADWP and SMUD) and public power agencies has not been called into question and these entities continue to purchase their own power. The procurement methodology at public utilities varies, and in some cases it may only be possible to obtain a contract through a formal request for proposal/bid process. LADWP has specific interest in green power, and they are willing to pay a premium for green power. Additional information on green power sales can be found in the subsection titled “Green Power Sales Opportunities”.

3.4.3 Sale to the Spot Market

With the termination of the State-related power exchange (PX) in February 2001, a great deal of fluidity left the California power market. The power market as of June 2001 largely consisted of the Automated Power Exchange (APX) and the State-related Independent System Operator (ISO) shortfall purchases. If an owner of a LFGTE project intends to sell power to the open market, the following steps would need to be taken:

- Register with the ISO as a participating generator. The generator must be responsible for at least 1 MW of gross capacity;
- Install an ISO-approved meter at the facility (or facilities);
- Obtain a power marketing license from FERC; and
- Sign an agreement with a power market (such as the APX).

3.4.4 Bilateral Contracts

A bilateral contract is a power sales contract between a generator and a retail customer. Power sale to a customer located adjacent to a landfill or at an off-site location through a medium-Btu pipeline project would be covered by a bilateral agreement. A second form of a bilateral agreement would be one between a generator and a customer not directly connected to the generator. The power which is sold would travel through the utility grid. In order to consummate such a transaction, even when only one retail customer is involved, the generator would be required to register as an energy services provider with the CEC, register with the ISO, and install an ISO-approved meter. As of June 2001, the elimination of direct retail sales was being discussed as a component of the effort to restructure the California utility industry.

3.4.5 Green Power Sales Opportunities

Direct Subsidies

Some states, particularly those which have or will undergo deregulation of their power industry, can or may provide transitional assistance to the renewable power industry. California is such a state. The California direct subsidy program was previously discussed.

Market-Based Support

There is some market-based support for renewable energy on the retail level in the form of customers willing to pay a premium for greenpower. Some cities, companies or government agencies have made commitments to buy greenpower, and some residential customers are attracted to greenpower. Greenpower reaches customers in two ways: (1) power marketers in states with a deregulated power industry often sell renewable power in addition to “brown” power to retail customers; and (2) some utilities in regulated markets offer their retail customers a renewable power purchase option. As of late-2000, greenpower was being marketed by retailers in six states (California, Pennsylvania, Maine, New Jersey, Massachusetts, and Connecticut). In early-2001, in a notable reversal for greenpower, major greenpower retailers in California abandoned the retail market and returned their customers to their respective IOUs. At the present time, only selected municipal suppliers, such as Los Angeles Department of Water and Power (LADWP), offer a greenpower option to their retail customers.

Greenpower on California’s Automated Power Exchange (APX) traded at a premium of only about 0.3¢/kWh above brown power over the last 2 years. It will probably take several years before greenpower premiums make much of an impact on the LFGTE industry. Greenpower demand must first outstrip greenpower supply. In the current California market, LFGTE does not experience a direct financial benefit simply because it is greenpower. It is expected that this will change over time.

Current Green Power Sales Opportunities

As discussed above, revenue enhancement through greenpower sale offers limited potential at the present time; however, there are currently three ways for LFGTE projects to sell greenpower:

- Respond to utility greenpower RFPs;
- Enter into contracts with companies who retail greenpower; and
- Execute bi-lateral contacts with large power users who have a commitment to greenpower.

The LADWP recently issued a RFP for the procurement of greenpower. Price is a major consideration in this and other RFPs. A wealth of up-to-date information on greenpower marketing can be found at www.eren.doe.gov.

Appendix I Tables

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**TABLE 1
EXISTING LFGTE PROJECTS IN CALIFORNIA**

Landfill Name	City	Current Status	MSW In Place (tons)	Landfill Owner Type	Power Generation Capacity		Medium-Btu Capacity	
					MW	MWh/Yr	MMscfd	MMBtu/Yr
Acme Landfill	Martinez	Operational	10,700,000	Private		---	1.8	328,500
Altamont Landfill	Livermore	Operational	26,450,512	Private	6.6	57,816.00		---
American Canyon Landfill	Napa	Operational	4,200,000	Public	1.5	13,140.00		---
Austin Road Landfill	Stockton	Operational	2,030,690	Public	0.8	7,008.00		---
Bailard Landfill	Oxnard	Operational	4,336,609	Public	0.0	---		---
BKK Landfill-Phase I	West Covina	Operational	46,000,000	Private	6.0	52,560.00		---
BKK Landfill--Phase II	West Covina	Operational	46,000,000	Private	6.0	52,560.00		---
Bradley Landfill	Sun Valley	Operational	23,000,000	Private	0.0	---		---
Central Landfill	Petaluma	Operational	9,575,690	Public	3.2	28,032.00		---
City of Santa Clara Landfill	Santa Clara	Operational	3,500,000	Public	1.4	12,264.00		---
City of Sunnyvale	Sunnyvale	Operational	2,300,000	Public	1.6	14,016.00		---
Coastal Landfill	Oxnard	Operational	3,300,000	Public	0.0	---		---
Coyote Canyon Landfill	Irvine	Operational	25,000,000	Public	17.0	148,920.00		---
Crazy Horse Landfill	Prunedale	Operational	1,855,351	Public	1.4	12,264.00		---
Davis Street Landfill	San Leandro	Operational	9,700,000	Public		---	1.4	255,500
Guadalupe Disposal Site	San Jose	Operational	5,500,000	Private	2.5	21,900.00		---
Industry Hills	Industry	Operational	1,500,000	Public		---	0.5	91,250
Lopez Canyon Landfill	San Fernando	Operational	16,700,000	Public	6.0	52,560.00		---
Menlo Park Landfill	Menlo Park	Operational	5,000,000	Public	2.0	17,520.00		---
Miramar Landfill--Phase I	San Diego	Operational	29,000,000	Public	6.0	52,560.00		---
Miramar Landfill--Phase II	Sand Diego	Operational	29,000,000	Public	4.0	35,040.00		---
Monterey Peninsula Landfill	Marina	Operational	5,500,000	Public	1.2	10,512.00		---
Mountaingate Landfill	Los Angeles	Operational	10,000,000	Private		---	3.0	547,500
Newby Island Landfill--Phase I	San Jose	Operational	19,900,000	Private	5.0	43,800.00		---
Olinda Landfill--Phase I	Brea	Operational	32,981,156	Public	5.7	49,932.00		---
Otay Landfill	Chula Vista	Operational	8,099,138	Private	3.7	32,412.00		---
Palo Alto Landfill	Palo Alto	Operational	2,700,000	Public	2.0	17,520.00		---

TABLE 1
EXISTING LFGTE PROJECTS IN CALIFORNIA

Landfill Name	City	Current Status	MSW In Place (tons)	Landfill Owner Type	Power Generation Capacity		Medium-Btu Capacity	
					MW	MWh/Yr	MMscfd	MMBtu/Yr
Palos Verdes Landfill	Rolling Hills	Operational	23,000,000	Public	9.0	78,840.00		---
Penrose Landfill	Sun Valley	Operational	9,000,000	Private	9.3	81,468.00		---
Placer County Western Regional	Roseville	Operational	2,300,000	Public	1.1	9,636.00		---
Prima Deshecha Landfill	San Juan Capistrano	Operational	7,400,000	Public	6.0	52,560.00		---
Puente Hills Landfill (Steam Cycle)	Whittier	Operational	78,142,152	Public	50.0	438,000.00		---
Puente Hills (Gas Turbines)	Whittier	Operational	78,142,152	Public	4.0	35,040.00		---
Puente Hills (Rio Hondo)	Whittier	Operational	78,142,152	Public		---	0.2	36,500
Sacramento City Landfill	Sacramento	Operational	3,900,000	Public		---	1.2	219,000
San Marcos Landfill--Phase I	San Marcos	Operational	11,494,445	Public	1.3	11,388.00		---
Santa Clara Landfill	Oxnard	Operational	270,000	Public	5.6	49,056.00		---
Santa Cruz City Landfill	Santa Cruz	Operational	2,040,427	Public	0.7	6,132.00		---
Scholl Canyon Landfill	Glendale	Operational	22,511,265	Public		---	9.0	1,000,000
Sheldon-Arleta Landfill	Sun Valley	Operational	5,500,000	Public	0.0	---		---
Spadra Landfill	Pomona	Operational	12,500,000	Private	9.6	84,096.00		---
Sycamore Landfill	Santee	Operational	9,163,739	Public	1.5	13,140.00		---
Tajiguas Landfill	Santa Barbara	Operational	7,000,000	Public	3.8	33,288.00		---
Temescal Road Landfill	Corona	Operational	4,000,000	Public	2.0	17,520.00		---
Toyon Canyon Landfill	Los Angeles	Operational	16,000,000	Public	9.0	78,840.00		---
Visalia Disposal Site	Visalia	Operational	3,500,000	Public	1.6	14,016.00		---
West Contra Costa Landfill	Contra Costa	Operational	10,105,056	Private	3.0	26,280.00		---
Woodville Disposal Site	Woodville	Operational	1,580,000	Public	0.8	7,008.00		---
Yolo County Central Landfill	Davis	Operational	8,427,340	Public	2.4	21,024.00		---
					204.3	1,789,668.00	17.1	2,478,250

Notes:

- (1) Bradley Landfill and Sheldon-Arleta Landfill send LFG to a power plant at Penrose Landfill.
- (2) Bailard Landfill and Coastal Landfill send LFG to a power plant at Santa Clara Landfill.
- (3) Scholl Canyon's LFG is conveyed to the City of Glendale's Grayson Station, where it is co-fired with natural gas to produce about 10 MW in a 50 MW steam cycle plant.
- (4) Mountaingate's LFG is conveyed to UCLA, where it is co-fired with natural gas to produce about 6 MW in a 16 MW combustion turbine cogeneration facility.

TABLE 2
POTENTIAL LFGTE PROJECTS IN CALIFORNIA

Landfill Name	City	Current Status	MSW In Place (tons)	Landfill Owner Type	Power Generation Capacity		Medium-Btu Capacity	
					MW	MWh/Yr	MMscfd	MMBtu/Yr
Amador Country Landfill	Ione	Potential	1,013,553	Public	0.8	7,008		-
American Canyon--Phase II	Napa	Potential	482,541	Public	0.8	7,008		-
Anderson	Anderson	Potential	1,554,000	Private	1.6	14,016		-
Arvin Landfill	Arvin	Potential	3,700,000	Public	2.4	21,024		-
Azusa Land Reclamation	Azusa	Planned	7,900,000	Private	3.0	26,280		-
B & J Landfill	Vacaville	Potential	780,000	Private	1.6	14,016		-
Badlands Disposal Site	Moreno Valley	Planned	1,720,000	Public	0.8	7,008		-
Bakersfield Metropolitan	Bakersfield	Potential	1,405,607	Public	1.2	10,512		-
Ben Lomond Solid Waste	Ben Lomond	Potential	1,200,000	Public	0.8	7,008		-
Blythe Disposal Site	Blythe	Planned	3,864,000	Public	1.6	14,016		-
Bonzi Landfill	Modesto	Potential	1,800,000	Private	0.8	7,008		-
Bradley Landfill	Los Angeles	Potential	23,000,000	Private	6.0	52,560		
Buena Vista Disposal Site	Watsonville	Planned	1,250,046	Public	0.8	7,008		-
Calabasas Landfill	Agoura Hills	Planned	10,000,000	Public	10.0	87,600		-
California Street Landfill	Redlands	Potential	960,000	Public	0.8	7,008		-
Chateau Fresno Landfill	Fresno	Potential	13,451,139	Private		---	3	547,500
Chestnut Avenue Landfill	Fresno	Potential		Private	0.8	7,008		-
China Grade Landfill	Bakersfield	Potential	1,639,000	Public	0.8	7,008		-
Chiquita Canyon Landfill	Valencia	Planned	10,500,000	Private	7.6	66,576		-
City Garbage (Cummings)	Eureka	Potential	1,740,000	Private	2.5	21,900		-
City of Paso Robles Landfill	Paso Robles	Potential	870,000	Public	0.8	7,008		-
City of Santa Maria	Santa Maria	Potential	1,809,995	Public	0.8	7,008		-
City of Ukiah	Ukiah	Potential	2,200,000	Public	1.6	14,016		-
Coachella Valley Disposal Site	Coachella	Planned	3,237,000	Public	1.6	14,016		-
Cold Canyon Landfill	San Luis Obispo	Potential	2,254,575	Private	1.6	14,016		-
Colton Refuse Disposal Site	Colton	Operational	6,500,000	Public	3.0	26,280		-
Corral Hollow Landfill	Tracy	Potential	690,000	Public	0.8	7,008		-

TABLE 2
POTENTIAL LFGTE PROJECTS IN CALIFORNIA

Landfill Name	City	Current Status	MSW In Place (tons)	Landfill Owner Type	Power Generation Capacity		Medium-Btu Capacity	
					MW	MWh/Yr	MMscfd	MMBtu/Yr
Crescent City Landfill	Crescent City	Potential	806,400	Public	0.8	7,008		-
Double Butte Disposal Site	Winchester	Planned	1,977,463	Public	0.8	7,008		-
Earlimart Disposal Site	Earlimart	Potential	782,400	Private	0.8	7,008		-
Eastern Regional Landfill	Truckee	Potential		Public	0.8	7,008		-
Edom Hill Disposal Site	Cathedral City	Planned	4,316,700	Public	1.6	14,016		-
El Sobrante Landfill	Corona	Potential	4,900,000	Private	3.0	26,280		-
Fink Road Landfill	Crows Landing	Potential	1,142,398	Public	0.8	7,008		-
Foothills Landfill	Bellota	Planned	3,766,595	Public	1.6	14,016		-
Frank R. Bowerman Landfill	Irvine	Planned	12,900,000	Public	4.8	42,048		-
Geer Road Landfill	Modesto	Potential	4,300,000	Public	2.4	21,024		-
Glenn County Landfill Site	Artois	Potential	540,000	Public	0.8	7,008		-
Hanford Landfill	Hanford	Potential	1,668,000	Public	1.2	10,512		-
Highgrove Landfill	Highgrove	Planned	4,000,000	Public	1.6	14,016		-
Highway 59	Merced	Potential	4,200,000	Public	2.4	21,024		-
Imperial Landfill	Imperial	Potential	802,060	Private	0.8	7,008		-
Keller Canyon Landfill	Pittsburg	Planned		Private	1.6	14,016		-
Lamb Canyon Disposal Site	Beaumont	Planned	2,279,000	Public	0.8	7,008		-
McCourtney Landfill	Grass Valley	Potential	2,182,268	Public	0.8	7,008		-
McFarland-Delano Landfill	Delano	Potential	1,071,000	Public	0.8	7,008		-
Mead Valley Disposal Site	Perris	Planned	2,312,000	Public	0.8	7,008		-
Mid-Valley Landfill	Rialto	Operational	6,200,000	Public	6.0	52,560		-
Milliken Landfill	Ontario	Operational	13,800,000	Public	8.0	70,080		-
Mountain View	Mountain View	Potential	11,800,000	Public	3.8	33,288		-
Newby Island Landfill--Phase II	Milpitas	Planned	19,900,000	Private	9.0	78,840		-
North County Landfill	Stockton	Potential	694,530	Public	0.8	7,008		-
Olinda Landfill--Phase II	Brea	Potential	32,981,156	Public	4.0	35,040		-
Ox Mountain Landfill	Half Moon Bay	Planned	10,000,000	Private	10.0	87,600		-

TABLE 2
POTENTIAL LFGTE PROJECTS IN CALIFORNIA

Landfill Name	City	Current Status	MSW In Place (tons)	Landfill Owner Type	Power Generation Capacity		Medium-Btu Capacity	
					MW	MWh/Yr	MMscfd	MMBtu/Yr
Potrero Hills Landfill	Fairfield	Planned	2,538,000	Private	3.0	26,280		-
Redwood Landfill	Novato	Potential		Private	3.0	26,280		-
Ridgecrest Landfill	Ridgecrest	Potential	1,300,000	Public	0.8	7,008		-
Sacramento County Landfill	Sacramento	Planned	15,000,000	Public	5.0	43,800		-
San Marcos Landfill--Phase II	San Marcos	Potential	11,494,445	Public	3.0	26,280		-
San Timoteo	Redlands	Operational	2,300,000	Public	2.0	17,520		-
Santiago Canyon	Irvine	Potential	14,275,570	Public	5.0	43,800		-
Savage Canyon Landfill	Whittier	Potential		Public	0.8	7,008		-
Shafter-Wasco Landfill	Shafter	Potential	1,400,000	Public	0.8	7,008		-
South Chollas Landfill	San Diego	Planned	4,750,000	Public	0.8	7,008		-
Southeast Regional	Selma	Potential			0.8	7,008		-
Sunshine Canyon	Sylmar	Planned	27,000,000	Private	9.0	78,840		-
Taft Landfill	Taft	Potential	1,261,106	Public	0.8	7,008		-
Teapot Dome Disposal Site	Porterville	Planned	1,614,000	Public	0.8	7,008		-
Tri-Cities Landfill	Fremont	Potential	7,915,544	Private	6.0	52,560		-
Tuolumne County Central Landfill	Jamestown	Potential	986,400	Public	0.8	7,008		-
Union Mine Disposal Site	El Dorado	Potential	1,900,000	Public	0.8	7,008		-
Upper Valley Disposal	Napa	Potential	570,000	Private	0.8	7,008		-
Vasco Road Landfill	Livermore	Planned	15,000,000	Private	4.8	42,048		-
Victorville Landfill	Victorville	Potential	600,000	Public	0.8	7,008		-
West Central Landfill	Redding	Potential	632,098	Public	1.6	14,016		-
Yuba-Sutter	Marysville	Potential	2,268,000	Private	1.2	10,512		-
					177.9	1,558,404		

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FIGURE 1
LANDFILL GAS UTILIZATION ALTERNATIVES

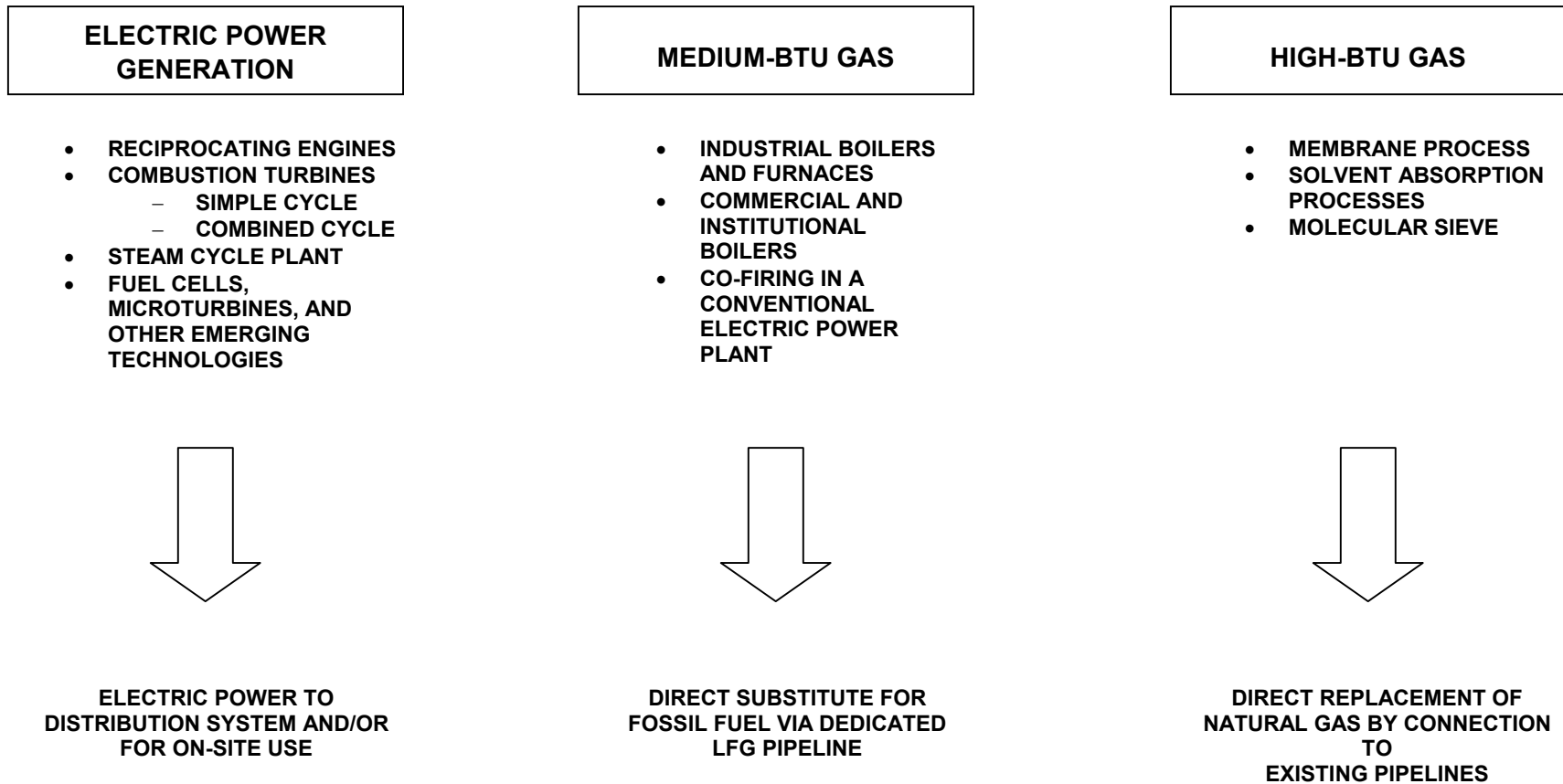


FIGURE 2
LANDFILL GAS CLEAN-UP PROCESS FOR MEDIUM-BTU GAS

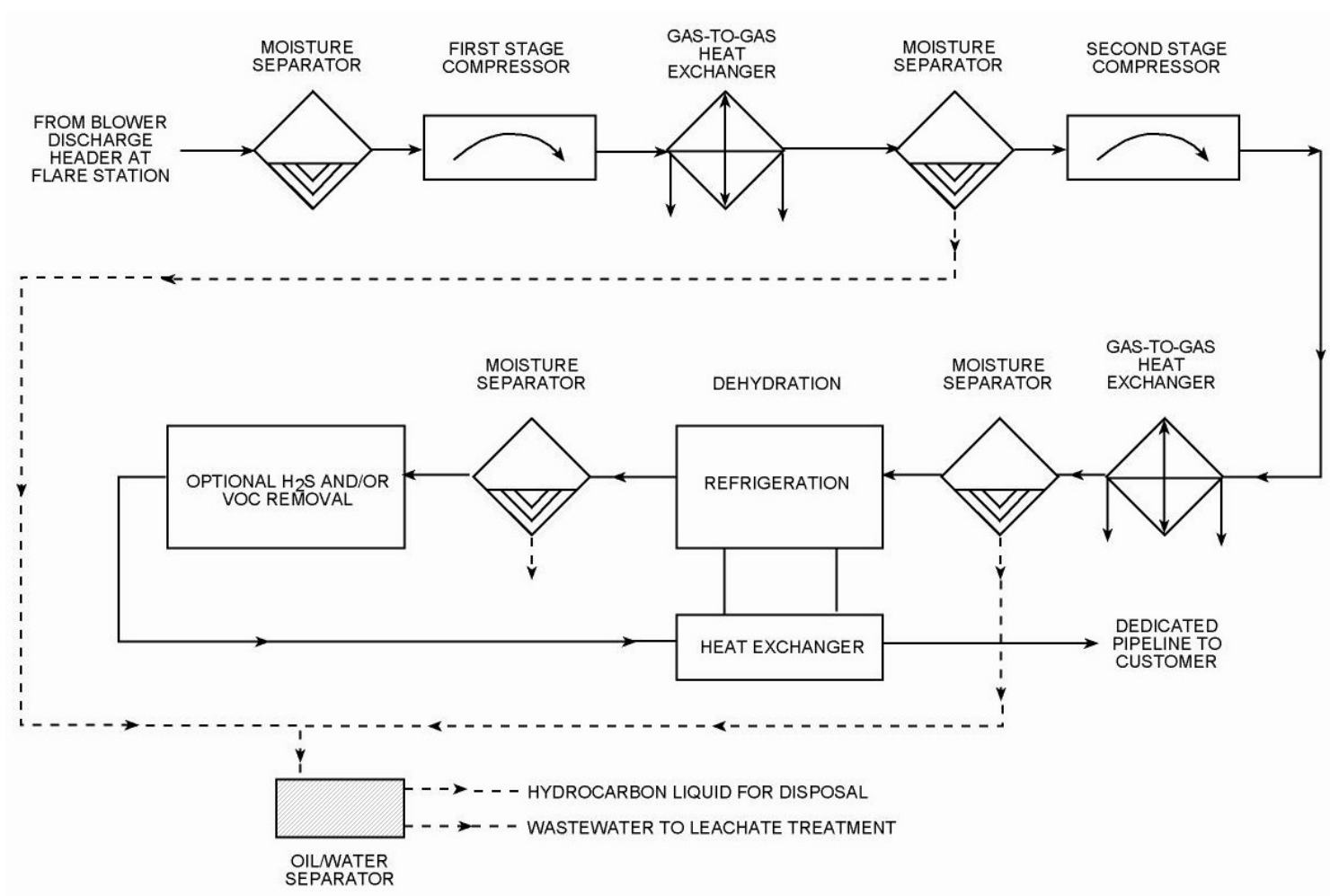
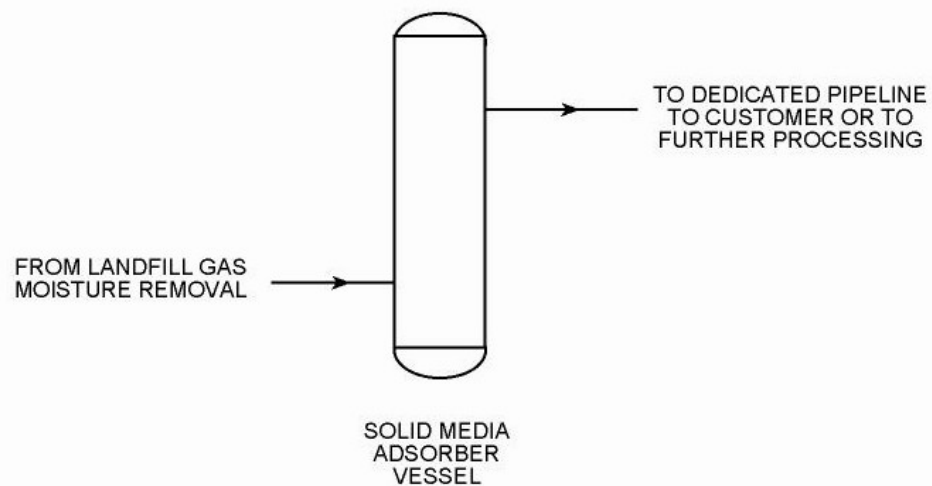


FIGURE 3
OPTIONAL LANDFILL GAS CLEAN-UP PROCESSES FOR H₂S REMOVAL

ALTERNATIVE NO. 1



ALTERNATIVE NO. 2

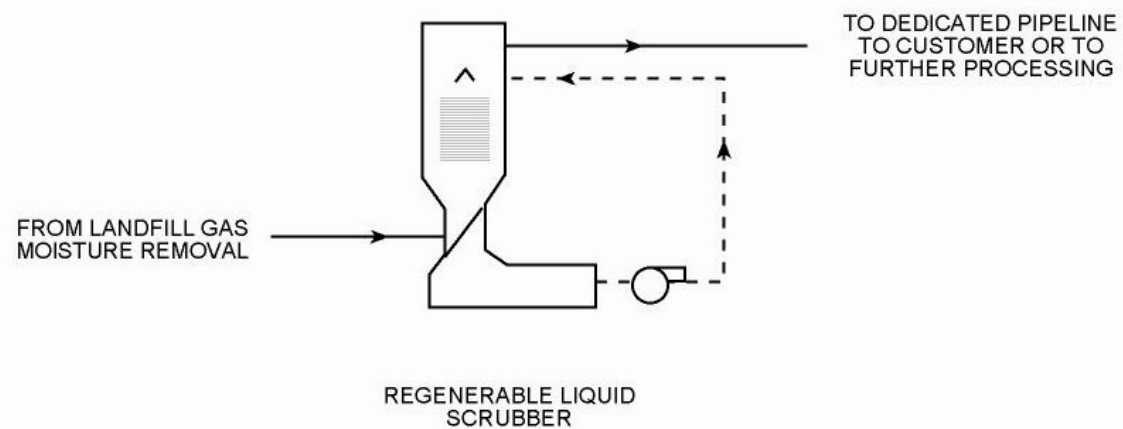


FIGURE 4
OPTIONAL LANDFILL GAS CLEAN-UP PROCESS FOR NMOC REMOVAL

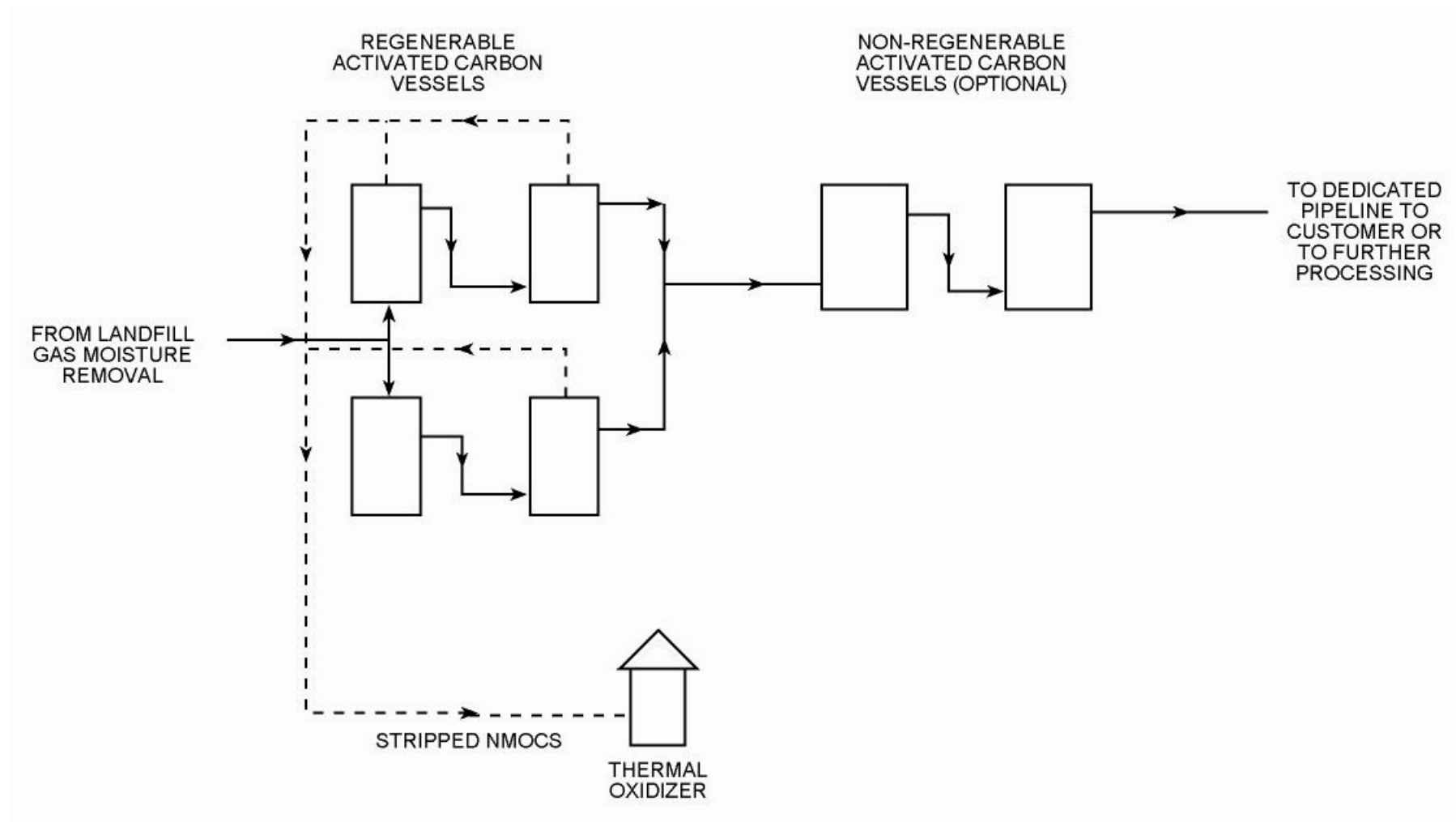


FIGURE 5
POWER GENERATION WITH RECIPROCATING ENGINES

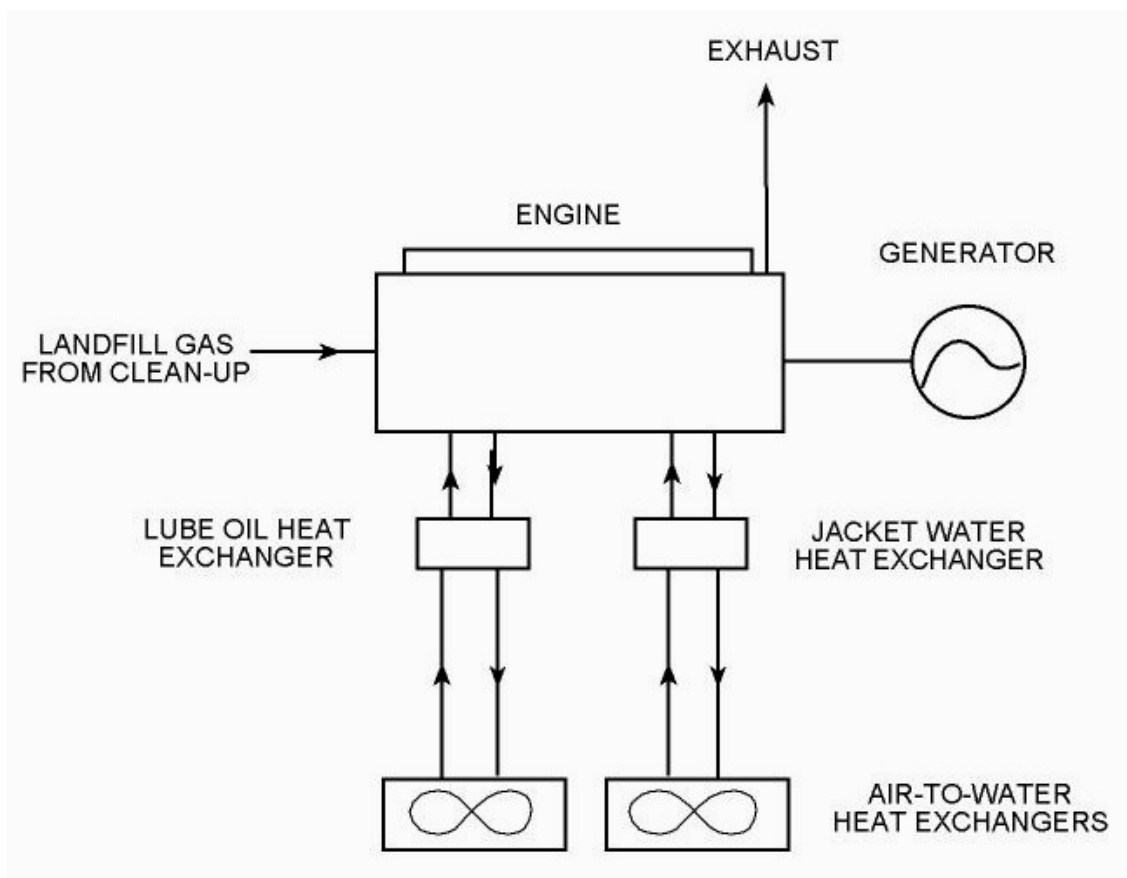


FIGURE 6
LANDFILL GAS CLEAN-UP PROCESS FOR RECIPROCATING ENGINES POWER GENERATION

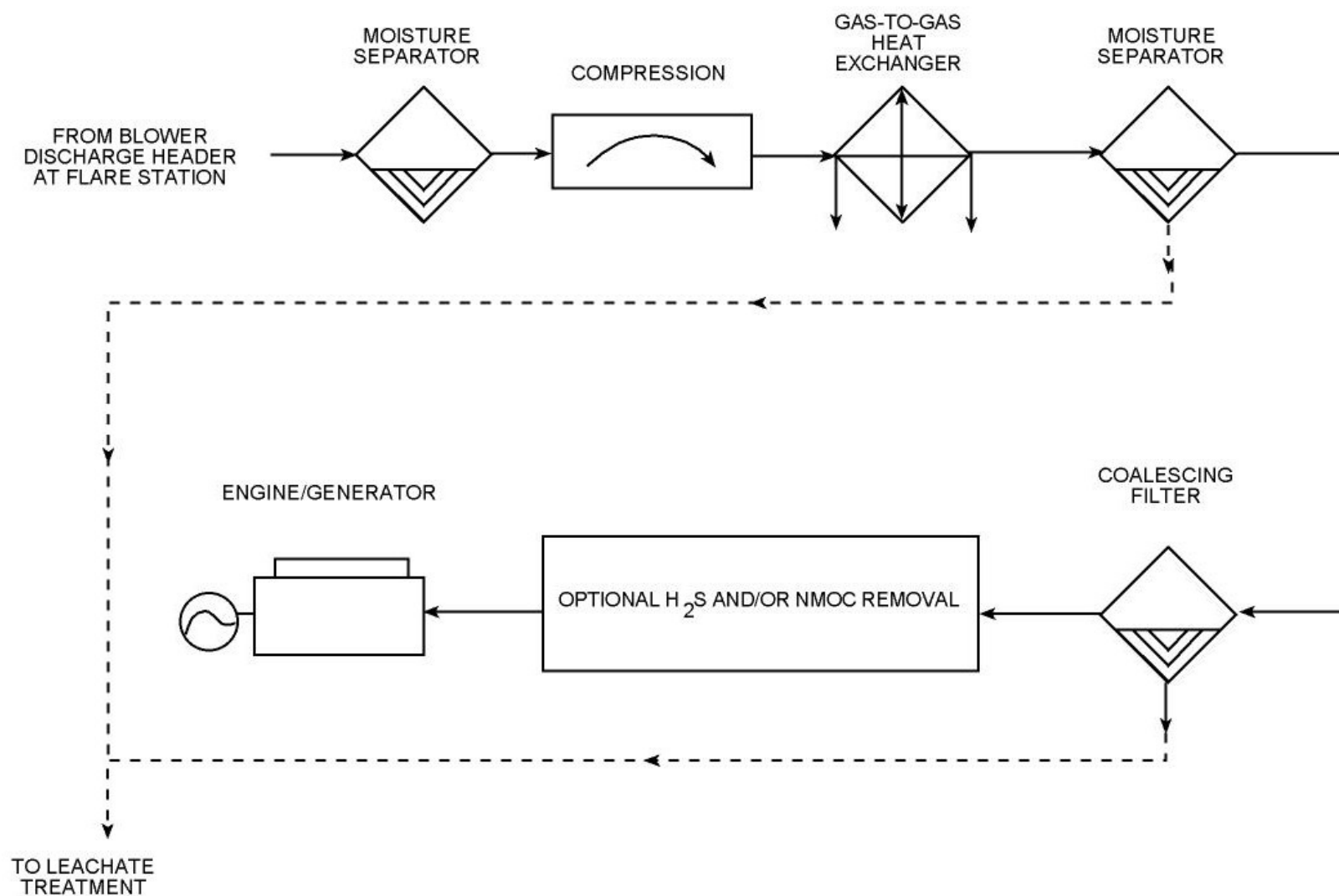
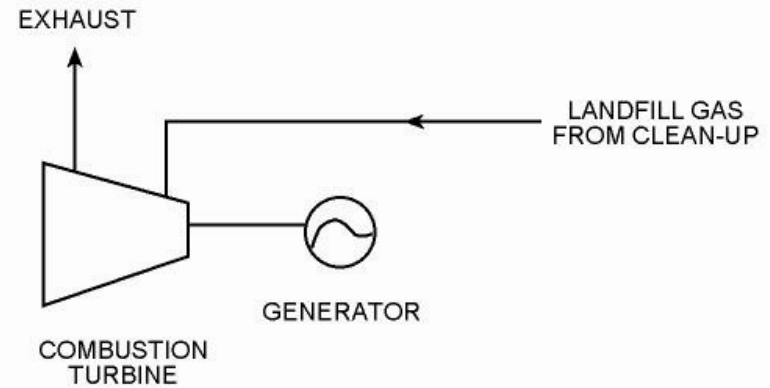


FIGURE 7
POWER GENERATION WITH COMBUSTION TURBINES

SIMPLE
CYCLE



COMBINED
CYCLE

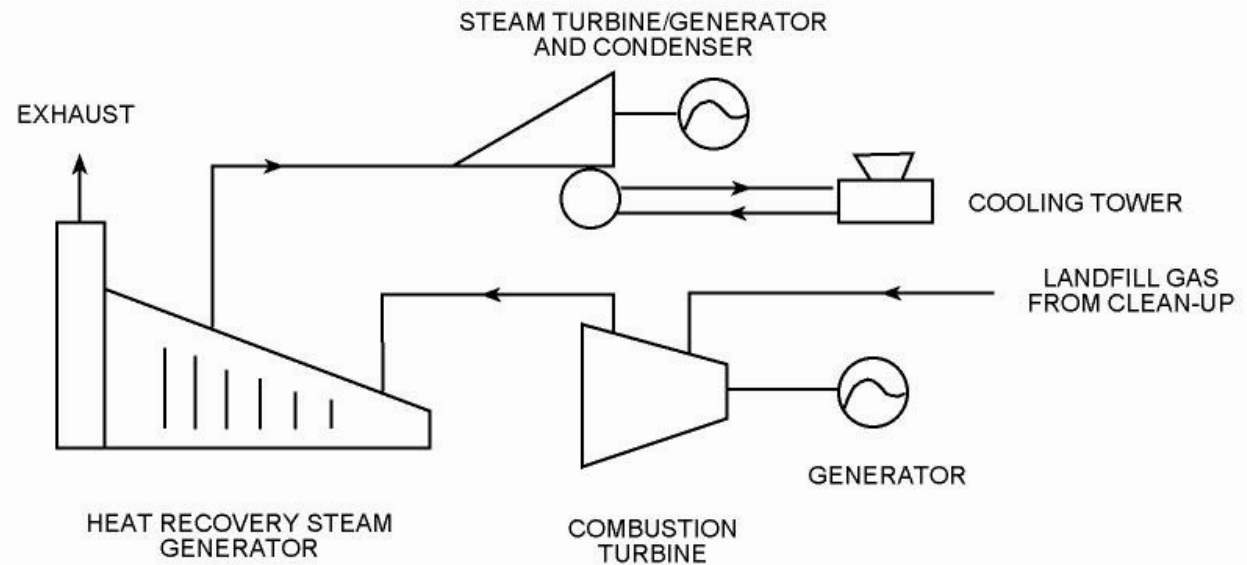


FIGURE 8
LANDFILL GAS CLEAN-UP PROCESS FOR COMBUSTION TURBINE POWER GENERATION

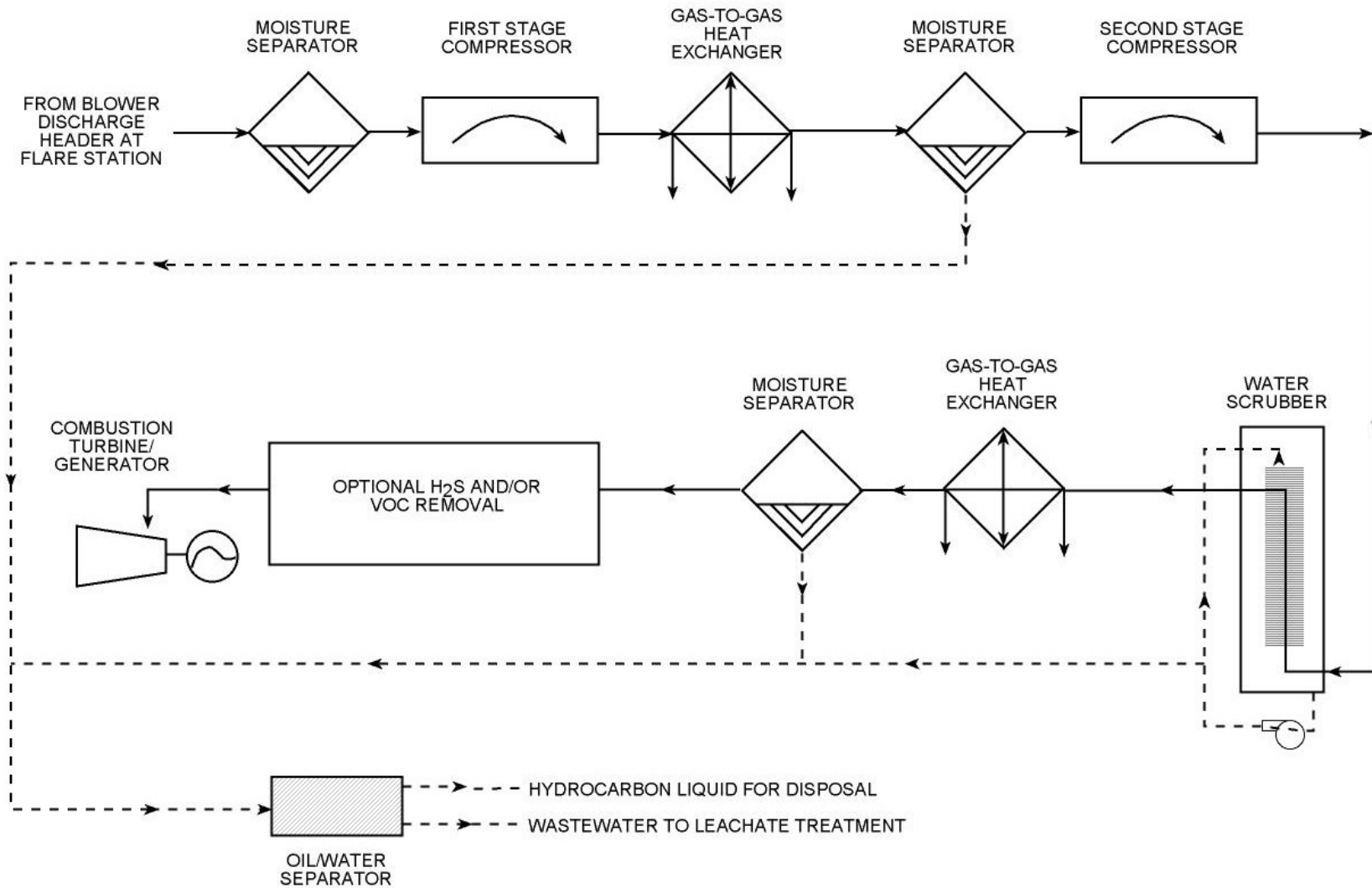


FIGURE 9
POWER GENERATION WITH STEAM CYCLE

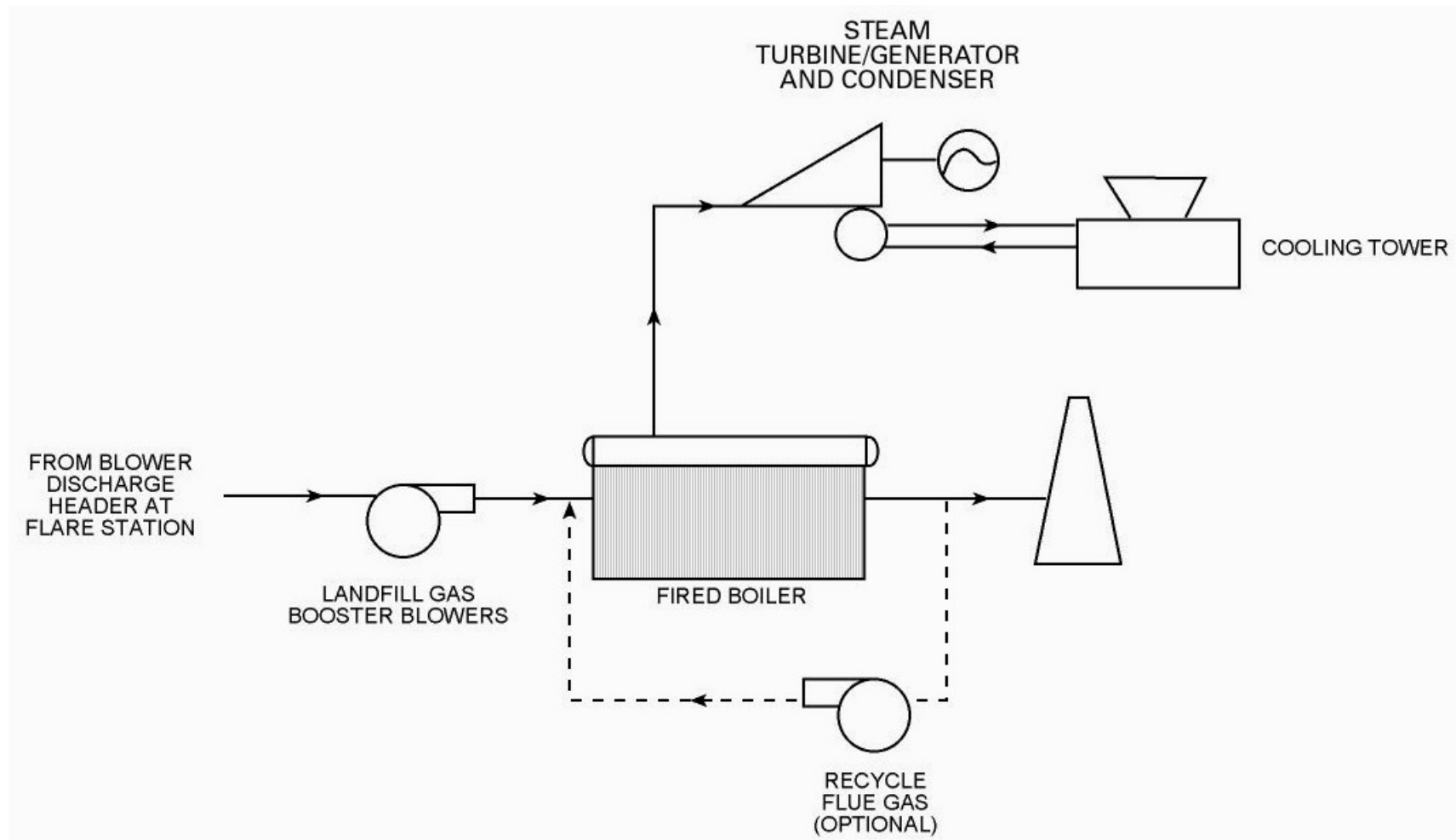
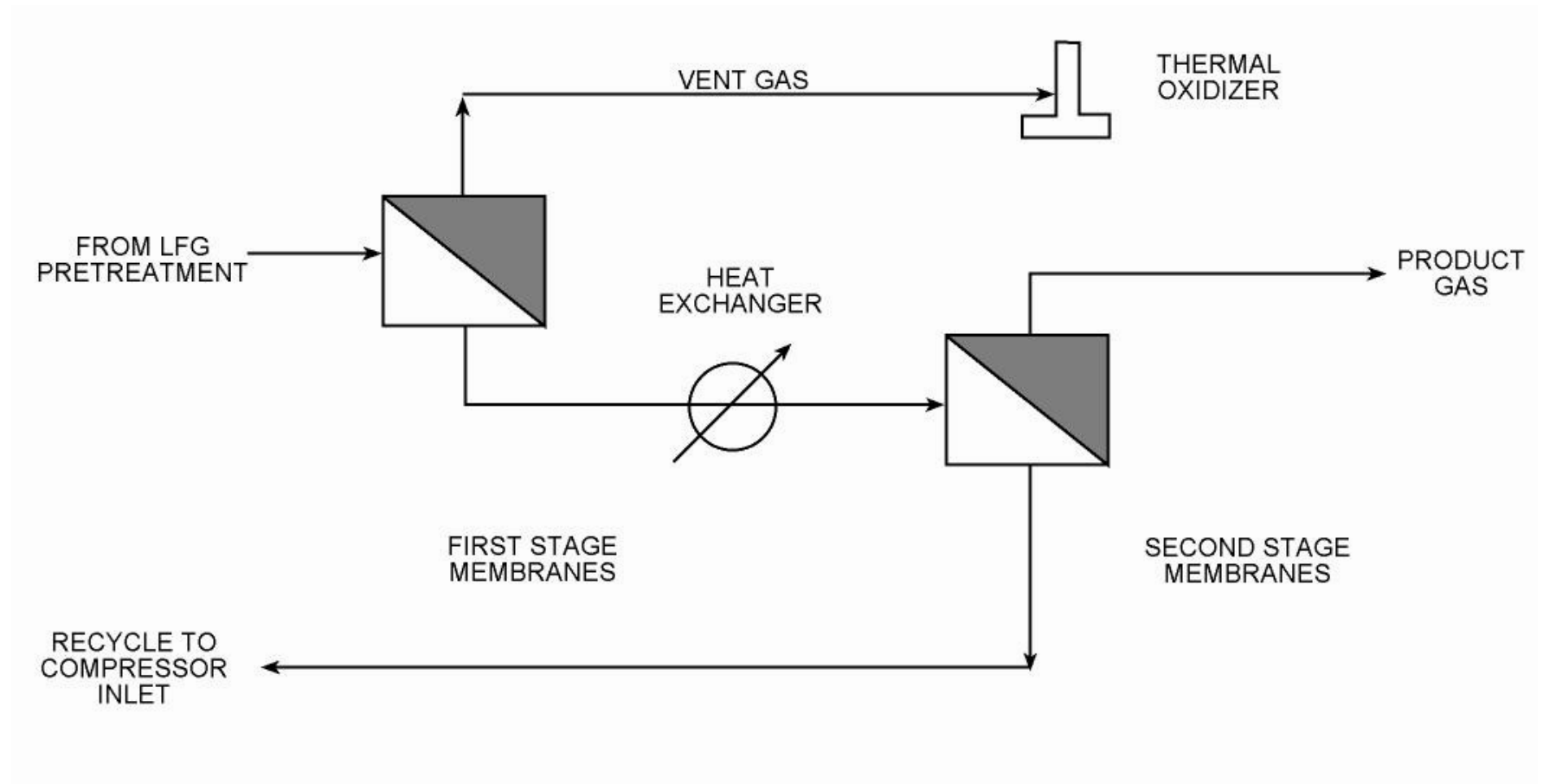


FIGURE 10
HIGH-BTU GAS BY MEMBRANE PROCESS



LANDFILL GAS CLEAN-UP PROCESS FOR HIGH-BTU GAS

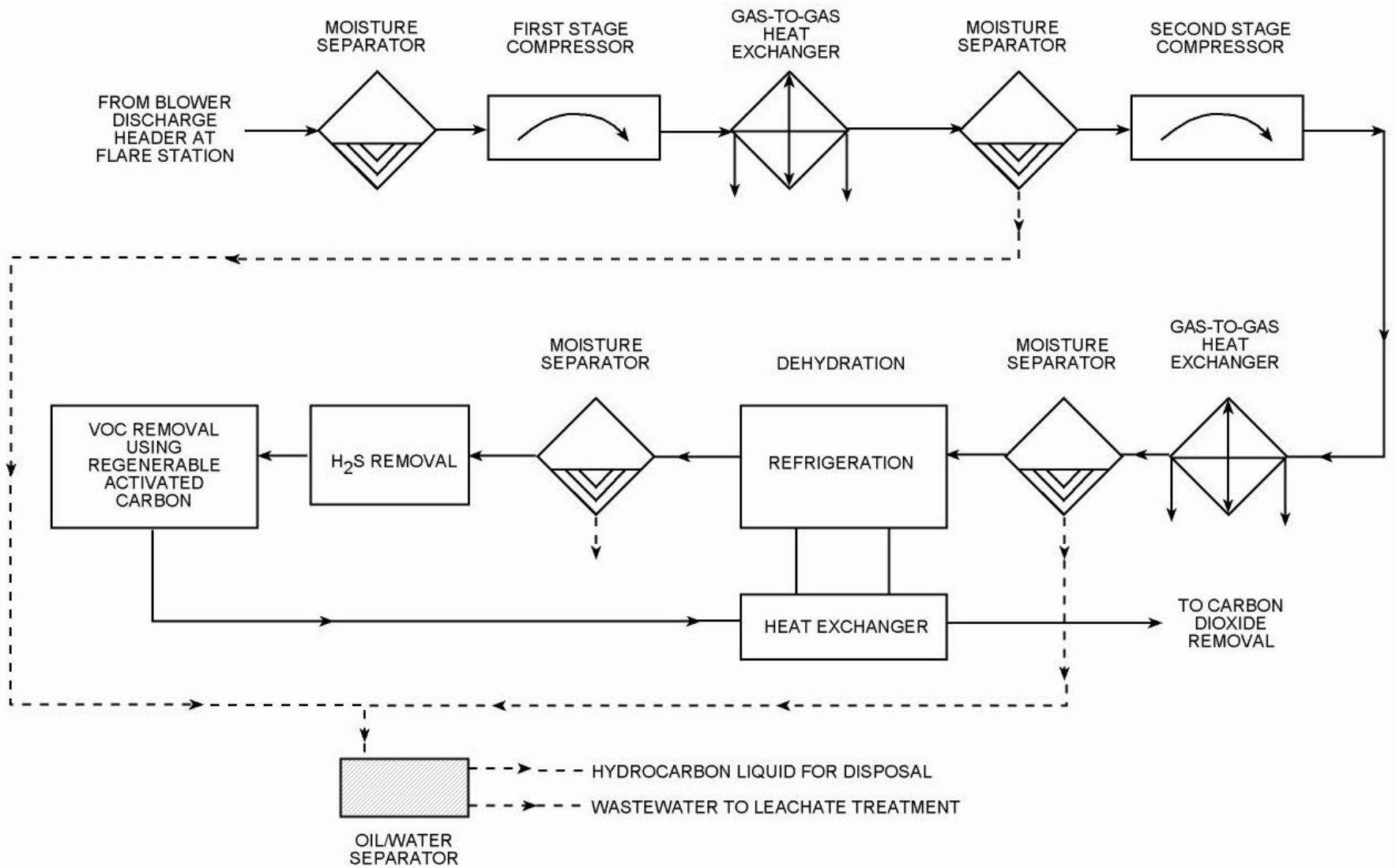


FIGURE 12
HIGH-BTU GAS BY MOLECULAR SIEVE

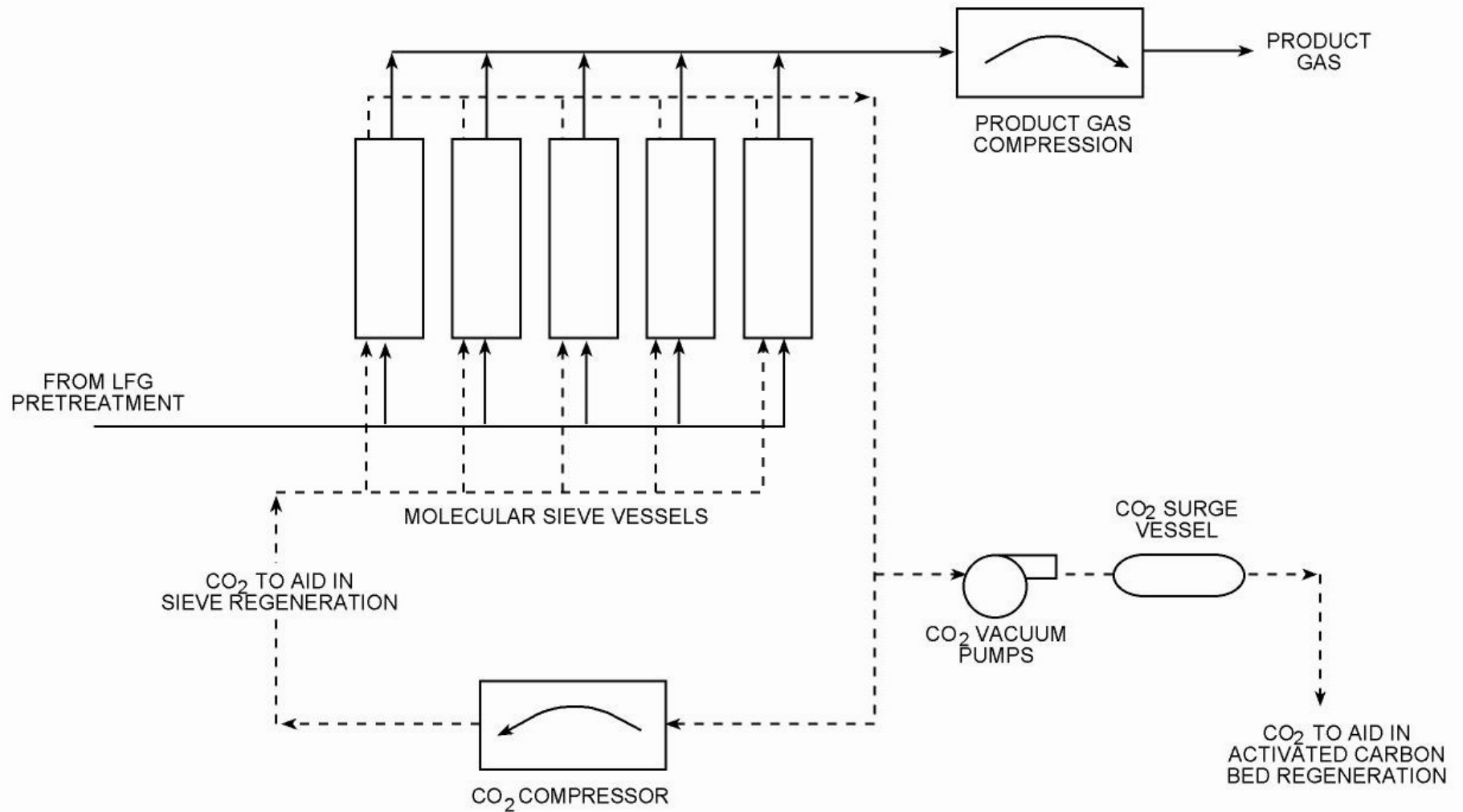


FIGURE 13
DEVELOPMENTAL RISK AS A FUNCTION OF TIME AND MONEY

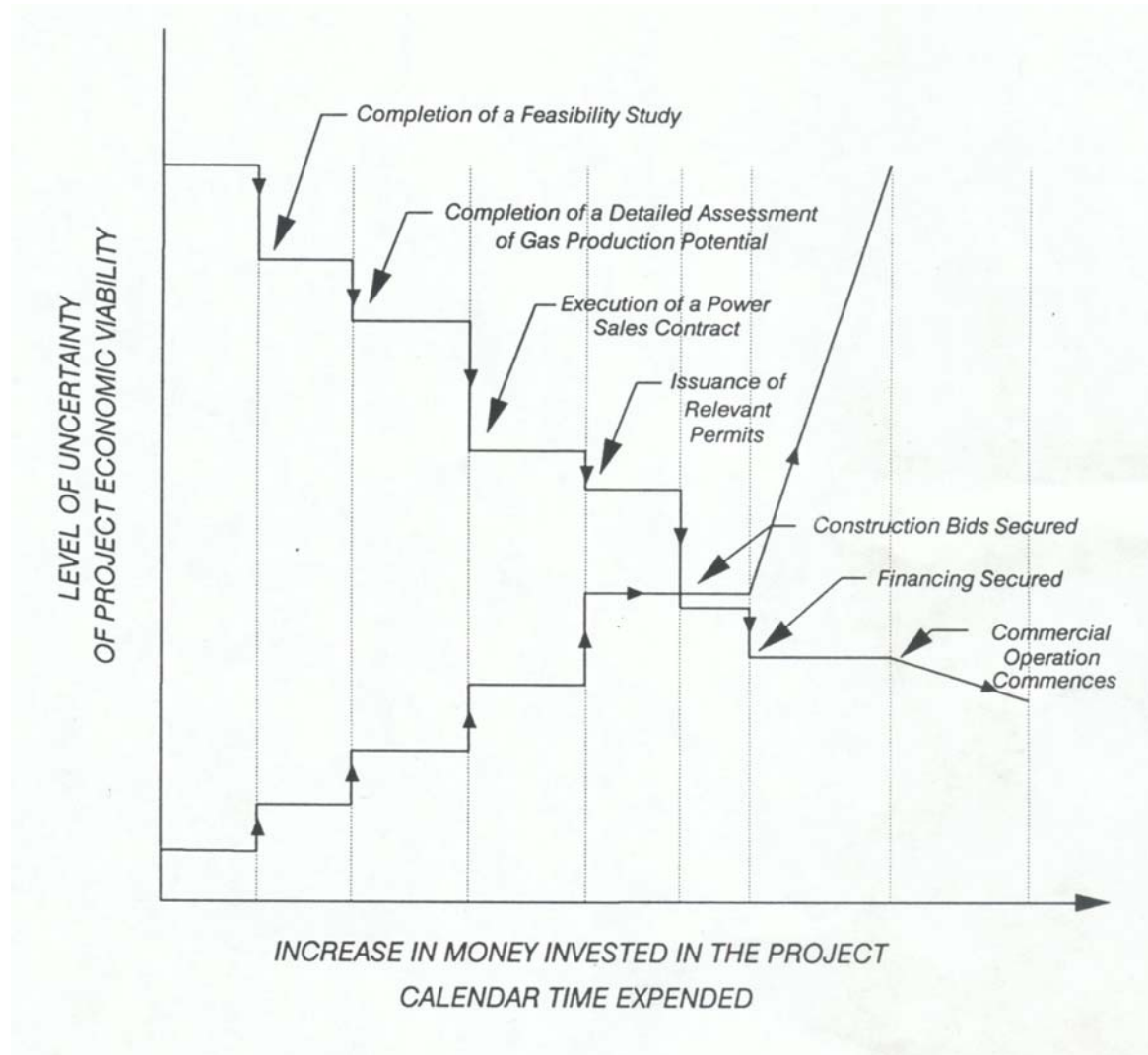


FIGURE 14
ALTERNATIVE STRUCTURES FOR IMPLEMENTING LANDFILL GAS POWER PROJECTS

