Landfill Gas Energy Technologies

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A Word from the Authors

This handbook has been developed during the project work carried out at the Oil and Gas Institute in Kraków (*Instytut Nafty i Gazu*) as part of the international Methane to Markets (M2) Partnership, initiated by the USA and presently including 33 countries. The primary objective of the Partnership is to reduce global methane emissions through implementation of economically feasible methods of methane collection in various areas of business activity and its beneficial use as a source of energy.

This handbook intends to address, in a comprehensive manner, the practical methods of using the energy contained in landfill gas. The authors' intension is to present landfill gas utilization methods, starting from heat production to technology-based on combined heat and power generation. Characteristic of each technology is presented in an accessible way and supported by examples of installation in operation. An important part of publication is to determining a project's possible development options of the investments and to provide elements of economic analysis, allowing to make a proper decision of landfill gas energy technologies.

This paper was developed on the basis of, *inter alia*, *LFG Energy Project Development Handbook* of the US Environmental Protection Agency.

Key Terms

CHP – Combined Heat and Power – wytwarzanie energii elektrycznej i ciepła w skojarzeniu
CNG – Compressed Natural Gas – sprężony gaz ziemny
PSA – Pressure Swing Adsorption – adsorpcja zmienno-ciśnieniowa
LFG – landfill gas – gaz składowiskowy
ppm – parts per million – części na milion
ppb – parts per billion – części na miliard
ppbv – parts per billion (volume) – części na miliard w danej objętości
IRR – Internal Rate of Return – wewnętrzna stopa zwrotu
NPV – Net Present Value – wartość zaktualizowana netto
CF – Cash Flow (USD or PLN) – przepływy pieniężne (w USD lub PLN)
J_0 – installed capital cost (USD or PLN) – wielkość nakładów inwestycyjnych (w USD lub PLN)
TDC – top dead centre – górny martwy punkt
DMP – bottom dead centre – dolny martwy punkt
LES – Leachate Evaporation System – system odparowania odcieków
RIC – Reciprocating Internal Combustion – określenie silnika: tłokowy silnik spalinowy
VOC – Volatile Organic Compound – lotne związki organiczne

1. Landfill Gas

A landfill site containing municipal waste works like a bio-reactor in which landfill gas (a gas mixture, composed primarily of methane, carbon dioxide and nitrogen) is produced in biochemical processes from the decomposition of organic matter. The composition of LFG produced by organic matter deposit in a municipal landfill varies significantly, both during the operation phase (acceptance of waste by the landfill) and after landfill closure. The intensity of gas production varies too, depending on the time elapsed since the deposition of waste in the landfill. The composition of LFG and its flow are key factors determining the correct and beneficial use of the energy potential of a landfill [1].

LFG qualifies as a source of renewable energy under Polish law. This creates an opportunity to obtain financial assistance for LFG energy projects, both during the construction phase and plant operation.

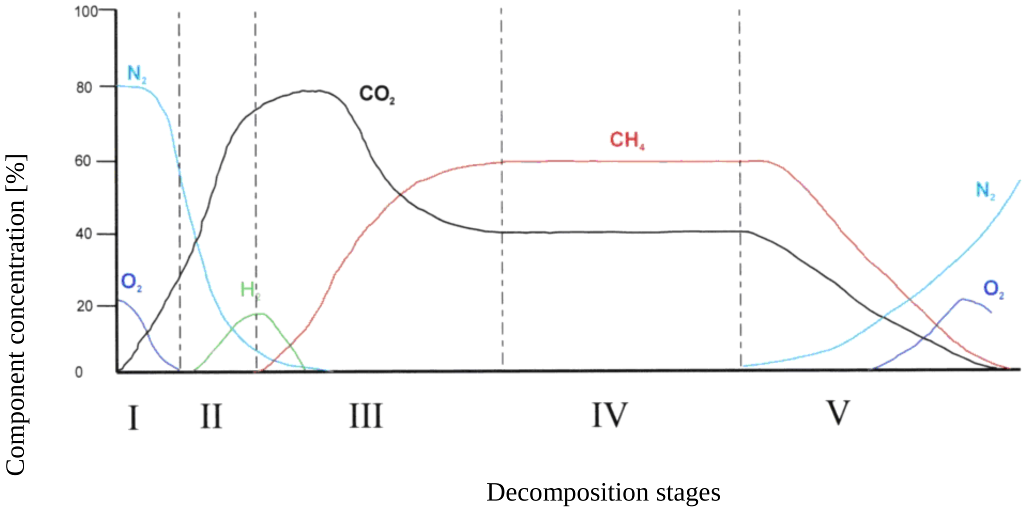
1.1 Characteristic Features of Landfill Gas

Biomass is the key substance for biochemical processes occurring in a municipal landfill producing biogas. Biomass includes only organic which has been minimally processed by humans and has not been utilized. Biomass differs from other organic substances in that biomass it is created naturally with the help of solar energy, or has been processed only by other living organisms. Therefore, in principle, products originating from chemical syntheses in industrial processes, requiring a large amount of energy to decompose into simple compounds, do not qualify as biomass [2]. Nevertheless, over a longer time frame, organic compounds produced by industrial activity of humans do decompose and can contribute to LFG generation from municipal solid waste.

The final product of biochemical transformations of organic substances contents carbon, oxygen and hydrogen under anaerobic conditions (in the presence of methane-excreting bacteria), is methane as well as a number of other products which are not further degradable.

A diagram depicting organic decomposition shows the varying components of landfill gas. The basic diagrams distinguishes between five stages of organic substance decomposition, including aerobic decomposition, anaerobic decomposition (acidic fermentation, unsteady and steady methanogenesis), and the end of LFG generation (equivalent to the end of methanogenesis). The diagram depicts the final, fifth stage of organic decomposition as the end of anaerobic decomposition and gradual fading of methane generation by landfilled waste.

Figure 1 shows a typical organic decomposition model, distinguishing five key stages of chemical and biochemical processes leading to landfill gas generation.



Stage 1: oxygen decomposition — *Duration: 7 – 30 days*
Stage 2: acidic fermentation — *Duration: 1 – 6 months*
Stage 3: unsteady methanogenesis — *Duration: 3 – 36 months*
Stage 4: steady methanogenesis. — *Duration: 5 – 50 years*
Stage 5: end of decomposition — *Duration: 10 – 40 years.*

Figure 1. Organic decomposition phases.
Source: [3]

Landfill gas generation have been relatively well researched. However, the gas generation process is affected by so many factors that, given the significantly variable site conditions, any theoretical assessment of the gas generation rate is overly complicated.

Empirical models were developed as a result at the need to accurately assess/estimate the volume of methane emissions. Some of the models may be conveniently applied to calculation of the energy potential of a LFG energy project. However, one should remember that any such estimates are prepared using mathematical models, and that modeling requires a wealth of data waste of landfill characteristics, such as waste composition, compaction, age, temperature, moisture content, type of cover, and landfill closure design etc. Calculations are made using various kinetic models of organic decomposition, while algorithms, due to difficulties with obtaining the necessary data, contain a large number of simplifying assumptions [1].

***US EPA** Model [4]*

The accuracy of calculations made using this model depends on the quality of data regarding the quantity and composition of waste accepted by a landfill and the manner in which it was deposited [5].

The volume of methane produced during one year Q_T is a sum of a methane volume Q_{Tx} produced in the year T from waste mass M_x, accepted in subsequent years x prior to the year T:

$$Q_T = \sum Q_{T,x}$$

The volume of methane produced in T year from waste mass M_x deposited in year x is calculated using the following equation:

$$Q_{T,x} = k \cdot M_x \cdot L_o \cdot e^{-k(T-x)} [m^3 CH_4]$$

where:

x - year of waste deposition,

T - year of emission calculation,

k - methane generation rate; it is assumed that k is a function of solid waste moisture, nutrients supply for methanogenic bacteria, pH and temperature. It value remains within the range from 0,003 to 0,21 year^{-1}

L_o - potential methane generation capacity, i.e. methane volume [m^3] generated per solid waste mass unit [6].

The US-EPA model includes specific values of the methane generation rate constant and potential methane generation capacity (two sets of data called CAA and AP 42). The CAA data (see *Clean Air Act*) based on the requirements of the *New Source Performance Standards* (NSPS). The AP-42 (U.S. EPA manual) use emissions coefficients that are more representative of typical municipal solid waste landfill. The values of the parameters are presented in Table 1.

Table 1. Set of data acc. to CA and AP42

Parameters	L_o [m^3/t]	k [1/year]	Methane concentration [%]
CAA	170	0.05	50
AP 42	100	0.04	50

Source: [5].

The application of the coefficients of organic decomposition, the US-EPA model describes very well the actual decomposition conditions in the municipal landfill. A wide range of values of the potential methane generation capacity (L_0) seems to be a drawback of the method as well as lack of information on the structure and characteristic of a municipal solid waste landfill. Wrongly assumed values may increase or decrease the final results.

IGNIG Model *[4]*

In the IGNIG model the kinetic method used in the US EPA model has been greatly expanded. It is based on the first order kinetic model and considers 4 categories of solid wastes. Each category of organic wastes has its own half-life time $t_{1/2}$, designated to it. The following half-life's are available:

Waste category:	Half-life:
A – paper, textiles	tauA = 10 years
B – garden, park wastes, and others (except food)	tauB = 6 years
C – food	tauC = 3 years
D – wood and feed (except lignins)	tauD = 15 years

The annual volume of methane produced (*$EmCH_4$*) is a sum of a methane volume $EmCH_{4r,x(i)}$ produced in a given year from a waste mass MASA [Mg] deposited in the following years, x, prior the calculation year:

$$EmCH_4 = \sum EmCH_{4_{T,x}}(A) + \sum EmCH_{4_{T,x}}(B) + \sum EmCH_{4_{T,x}}(C) + \sum EmCH_{4_{T,x}}(D)$$

Decomposition of wastes from (i) category, deposited in year x, between year x and T, where T is the calculation year is calculated from the equation:

$$MC_{T,x} = MSW \cdot MCF \cdot MASA \cdot udz(i) \cdot (1 - e^{-\lambda(i)(T-x)})[tons]$$

where:

i - waste index (A ... D).

udz(i) - mass of wastes of a category as a fraction of the total mass of wastes deposited annually

MASA - total mass of solid wastes deposited in year [Mg].

λ (i) - value depending on a half-life time for each solid waste category, calculated from the equation: λ(i) = 0.693148 / tau(i).

x - year of solid waste deposition.

T - calculation year.

MSW - fraction of solid wastes deposited at the landfills.

MCF - correction factor for methane.

Solid waste mass at (i), category, which decomposed in year T is calculated from the formula:

$$MR_{T,x(i)} = MC_{T,x(i)} - MC_{T-1,x(i)}[tons]$$

Methane volume produced in the calculation year from the solid wastes of (i) category, included in the mass MASA deposited in year x, is calculated from the formula:

$$EmCH_{4_{T,x}}(i) = DOC \cdot F \cdot conv(i) \cdot MR_{T(i)}[m^3CH_4]$$

where:

DOC - organic content in solid wastes,

F - molar fraction of methane in landfill gas (mol/mol),

conv(i) - decomposition of organic material in the following wastes categories [4].

The IGNIG model was developed by the Oil and Gas Institute.

LFG generation rate may be assessed using the equations shown above, for each year starting from the first year in which waste is deposited in the landfill. Figure 2 shows an example of a gas generation curve.

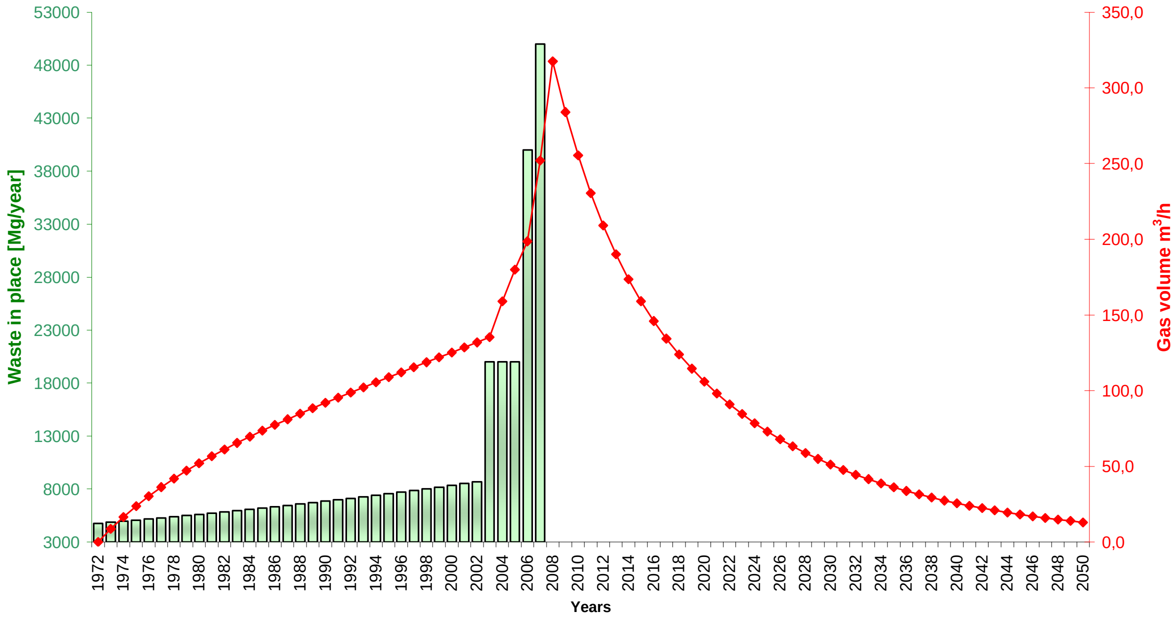


Figure 2. Landfill gas modelling
Source: INIG figure.

1.2 Collection of Landfill Gas

A gas extraction system from a municipal solid waste landfill consists of the following elements:

- Gas vents from the landfill bed (vertical wells and horizontal pipes)
- Header pipes discharging gas to the collection point (collection station)
- Collection station (demoisturisers, blowers, measuring/performance monitoring equipment)

1.2.1 Elements of installation for gas extraction

Vertical gas extraction system - wells

Newly constructed municipal solid waste landfills may have their extraction wells built on the layer of soil planted directly on a geomembrane, which serves as an additional landfill lining (Picture 1). This way the stress of the well on a geomembrane is reduced and the landfill lining is not damaged. Solid wastes are deposited and compacted around wells, which are spaced every 30 – 50 m. At the lower part of the well a filter is mounted. A horizontal header pipe running from the filter discharges leachate to the collection well. A gas extraction well filter consists of a slotted 100 - 200 mm diameter pipe. Pipe length is 2 m and it can be further extended once the landfill is full. The well is protected by a 1m diameter steel pipe; pipe length 2.5 – 5.0 m). A space between the filter and well cover is filled with gravel and cover with a sealing ring. The well cover is gradually extended and the extra space made up with gravel once the landfill expands. The upper part of the filter is made from a non-perforated pipe. A header equipped with a gas valve is mounted on the non-perforated pipe. An outlet port of the valve is connected with a compensation hose to the installation of active gas extraction from the landfill.

Picture 1. Wells installed on new landfill sites.
Source: INiG photo.

Picture 2. Wells drilling on reclaimed landfill.
Source: http://www.kellettswell.com/drilling.html

On existing landfills, the gas extraction wells are driven into the ground using boring tools (Picture 2). Bore-holes of 400 – 460 mm diameter go down to the solid waste base. In bore-holes perforated pipes are installed; the space between pipe and a bore-hole is filled with gravel. An upper part of the bore-hole is sealed with clay, while space next to the bore–hole is covered with a geomembrane (Figure 3). Such insulation protects against infiltration of atmospheric air into the solid waste bed. Extracted LFG is transported to the collection station, which is an important part of the gas utilization system.

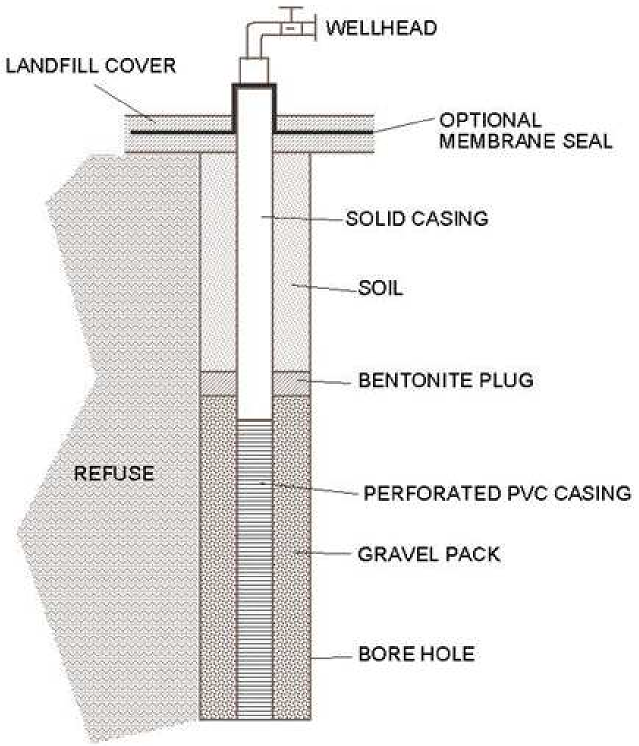


Figure 3. Vertical gas extraction wells.
Source: [7].

Horizontal gas extraction system – horizontal pipes

Another way of gas extraction from a municipal solid waste landfill is horizontal well system. The total landfill surface area is divided into cells approximately 1 ha each. In each sector, collection pipes are installed at a permeable layer of inert material (thickness app. 200 mm), within a waste bed. Pipes from each sector are arranged at a sufficient slope so as to remove condensate; pipes transport gas to the collection station. Such ventilation systems are preferred when gas migration beyond is a concern.

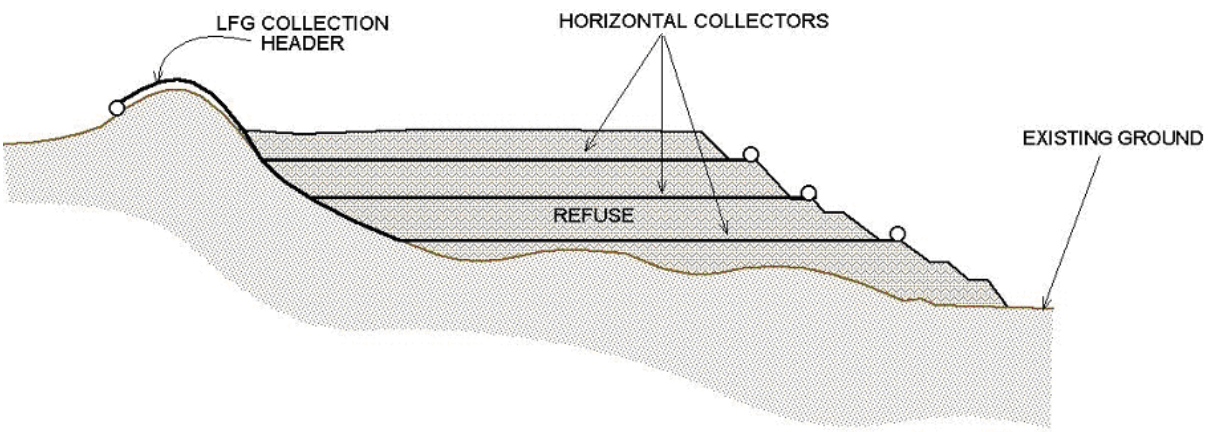


Figure 4. Horizontal gas extraction system
Source [7].

Vertical-horizontal collection system

Some landfills use installations consisting of both vertical gas wells and perforated horizontal pipes. Such collection method is often used at the landfills with a thick layer of solid waste. In such cases, horizontal pipes are connected with vertical wells at numerous levels to facilitate the gas discharge to the well. Such an option has the economic advantage of a reduced number of wells.

1.2.2 Connection of elements of a landfill gas extraction installation

Gas extraction wells and horizontal pipes can be connected in one of two ways.

Individual headers

Individual headers require that there is a single pipe running directly from each well (or a horizontal header) to the gas collection station. The basic advantage of a direct connection between gas extraction wells and the collection station is a possibility of regulation of all wells at single spot. The most popular are 50 - 63 mm pipes. The drawbacks of this solution include possible siphoning and some problems with gas flow. The operational problems appear mostly when pipes have not been placed properly.

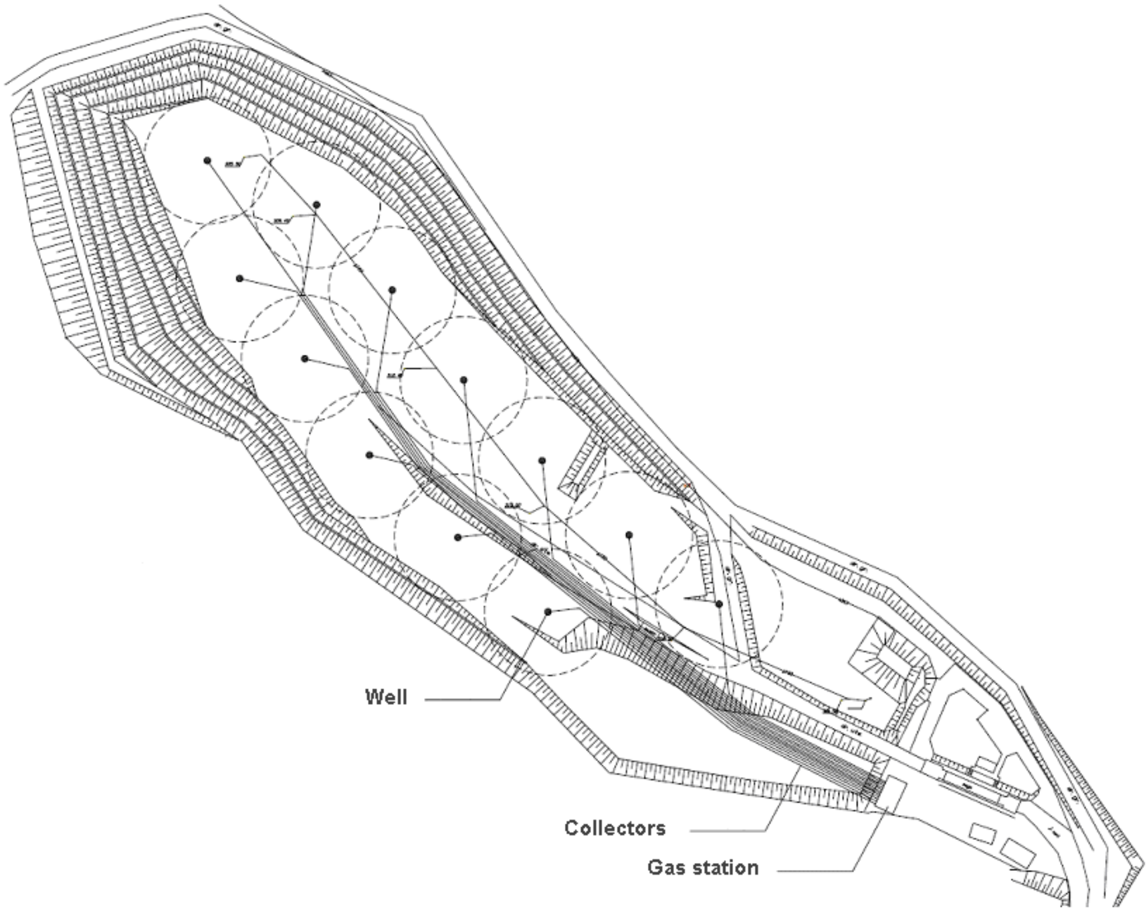


Figure 5. Example of individual collection system.
Source: INiG figure.

Collective headers

In collective headers, individual wells and horizontal headers are connected to the main headers, which supply gas to the collection station. Gas extraction wells are linked to several collective headers (called bulkheads) of 100 – 160 mm diameter, most frequently at the landfills with a large surface area. The main advantage of such construction is easy removal of condensate due to a better gas line capacity; there is no need for intermediate driplegs between the well and the collection station. On the other hand, regulation of gas extraction from the landfill becomes more troublesome, since the adjustment valves are installed at the heads of wells located all over the landfill area.

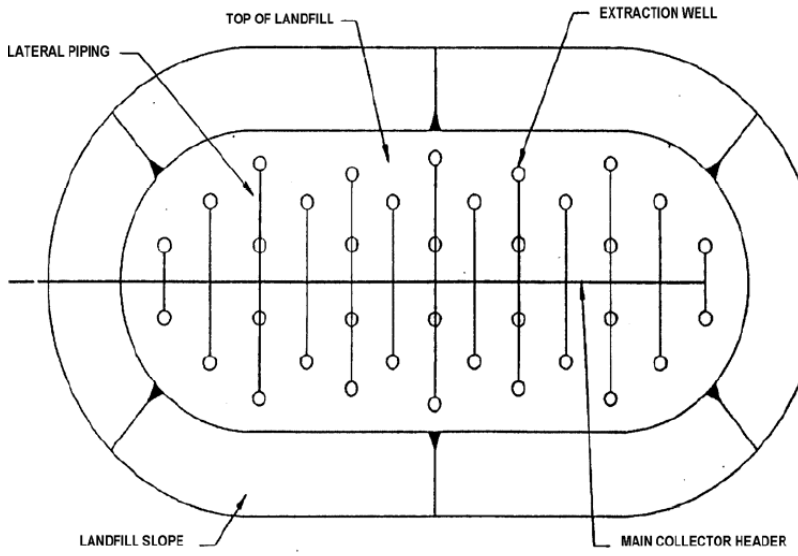


Figure 6. Example of collective headers.
Source: [7]

1.2.3 Gas Collection Station

The gas collection station is comprised to the following units:

- central collectors connected to pipelines to transmit gas off the landfill (Picture 3);
- Blowers to extract gas from the landfill (Picture 4 and 5);
- Filters to remove solids (Picture 4 and 5);
- Reservoirs where condensate is removed from the gas (Picture 4 and 5);
- Instruments for control of gas extraction and transport;
- Measuring & control equipment.

A diagram of a typical gas collection station is presented in Figure 7.

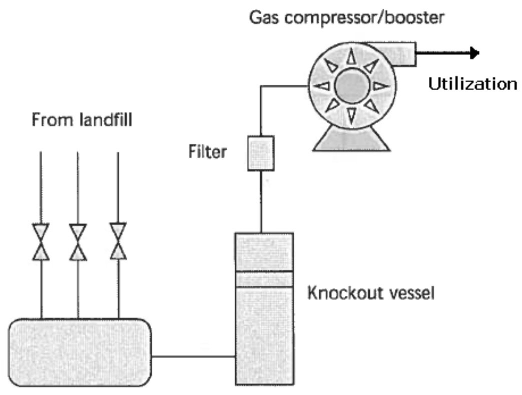


Figure 7. Gas collection station diagram.
Source: [8].

Picture 3. Landfill Gas Collection Station
Source: INiG photo.

Picture 4. Gas collection system on Prince William County landfill, USA.
Source: INiG photo.

Picture 5. Gas collection system on Oaks landfill, USA.
Source: INiG photo.

1.3 Landfill Gas Contaminants and Their Removal

Direct use of collected raw landfill gas is impaired by gas contaminants such as hydrogen sulphide, siloxanes, moisture etc.

Landfill gas needs to be treated due to its relatively high content of contaminants. The treatment should be comprised of the following stages:

Stage I

Primary treatment, consisting of the removal of solids and liquids, and gas drying.

Stage II

Advanced treatment:

- desulphurisation;
- removal of organic silicon compounds;
- removal of other gaseous contaminants, such as hydrocarbons and ammonia.

The type of gas treatment used is dependent on the technical and economic constraints.

1.3.1 Primary Treatment

Primary treatment technologies represent the first stage in reducing the amount of contaminants in the landfill gas and typically use simple physical process operations. The main contaminants removed (or reduced) are:

- water (referred to as 'condensate'),
- particulates.

The technology used to remove these contaminants have been in use for many years and are now a relatively standard element of active landfill gas management plants [8].

Water/condensate knockout

The presence of liquid water in landfill gas pipework can have a detrimental effect on plant performance. First, the accumulation of water reduces the space available for gas flow and raises the pressure loss. Secondly, the unstable nature of two-phase flow (i.e. liquid and gas combined) can give rise to oscillations, which in turn, make it difficult to achieve a steady and controllable operation. The presence of contaminated water can also lead to deposits on the pipe walls, which reduce the smoothness and further increase the pressure loss. The presence of liquid water in landfill gas pipes should thus be both controlled and minimized. Depending on the source of the gas and the application or proposed use of the treated landfill gas, three components can be treated. These are:

- slugs of liquid
- gas-liquid foam
- uncondensed water vapour [8].

Liquid water capture

In-line de-watering is frequently adopted by landfill operators and is usually installed within the landfill gas collection network. However, there is invariably a need to incorporate additional control measures to prevent onward transmission of liquid water. In some cases, drains and water traps may be adequate for a particular supply gas specification. A further common practice – usually forming the final element of de-watering – is a knockout drum. This is often called a 'condensate knockout pot' – and occasionally a 'slug catcher' – and is located as close as practicable to the inlet to the gas booster. The purpose of the knockout drum is to lower the gas velocity sufficiently for 'dropout' of liquid, which can then be drained or pumped to discharge. Such devices are simple and capable of handling large gas flows (up to 10 000 m^3/hour) and of removing > 1 litre/minute of water [8].

Foam removal

One refinement of water control systems is the incorporation of coalescing (or demisting) meshes in the gas pipes entering and leaving a condensate knockout drum. These meshes collapse entrained foam and prevent carryover. Typically, the meshes are woven stainless steel pads which provide a large surface area to trap the foam and allow it to drain under gravity to the collection drum [8].

Vapour reduction

Raising the pressure of a gas mixture leads to an increase in temperature. While some of the heat of compression will be dissipated at source, the temperature of the delivery gas stream will inevitably be significantly higher than ambient. This may make it necessary to cool the gas to protect control valve seats, to prevent over-stressing of polyethylene (PE) pipework and to meet other criteria for reliable metering or consumer safety considerations.

For applications where gas conditioning is specified (e.g. to reduce the amount of water vapour and lower the dew point), a pre-chilling step may be required to avoid an excessive thermal load on the conditioning unit. Pre-chilling and after-cooling are carried out for different reasons, but both involve heat removal from the high-pressure delivery gas stream. The amount of heat to be removed will depend on:

- the specific heat capacity of the gas mixture;
- the booster exit temperature;
- the mass flow rate of gas;
- the specified final temperature.

For typical primary clean-up processes (e.g. those using a centrifugal gas booster), the heat load is unlikely to require specialist equipment and a length of 5 – 10 meters of corrosion-protected steel pipework may be sufficient. However, a forced draught cooling stage may be helpful in some cases, e.g. space is restricted. During after-cooling, compression will reduce the relative humidity. This will depend on the specific moisture content of the gas stream leaving the landfill and will be reversed on cooling. The reduction in relative humidity can lead to condensation in the delivery line, causing problems for the consumer. It is therefore essential to review and measure the temperature profile along the pipework and, if necessary, install insulation, lagging or trace heating on the downstream end of the pipe [8].

1.3.2 Advanced Treatment

Typically, landfill gas used in a utilization plant receives only primary treatment. However, there is a range of processes that are designed to provide much greater gas cleaning than is possible using just primary systems. Such processes, which include both physical and chemical treatments, can be defined collectively as secondary treatment [8].

Hydrogen sulphide removal

Hydrogen sulphide is an extremely toxic and flammable gas, harmful to the environment. Under temperature, hydrogen sulphide reacts with steam to produce sulphuric acid, which has a significant effect on the useful life of a LFG plant. Landfill gas may be desulphurised using various processes. Depending on the choice of the agent, one may distinguish biological, chemical and physical desulphurisation processes.

The choice of one of the many available technologies depends on the gas composition, the extent to which it needs to be treated and the mass flow rate of the treated gas. A comparison of the economics of various methods of landfill gas desulphurisation is shown in Table 2.

Table 2. A comparison of various techniques of H_2S removal.

Method	Throughput rate	Capital expenditure	Operating costs
Biological desulphurisation	Medium	Medium	Low
Treatment with iron chloride	Medium	Low	Medium
Water washing	High	High	Medium
Activated carbon	High	High	Medium
Iron oxide or hydroxide	High	Medium	Medium
Sodium hydroxide	High	Medium	High

Source: [19].

Siloxane removal

Siloxanes are a family of man-made organic compounds that contain silicon, oxygen and methyl groups. Siloxanes are used in the manufacture of personal hygiene, health care and industrial products. As a consequence of their widespread use, siloxanes are found in solid waste deposited in landfills. At landfills, low molecular weight siloxanes volatilize into landfill gas. When this gas is combusted to generate power (such as in gas turbines, boilers or internal combustion engines), siloxanes are converted to silicon dioxide (SiO_2), which can deposit in the combustion and/or exhaust stages of the equipment. Evidence of siloxanes in landfill gas is found in the form of a white powder in heated gas turbine components, as a light coating on various types of heat exchangers, in deposits on combustion surfaces in reciprocating engines, and as a light coating on post-combustion catalysts [9].

The key methods used for siloxane removal are:

- adsorption on activated coal;
- adsorption in a liquid hydrocarbon mixture,
- gas cooling with concurrent water knockout. A gas may be cooled down as much as to – 70˚C, resulting in 99% siloxane reduction.

Other landfill gas contaminants

A landfill gas may also contain the following other contaminants:

- ammonia;
- aromatic hydrocarbons, i.e. benzene, toluene, ethylobenzene, xylene;
- halogens.

These contaminants are usually present in landfill gas at concentrations below the detection level. The concentration of ammonia is below 0.1 mg/m^3, that of aromatic hydrocarbons – below 1 mg/m^3 and that of halogens – below 0.1 mg/m^3, facilitating immediate use of gas without the need for any additional treatment systems.

2. Landfill Gas Energy Technologies

There are several ways to effectively utilize landfill gas for energy; however, the primary application in Poland is electricity. Electricity for onsite use or sale to the grid can be generated using a variety of different technologies, including:

- internal combustion engines,
- gas turbines,
- microturbines,
- Sterling engines (external combustion engine).

The vast majority of projects use internal combustion (reciprocating) engines or turbines, with microturbine technology being used at smaller landfills and in niche applications [10]. Certain technologies such as the Sterling and Organic Rankine Cycle engines and fuel cells are still in the development phase.

LFG energy CHP applications, also known as cogeneration projects, provide greater overall energy efficiency and are growing in number. In addition to producing electricity, these projects recover and beneficially use the heat from the unit combusting the LFG. LFG energy CHP projects can use internal combustion engine, gas turbine, or microturbine technologies.

Less common LFG electricity generation technologies include a few boiler/steam turbine applications, in which LFG is combusted in a large boiler to generate steam used by the turbine to create electricity. A few combined cycle applications have been implemented in USA. These combine a gas turbine that combusts the LFG with a steam turbine that uses steam generated from the gas turbine's exhaust to create electricity. Boiler/steam turbine and combined cycle applications tend to be larger in scale than the majority of LFG electricity projects that use internal combustion engines [7].

Another application of landfill gas is production of hot water or steam. However, such use of landfill gas is to a large extent dependent on hot water or steam demand in the close proximity to the landfill. Transmission of gas or small quantities of steam or hot water over a long distance makes the undertaking much more complex in terms of technical aspects, and in many cases is not viable.

In situations with low gas extraction rates, the gas can go to power infrared heaters in buildings local to the landfill or provide heat and power to local greenhouses, and power the energy intensive activities of a studio engaged in pottery, metalworking or glass-blowing.

Heat is fairly inexpensive to employ with the use of a boiler. A microturbine would be needed to provide power in low gas extraction rate situations [7].

Another factor which plays an important role in landfill gas application is gas treatment, described in Section 1.3.

Figure 8 presents an overview of LFG energy projects for which technologies are readily available.

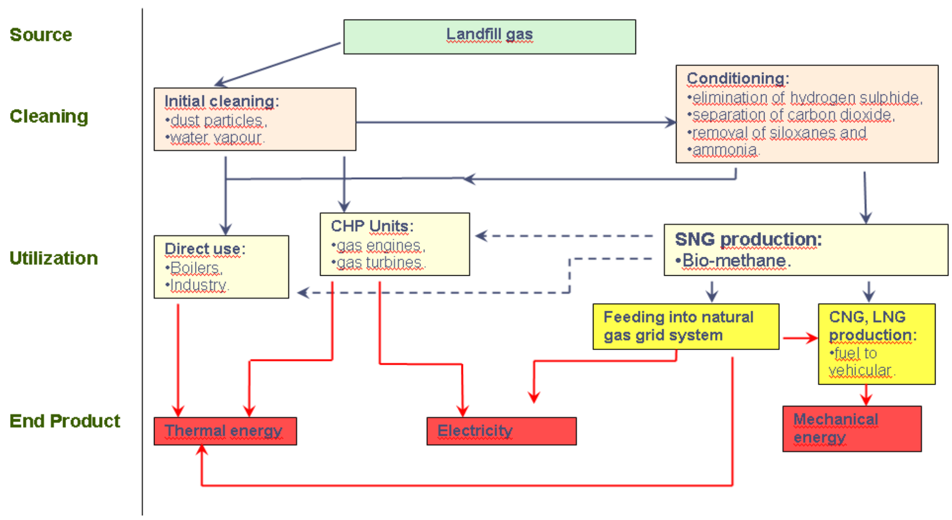


Figure 8. Methods of beneficial utilisation of landfill gas.
Source: INiG

2.1 Direct Use

Directly using LFG to offset the use of another fuel (natural gas, coal, fuel oil) is occurring in about one-third of the currently operational projects in USA. This direct use of LFG can be in a boiler, dryer, kiln, or other thermal applications. It can also be used directly to evaporate leachate. Innovative direct uses include firing pottery and glass blowing kilns; powering and heating greenhouses and an ice rink; and heating water for an aquaculture operation. Current industries using LFG include auto manufacturing, chemical production, food processing, pharmaceutical, cement and brick manufacturing, wastewater treatment, consumer electronics and products, paper and steel production, and prisons and hospitals, just to name a few [10].

Direct use of LFG is often a cost-effective option when a facility that could use LFG as a fuel in its combustion or heating equipment is located within approximately 8 km of a landfill; however distances of 16 km or more can also be economically feasible in some situations. In

USA some manufacturing plants have chosen to locate near a landfill for the express purpose of using LFG as a renewable fuel that is cost-effective when compared to natural gas.
The number and diversity of direct-use LFG applications is continuing to grow. Project types include:

- Boilers, which are the most common type of direct use and can often be easily converted to use LFG alone or in combination with fossil fuels.
- Direct thermal applications, which include kilns (e.g., cement, pottery, brick), sludge dryers, infrared heaters, paint shop oven burners, tunnel furnaces, process heaters, and blacksmithing forges, to name a few.
- Leachate evaporation, in which a combustion device that uses LFG is used to evaporate leachate (the liquid that percolates through a landfill). Leachate evaporation can reduce the cost of treating and disposing of leachate.

2.1.1 Process Heat Generation

The simplest and often most cost-effective use of LFG is as a fuel for boiler or industrial process use (e.g., drying operations, kiln operations, and cement and asphalt production). In these projects, the gas is piped directly to a nearby customer where it is used in new or existing combustion equipment (Picture 6 and 7) as a replacement or supplementary fuel. Only limited condensate removal and filtration treatment is required, but some modifications of existing combustion equipment might be necessary.

Picture 6. Boiler fuelled by landfill gas.
Source: [7].

Picture 7. Cement Kiln.
Source: [7].

The energy requirements of a patented LFG consumer are an important consideration when evaluating the sale of LFG for direct use. Because no economical way to store LFG exists, all gas that is recovered must be used as available, or it is essentially lost, along with associated revenue opportunities. The ideal gas customer, therefore, will have a steady annual gas demand compatible with the landfill’s gas flow. When a landfill does not have adequate gas flow to support the entire needs of a facility, LFG can still be used to supply a portion of the needs. For example, in some facilities, only one piece of equipment (e.g., a main boiler) or set of burners is dedicated to burning LFG. These facilities might also have equipment that can use LFG along with other fuels. Other facilities blend LFG with other fuels [7].

LFG is classified as a “medium Heating Value gas” with a heating value of about 18,3 MJ/m^3, about half that of natural gas. Therefore, the volume of LFG that must be handled by the fuel train and burner is twice that of natural gas. This means that modifications to the fuel train and burner are usually required to accommodate the higher overall gas flow rate for an equivalent natural gas heating value. The increased gas flow, however, does not have an appreciable effect on the design and operation of boiler components downstream of the burner [11].

The equipment for retrofitting a boiler to burn LFG is commercially available, proven, and not overly complex. The decisions that must be made during engineering and design are, however, site-specific and may be somewhat involved. For example, some installations have retained the original burner but modified it for LFG (e.g., by installing separate LFG fuel train and gas spuds) while maintaining the existing natural gas fuel train and gas ring to permit LFG/natural gas co-firing. Other installations have replaced the entire burner, controls, and fuel train with a dual-fuel burner and dual-fuel trains specifically designed to handle medium Heating Value gas. In general, the decision to furnish all new equipment is made based on the owner's preference or because the existing burner and controls are nearing the end of their useful lives. Additional analysis may be required to determine the amount of LFG compression that is provided versus the modifications needed for the burner and gas train.
Because LFG is typically a wet gas often containing trace corrosive compounds, the fuel train and possibly some burner "internals" should be replaced with corrosion-resistant materials. Stainless steel has typically been the material selected.
The controls associated with fuel flow and combustion air flow need to be engineered to cope with the variable heat content of LFG. The complexity of the burner management system will depend upon whether the boiler is to be co-fired with natural gas or oil and whether the boiler is to be co-fired at all times or if there will be times when it will be fired with LFG only. Today's modern controls, fast-responding oxygen analyzers, and responsive flame sensors make it possible to fire LFG with the same level of safety that is characteristic of current natural gas systems [11].

A potential problem for boilers is the accumulation of siloxanes. The presence of siloxanes in the LFG causes a white substance (similar to talcum powder) to build up on the boiler tubes. Where the material collects and how much of it accumulates is likely to be a function of the velocity patterns in the boiler and the siloxane concentrations in the LFG. Operators' experiences to date indicate that annual cleaning is sufficient to avoid operational problems related to silicon oxide accumulation. Boiler operators may also choose to install a gas treatment system to reduce the amount of siloxanes in the LFG prior to delivery to the boiler.

In designing and assessing the economic feasibility of projects utilizing LFG in boilers, several factors in addition to the boiler retrofit must be considered. For example, the quantity of LFG available must be considered and compared to the facility's steam needs and boiler capacities. Factors such as pipeline right-of-way issues and the distance between the landfill and the boiler will influence costs and the price at which LFG can be delivered and sold to the boiler owner. Because LFG is generally saturated with moisture, gas treatment is needed before the LFG is introduced into the pipeline and subsequently the boiler, to avoid condensation and corrosion. Additionally, condensate knock-outs along the pipeline are necessary as condensation in the main pipeline can cause blockages. Fortunately, the level of LFG clean-up required for boiler use is minimal, with only large particle and moisture removal needed. Other compounds in LFG, such as siloxanes, do not damage boilers or impair their function. Generally, LFG clean-up and compression systems are located at the landfill and are often installed by a developer rather than by the boiler owner. LFG compression provided at the landfill must be sufficient to compensate for pipeline pressure losses and provide sufficient pressure at the boiler to permit proper function of the fuel controls and burner. Proper attention to burner selection or burner modification for low-pressure operation can minimize the LFG compression costs [11].

Virtually any commercial or industrial boiler can be retrofitted to fire LFG, either alone or co-fired with natural gas or fuel oil. The firing profile is a primary consideration, regardless of the boiler type, since the fuel cost savings associated with LFG must offset the costs of the LFG recovery (if a LFG collection system is not yet in place), the gas clean-up equipment, and the pipeline. Operation at substantial load on a 24- hour/7 day-per-week basis or something approaching continual operation is generally important to the economic viability of a potential project.

The costs associated with retrofitting boilers will vary from unit to unit depending on boiler type, fuel use, and age of unit. Typical tiers of retrofits include:

- Incorporation of LFG in a unit that is co-firing with other fuels, where automatic controls are required to sustain a co-firing application or to provide for immediate and seamless fuel switching in the event of a loss in LFG pressure to the unit. This retrofit will ensure uninterruptible steam supply.
- Modification of a unit where surplus or back-up steam supply is available and uninterruptible steam supply from the unit is not required if loss of LFG pressure to the unit occurs. In this case, manual controls are implemented and the boiler operating system is not integrated in an automatic control system.

Both the smaller, lower-pressure firetube package boilers and larger, higher-pressure watertube package boilers are already in operation with LFG. Older field-erected brick set boilers have also been retrofitted for LFG fuel. Many major boiler manufacturers, such as Cleaver Brooks, Babcock & Wilcox, Nebraska, and ABCO, are represented in the population of boilers that have been converted for LFG service. Similarly, leading burner manufacturers (e.g., Todd, North American, and Coen) have provided specially designed LFG burners or have experience modifying standard natural gas burners for LFG service [7].

Another option is to improve the quality of the gas to such a level that the boiler will not require a retrofit. The gas is not required to have a Btu value as high as pipeline-quality, but the quality must be between medium and high. This option reduces the cost of a boiler retrofit and subsequent maintenance costs associated with cleaning because of deposits associated with use of medium-Btu LFG.

Examples of Successful Boiler LFG Energy Projects

NASA Goddard Space Flight Centre. In early 2003, NASA's Goddard Space Flight Centre in Greenbelt, Maryland, began firing LFG in three Nebraska watertube boilers, each capable of producing 18 000 kilograms/hr of steam. The gas is piped approximately 10 kilometres from the Sandy Hill Landfill to the boiler house at Goddard. NASA modified the burners and controls to co-fire LFG, natural gas, and oil; however, LFG provides the total firing requirement for approximately nine months of the year. NASA estimates an annual savings of more than 350,000 USD. Current NASA plans call for LFG use to continue for at least 10 years, with a possible extension to 20 years.

Cone Mills White Oak Plant. The LFG retrofit project at textile manufacturer Cone Mills' plant in Greensboro, North Carolina involved a very old (circa 1927) field-erected brick boiler. In this instance, the developers chose to install two new, multi-fuel burners. Full operation began in early 1997, with a steaming capacity of 13 500 kilograms per hour from the LFG fuel. Additional steam is provided as needed by co-firing with natural gas or fuel oil. The gas is supplied to the Cone Mills plant via a 6 kilometres pipeline originating at Greensboro's White Street Landfill. [11].

2.1.2 Infrared Heaters

A gas-fired infrared radiant heater burns gas to heat a radiating surface that emits infrared energy when at high temperature. Infrared energy is similar to visible light except that it lies between the visible and microwave sections of the electromagnetic spectrum. Like light, it travels in straight lines. Air does not absorb infrared energy well, so most of the heating is direct to solid objects. The heated objects then release heat to the air by convection and radiate some heat to surrounding objects.

Infrared radiant heaters are very effective for spot heating and are also used for heating large areas [12].

Landfill gas fired infrared heating systems offer many advantages for space heating requirements in the garages and another buildings local near the landfill. Advantages of radiant heating include:

- Radiant heat is not absorbed by the air, so it is highly efficient in areas that require frequent air changes or that have high infiltration rates.
- Radiant heating warms cold bodies directly without needing to heat up all of the air in the room or building. This rapid heat-up capability allows the heat to be off when the room or building is unoccupied, thus saving fuel.
- Radiant heating minimizes heat losses though the roof and roof vents. The energy is directed radiantly down toward the area needing heat and the minimal air heating minimizes stratification and the rise and escape of warm air.
- Radiant heating does not require forced air circulation in the room or building and thus minimizes circulation of airborne particles.
- Radiant heating allows zone control. Different areas can be heated to different temperatures as required.
- Radiant heat is directional. Very specific areas can be heated without heating an entire room or building.
- Radiant heat can be used effectively outdoors.

There are two kinds of gas infra-red heaters in use:

- ceramic, also called bright,
- pipe, also called dark or low-intensive.

The difference between ceramic and pipe infra-red heaters is that ceramic (bright) heaters usually operate at temperatures between 800^0C and $1,000^0$C, achieving their maximum radiation capacity at wave lengths from 2 to 4 μm, with efficiency reaching 93%. Pipe (dark) infra-red heaters operate at temperatures between 400^0C and 600^0C and release less than 10% energy in the form of radiation with wave length of 0.75 – 1.5 μm, approximately 30% in the 1.5 – 3 μm range, approximately 50% in the 3 – 6 μm range and less than 20% in the 6 – 12 μm range.

A pipe infra-red heater is composed of three main elements:

- gas burner,
- radiating pipe,
- screen.

The burners in ETD and ETS infra-red heaters are blow type, i.e. the burner's flame is lengthened by a low-rotation, low-noise fan, which works in clean feeding air.

Radiating pipes are made of special steel with some titanium added, and covered with black silicon emulsion, thanks to which they have extraordinary radiating capacity.

The basic element of ceramic infra-red heater is a burner made of perforated ceramic board covered with an aluminium reflector. On its surface a mixture of gas and air taken by the electro valve is burnt.

Radiation is directed to heated surfaces by means of highly-polished aluminium reflector.

Infrared heating using LFG is ideal when a facility with space heating needs is located near a landfill. Infrared heating creates high-intensity energy that is safely absorbed by surfaces that warm up. In turn, these surfaces release heat into the atmosphere and raise the ambient temperature. Therefore, large spaces such as industrial shelters, warehouses and facility buildings are most effectively and economically heated by gas-fired infrared heaters.

Infrared heating, using LFG as a fuel source, has been successfully employed at several landfill sites in Europe, Canada, and the United States. Infrared heaters require a small amount of LFG to operate and are relatively inexpensive and easy to install. Current operational projects use between 20 and 50 m^3/h.

The cost of infrared heaters depends on the area to be heated. One heater is needed for every 46 to 74 m^2. The cost of each heater, in 2007 dollars, is approximately 3,000 USD. In addition, the cost of the interior piping to connect the heaters within the building ceilings is approximately 20,000 to 30,000 USD [7].

There are many producers of infrared heaters, including those fired with gas fuel, in Europe and in the USA. Most heaters enable co-firing of pipeline natural gas and LPG (propane-butane) or propane. Some heaters are capable of firing natural gas of various sub-groups, such as GZ-35, GZ-41,5 or GZ-50. Infrared heaters which may fire GZ-35 sub-group natural gas with a heating value of 24 MJ/Nm^3 may also fire landfill gas provided such gas is free from siloxanes. A number of companies manufacture infrared heaters capable of firing GZ-35 sub-group natural gas, including Ambi-Rad, Detroit Radiant Products Co. and Gaz Industrie. The table below shows the specifications of infrared heaters manufactured by those companies [13].

Table 3. Selected specifications of infrared heaters

Manufacturer		**Ambi-Rad**	**Detroit Radiant Products**		**Gaz Industrie**
Type		Pipe infrared heaters	Ceramic infrared heaters	Pipe infrared heaters	Pipe infrared heaters
Series		ER	DR	EDX, EHL	BT
Capacity range [kW]		10 - 38	8.1 – 34.2	13.5 – 39.6	22 – 45
Symbol and capacity of a selected heater		ER, 22 kW	DK 75, 19.8 kW	EDX 40-75, 19.8 kW	BT, 22 kW
Radiation efficiency [%]		91	75	78	91
Fuels		GZ 50, GZ 35, GZ 41,5, propane-butane	GZ 50, GZ 35, propane	GZ 50, GZ 41,5 GZ 35, propane	GZ 50, GZ 35 LPG
Nominal fuel consumption	GZ 50 [m^3/h]	2.25	2.14	2.3	2.22
	LPG [kg/h]	1.51	1.68	1.60	1.64
Exhaust gas system		No exhaust gas removal – “through the roof” or “through the wall”	-	Wall-mounted or a ø100 pipe passing through the roof	No exhaust gas removal – “through the roof” or “through the wall”

Source: [14]

It must be stressed that there is no company worldwide which manufactures infrared heaters dedicated to LFG or agricultural biogas firing. In order to adjust the commercially available infrared heaters to use LFG, a number of requirements must be fulfilled:

- A full laboratory analysis of gas composition from the site. The site must be able to maintain the methane content of gas at more than 50% methane (some flexibility here as long as a heating value of at least 5.25 kWh/m^3 is met).
- The gas must be dry. Saturated gas is typically the norm with landfill gas. We can implement engineers refrigerated the gas to a dew point of 4^{o}C to remove water, and reheated to about 20^{o}C with good results.
- Landfill gas must be filtered through a 3 micron filter.
- Efforts should be made to eliminate contaminants (such as siloxanes) in the gas. Such contaminants can be deposited on components such as the flame sensor and can inhibit flame sensing and lead to nuisance heater lockout.
- Minimum gas supply pressure during operation must not be less than 20 mbar and a maximum of 60 mbar with the heaters turned off.
- Due to the reduced methane (heating value) content of the gas, the maximum heater input available is 30 kW.
- Accelerated heater maintenance and component (such as gas valve and flame sensor) replacement schedule is expected.

The first facility to use landfill gas to power infrared heaters was an active landfill in Frederick County (VA, USA). The project commenced in 2001/2002. Nine pipe infrared heaters were used to heat two facility buildings at the landfill, including a facility room (6 infrared heaters) and a warehouse (3 infrared heaters), using less than 51 m^3/h of landfill gas. The project utilised standard pipe infrared heaters retrofitted to fire landfill gas. Activated carbon drums were installed for LFG treatment prior to supply to the infrared heaters.

Another example of the use of infrared heaters in maintenance facilities is at I-95 Landfill in Virginia. Since 1990, Fairfax County has been collecting LFG at its I-95 Landfill and burning it to in two plants to generate enough electricity for about 5000 homes. The plants currently capacity is 3.2 MW of electricity each, making it the largest well field and landfill/electrical generation network in the State of Virginia. Some of the excess gas (approximately 1,700 m^3/h) is sent to the nearby Norman Cole Wastewater Treatment Plant where it is used to process sludge.

Although most of the LFG collected was being utilized, in 2005 the County decided to replace their existing propane-fired heating system onsite in the maintenance shop with LFG-fired infrared tube heaters to further maximize LFG utilization. The county connected small-diameter pipes to supply the LFG at 20 do 25 m^3/h for the five heaters to provide comfort heat to the onsite maintenance shelter. A simple treatment system was installed to remove any remaining moisture and contamination. Activated carbon drums were used to filter out siloxanes prior to delivery to the burners. After treatment, the gas is delivered to the heaters through a stainless steel piping system. The new LFG heating system improved the working conditions in the shop by heating objects, rather than air, which was quickly lost through the overhead doors, and saved money by avoiding the need to purchase of propane, which was previously used for heating the buildings. The use of LFG will reduce GHG emissions.

The heaters are standard, off-the-shelf type units, modified to operate on LFG (Picture 8 and 9). As the projects require only a small amount of LFG (typically 51 m^3/h), it's an ideal candidate for numerous landfills of any size: small, medium, or large. Less than 51 m^3/h LFG needed to heat about 604 m^2[14].

Picture 8. Infrared Heaters.
Source: [7].

Picture 9. Infrared Heaters.
Source: INiG picture.

2.1.3 Leachate Evaporation

The gas coming from the landfill can be used to evaporate leachate in situations where leachate is fairly expensive to treat.

The principle of Leachate Evaporation Systems (LESs) is simple and direct: use LFG collected at the site as an energy source to evaporate H_2O and combust the volatile organic compounds in the leachate. Depending on local requirements, the highly concentrated (hence very low volume) effluent is returned to the landfill or shipped off-site for disposal. Less concentrate and precipitate metals, primarily as salts, while stripping organics to a thermal oxidizer (e.g., flare) or reciprocating engine for destruction [15].

Evaporation is the only "treatment" technology available today that actually rids the water component from water-based waste streams. It can, for example, reduce the total volume of leachate to less than 5% of original volume [16].

Landfill-gas-fuelled evaporation is a technology that effectively integrates the control of landfill gas and landfill leachate. During recent years several forms of evaporation utilizing LFG as a fuel have emerged. The different types of evaporation fall into the categories of:

- evaporation vessels;
- spray-type dryers;
- direct injection-devices.

The most popular are evaporation vessels.

Several companies manufacture leachate evaporators. Depending on the manufacturer and the type of system selected, the volume of leachate evaporated by a single unit varies between 4.54 m^3/day and 113.56 m^3/day.

Evaporation of landfill leachate involves heating the leachate to produce a water vapour. Metals in the leachate concentrate and precipitate, primarily as salts, while the organics volatilize and stripped away by the water vapour.

The organics are transferred from the liquid leachate phase to the exhaust vapour phase by a process analogous to air stripping. Most evaporative systems use a modified commercial enclosed LFG flare for a downstream thermal oxidation stage to destroy the trace organics. Because the operating temperature of the evaporator is low (82 – 87^{o}C) most of the heavy metals do not vaporise.

Leachate evaporators apply energy developed by burning landfill gas to heat and vaporise leachate. The primary features distinguishing different commercial leachate evaporation systems are their methods for transferring heat to leachate and treating the exhaust vapour.

Direct transfer

Most commercial systems available use direct-contact evaporative technology, where heat transfers by means of direct contact between the leachate and the hot combustion gas. Depending on the manufacturer of the evaporator, the LFG combustion unit can be located:

- on top of the evaporation vessel—the hot combustion gases from the burner being directed downward through a downcomer pipe and the gases being bubbled through a small pool of leachate in the bottom of the vessel;
- on the side of the evaporator vessel—the hot combustion gases being exhausted through submerged horizontal burner tubes located within the vessel (a process known as "submerged combustion"). The hot gases inside the burner tubes are exhausted into the liquid through orifices located along the bottom of the burner tubes.

Indirect transfer

Alternatively, heat may be transferred indirectly from a landfill-gas burner through the walls of the heat exchanger to the leachate. A major concern in selecting the method used to transfer heat is to minimize harmful effects that precipitated solids may have on process efficiency. With solid heat transfer surfaces such as tubes, scale buildup will gradually reduce heat transfer efficiency. Cleaning then is required to restore performance.

Exhaust Vapour

Due to vapour stripping, the exhaust vapour from the leachate evaporator normally is laden with trace quantities of many different organic compounds. This exhaust vapour exits through a mist eliminator, which condenses large water droplets and returns most of the entrained liquid back into the evaporator. By removing large water droplets, the mist eliminator also removes much of the particulate matter from the evaporator exhaust.

The exhaust water vapour from the evaporators can carry the odour of the stripped organic compounds. To treat this condition, the vapour can be injected directly into a modified LFG enclosed flare. The enclosed flare burns LFG and the water vapour at high temperatures (that is, [> 870^{o}C] for a minimum of 0.5 seconds) before the exhaust gas is discharged to the atmosphere. This temperature and residence time allow for the destruction of more than 98% of the Volatile Organic Compounds (VOCs) present in the gas stream.

Data from the operations of different leachate evaporation facilities also have shown the emissions from the enclosed flare to:

- reduce the concentration of carbon monoxide (CO);
- very slightly increase in the concentration of nitrogen oxides (NO_x);
- little change in the concentration of sulphur oxides (SO_x).

Appraisal

Leachate evaporation systems are generally economically feasible only at sites where there is an adequate supply of LFG to evaporate the volume of leachate generated.

A typical landfill leachate requires approximately 0,15 Nm^{3}of LFG to evaporate one litre of leachate. Additional energy is required in evaporative systems that employ thermal oxidation (landfill gas flare) to treat exhaust gases. This second thermal energy requirement depends on the quantity and quality of vapour generated in the evaporation process. Typically, a flare requires approximately 0,53 Nm^3 of LFG for each litre of leachate evaporated. Thus, a reasonable estimate of the amount of LFG required to evaporate one litre of leachate and treat the resultant exhaust vapour in a downstream enclosed flare system is close to 0,7 Nm^3, assuming a methane concentration of 50%.

There are several variations of leachate evaporator systems. They differ only in the methods used to transfer heat to leachate and how the exhaust vapour is treated. One commercial design theme simply destroys the leachate vapours and LFG not consumed in the evaporation process in a slightly modified enclosed flare [Organic Waste Technologies, Inc. (OWT)]. Another variation combusts the evaporated vapours and LFG in an RIC (Reciprocating Internal Combustion) engine to produce electricity; the waste heat from the engines is used to aid in evaporating the leachate (Power Strategies L.L.C.) [15].

OWT offers two LESs. The LES is marketed through its Omni-Gen Technologies, Inc. subsidiary. OWT is also a licensee of the Technair system (Italy). A view of the LES is presented in picture 10. A process flow diagram for a 38 m^3 LES with typical flow quantities is presented in figure 9. Leachate is continuously fed to the evaporator vessel. A LFG-fired burner introduces hot gas into the leachate as fine bubbles below the surface (gas sparging) and direct heat transfer occurs between the liquid and hot gas. The leachate is maintained at 82 – 88^{o}C. Direct contact of hot gases with leachate acts to strip most of the organic compounds within the leachate to the vapour phase. Organics are transferred from the liquid leachate phase to the exhaust vapour phase by a process analogous to air stripping (i.e., contaminants partition between the vapour and liquid phases according to their respective vapour pressures and concentrations within the liquid). As the process occurs at elevated temperatures, the stripping action is generally more efficient than that obtained with most conventional air strippers operating at ambient temperatures.

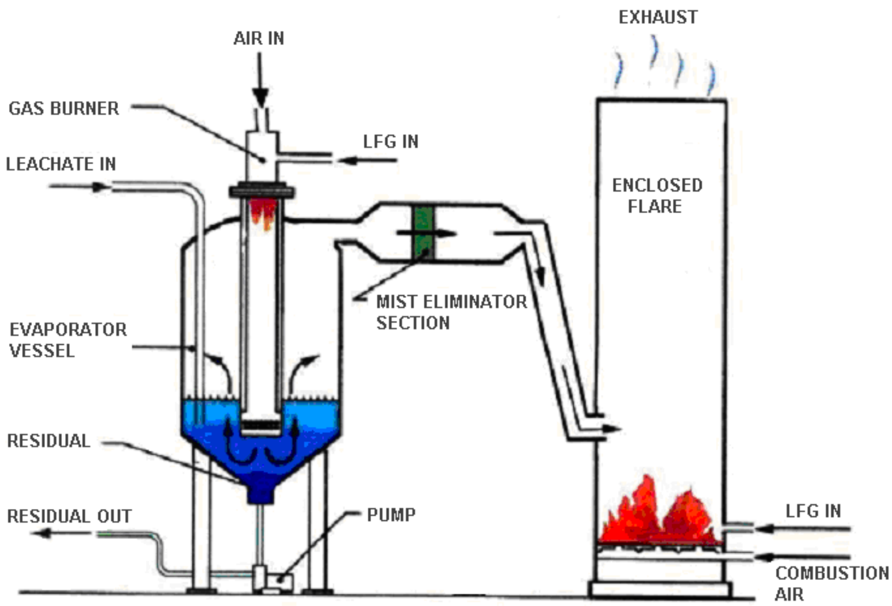


Figure 9. Leachate Evaporation Diagram.
Source: [7].

Picture 10. Leachate Evaporation System.
Source [7].

Evaporation may offer the potential to deal with leachate problem effectively in one principal unit operation at the landfill site. In addition, two principal by-products of landfill operations, leachate and gas, could be used together beneficially in one process [17]. After evaporation the volume of the concentrated residual will be a small fraction of the original leachate and could be recycled back to the landfill. Volatile components in leachate that go in the exhaust air stream could be treated separately, if required [18].
Conventional treatment of landfill leachate may require several unit operations to remove the various contaminants to acceptable levels. Leachate treatment by evaporation may offer the advantage of dealing with the leachate on the landfill site by employing fewer unit operations as compared to a conventional treatment process composed of several sequential unit operations. Evaporation allows separation of volatile from non-volatile components. Solids and metals can be concentrated into a small volume after evaporation. [18]. Landfill gas produced by the decomposition of landfill refuse might be used as an energy source for evaporation of leachate [17].

Leachate evaporation is a good option for landfills where leachate disposal in a publicly owned treatment works plant is unavailable or expensive. Evaporators are available in sizes to treat 38 - 114 m^3/day of leachate. LFG is used to evaporate leachate to a more concentrated and more easily disposed effluent volume.

The system costs USD 300,000 to USD 500,000 to put in place with operations and maintenance costs of USD 70,000 to USD 95,000 per year. When a system is owned and operated by a third party, long term contracts will typically assess costs based on the volume of leachate evaporated. Some economies of scale are realized for larger size vessels. A 114 m^3/day evaporator costs USD 16 per cubic meter, while a 76 m^3/day unit is USD 31 per cubic meter and a 38 m^3/day unit is USD 53 per cubic meter [7].

2.2 Electricity Generation

Producing electricity from LFG continues to be the most common beneficial use application, accounting for above 90% LFG energy projects in Poland. Electricity can be produced by burning LFG in an internal combustion engine, a gas turbine, or a microturbine.

2.2.1 Reciprocating Engines

On landfills, electricity is usually produced by gas-powered spark-ignition reciprocating engines, that is internal combustion engines (four-stroke engines) commonly used in vehicles and machinery. The name refers to four stages of the engine's operation: intake of air or air-and-fuel mixture, compression, power and exhaust. For each cycle, there are two complete rotations of the crankshaft. In other words, in a four-stroke engine, the piston makes four strokes per working cycle. The internal combustion engine has an intake valve, through which the air-and-fuel mixture (or air) is introduced into the cylinder, and an exhaust valve, through which exhaust gases escape from the cylinder.

Gas-powered reciprocating engines, also called gas-powered internal combustion engines, are modified versions of medium- and high-speed engines powered by liquid fuels. The modifications applied in gas-fuelled engines typically include: change in the shape of head and the top part of pistons, adding a gas and liquid fuel system, and expansion of the engine cooling system and the exhaust heat removal system [20].

There are four cycles: induction, compression, power and exhaust.

Stroke I – INDUCTION

The piston descends from the top dead centre (TDC) to the bottom dead centre (BDC), producing negative pressure inside the cylinder. The intake valve is open, allowing air-and-fuel mixture (or fresh air, in the case of direct injection) to be drawn from the intake system (carburettor, or single- or multi-point fuel injection) through the intake port situated behind the intake valve. The air-and-fuel mixture is injected into the cylinder into a space between the piston and the cylinder head. As soon as the piston passes BDC, the intake valve closes.

Stroke II – COMPRESSION

The piston returns to the top of the cylinder compressing the air-and-fuel mixture. Both the intake and exhaust valves are closed. Under significant pressure, the mixture is compressed to (typically) less than one tenth of its original volume. Combustion takes place before the air-and-fuel mixture is compressed to its minimum volume (1–2 mm, or, at approximately 5 degrees of the crankshaft rotation, before the piston reaches TDC). The mixture is to be completely combusted exactly as the piston passes TDC to be driven back by the expanding exhaust gases which initiate the power stroke.

Stroke III – POWER

In high-speed engines and electronic direct fuel injection engines, shortly before the piston reaches TDC, fuel is injected and spontaneous or spark ignition occurs. Both the intake and exhaust valves are closed. The piston is driven back with a powerful force, because a pressure up to 100 bar is created inside the chamber following ignition (which sometimes corresponds to a five-tonnes pressure on the piston). The forces must be transferred from the bottom of the piston, through the connecting rod to the crankshaft. This forces the piston to move to BDC. One stroke of engine must create enough power to complete the remaining three strokes. Therefore, the more cylinders an engine has, the smother it runs.

Stroke IV - EXHAUST

Before the piston reaches BDC, the exhaust valve opens, and the exhaust gases, not yet fully expanded, escape from the cylinder through the exhaust system. The cylinder moves upwards toward TDC and pushes the remaining gas out of the cylinder through the open exhaust valve. As the piston reaches TDC, the exhaust valve is closed, the intake valve opens and the cycle starts again.

Figure 10 represents a diagram showing a full cycle of a four-stroke engine.

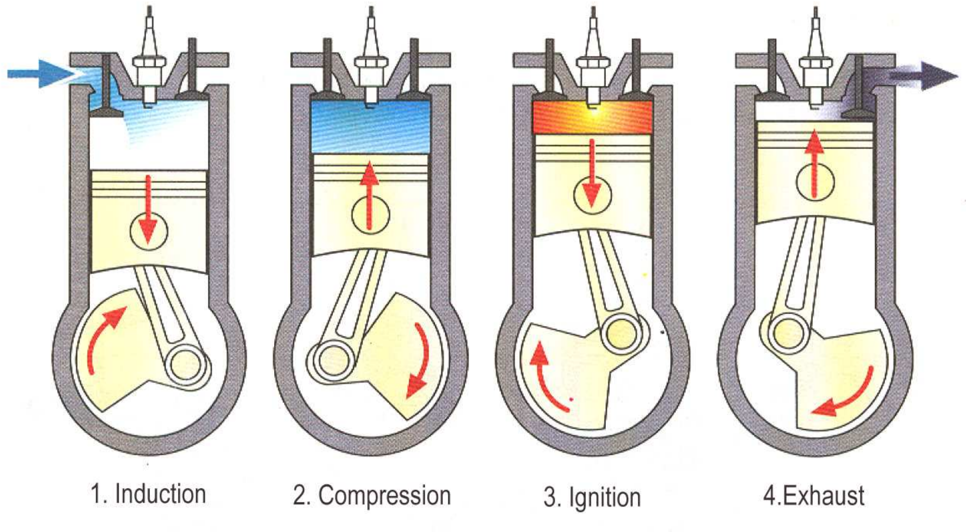


Figure 10. 4-stroke engine cycle diagram.
Source: [21].

To ensure efficient operation of an LFG supply and electricity generation system, the gas fuel (landfill gas) must meet the following requirements (Table 4).

Table 4. Limiting values and maximum permissible concentrations of certain fuel components for selected manufacturers.

Constituent	**Jenbacher**	**Deutz**	**Caterpillar**	**Waukesha**
Calorific value and variability	Maximum variation: <0.5 % CH_4 (v/v) per 30 seconds	14.4 MJ/Nm^3	15.7-23.6 MJ/Nm^3 (recommended range)	>15.73 MJ/Nm^3
Total sulphur content	2,000 mg/Nm^3 CH_4 (with catalyst) 1,150 mg/Nm^3 CH_4 (without catalyst) (total S as H_2S)	<2200 mg/Nm^3 CH_4	2,140 mg H_2S per Nm^3 CH_4 (total S as H_2S)	<715 mg/Nm^3 CH_4 (total S bearing compounds)
H_2S content	-	<0,15 % v/v	-	-
Ammonia	<55 mg/Nm^3 CH_4	-	<105 mg NH_3 per Nm^3	-
Total Cl content	See: Sum of Cl and F	<100 mg/Nm^3 CH_4	See: Sum of Cl and F	See: Sum of Cl and F
Total F content	See: Sum of Cl and F	<50 mg/Nm^3 CH_4	See: Sum of Cl and F	See: Sum of Cl and F
Sum of Cl and F	Without catalyst: <100 mg/Nm^3 CH_4 (weighted as one part Cl	<100 mg/Nm^3 CH_4	<713 mg Cl per Nm^3 CH_4 (total halide compounds as Cl)	300 mg/Nm^3 CH_4 (total organic halides as Cl)

Constituent	Jenbacher	Deutz	Caterpillar	Waukesha
	and two parts F) without warranty restriction; 100-400 mg/Nm^3 CH_4 with warranty restriction; >400 mg Nm^3 CH_4 no warranty at all With catalyst: 0 mg/Nm^3 CH_4			
Silicon (Si)	Old standard Without catalyst: <20 mg/Nm^3 CH_4 without warranty restriction; (>20 mg/Nm^3 CH_4 with restriction) New standard Without catalyst: see below [1] With catalyst (old or new standard): 0 mg/Nm^3 CH_4	<10 mg/Nm^3 CH_4	<21 mg/Nm^3 CH_4 [2]	<50 mg/Nm^3 CH_4 total siloxanes (models with prechamber fuel system only)[3]
Dust	<50 mg/Nm^3 CH_4 (particles <3 µm)	<10 mg/Nm^3 CH_4 (particles maximum 3-10 µm)	<30 mg/Nm^3 CH_4 (particles <1 µm)[2]	Removal of particles >0.3 µm
Oil / residual oil	<5 mg/Nm^3 CH_4	<400 mg/Nm^3 CH_4 (oil vapours $>C_5$)	<45 mg/Nm^3 CH_4 (oil)	<2% v/v liquid fuel hydrocarbons at coldest inlet temperature
Miscellaneous	-	Project specific limits: hydrocarbon solvent vapours	-	No Glycol
Relative humidity / moisture	<80% with zero condensate	<60 - 80%	<80% at minimum fuel temperature	Zero liquid water: recommend chilling gas to 4ºC followed by coalescing filter

Constituent	Jenbacher	Deutz	Caterpillar	Waukesha
				and then reheating to 29 - 35ºC; dew point should be at least 11ºC below temperature of inlet gas
Pressure at inlet	Turbocharged engines: 80 - 200 mbar	Up to 2 000 bar	-	-
-	Pre-combustion chamber: Models 612-616: 2,500 – 4,000 mbar Model 620: 3,000 – 4,000 mbar	-	-	-
Gas pressure fluctuation	<10 mbar/second	< ±10 % of set value at a frequency of <10 per hour	-	-
Inlet gas temperature	<40 ºC	10-50 ºC	-	> -29 ºC and <60 ºC
CH_4 (% v/v)	-	40 %	Recommended ratio of CH_4: CO_2 is 1.1 – 1.2	-
Methane[4]	-	~140 for landfill gas	-	-
Hydrogen (% v/v)	-	-	-	<12 %

1 Relative limiting value of <0,02 according to the following calculation (without catalyst):
Relative limiting value = (mg/kg Si in engine oil) x (total oil quantity in litres) / (engine power in kW) x (oil service time in hours)

2 Specifications stated by manufactures in mg/MJ were converted to mg/Nm^3 CH_4 assuming a calorific value for CH_4 of 37.5 MJ/Nm^3.

3 Specifications stated by manufactures in mg/l landfill gas were converted to mg/Nm^3 CH_4 assuming 50 per cent CH_4 (v/v).

4 Methane number for natural gas is typically between 70 and 92; methane 100 (knuckles) and hydrogen 0 (knock-friendly).

Source: [8].

Among the many components of landfill gas, sulphur, chlorine and fluorine compounds are the most harmful to equipment and the environment. Combustion products such as SO_2, HCl and HF work to the detriment of machinery and the environment.

When combusted in reciprocating engines, LFG containing sulphur and chlorine compounds shorten the useful life of engine oils and impact the efficiency of catalysts. Their harmful

effects include corrosion of LFG collection pipes, fittings, meters, crankshaft, camshaft, gas-powered engine and bearings. A landfill gas with a high concentration of sulphur requires treatment.
One should also note that landfill gas is saturated with water vapour. Drying LFG prior to its utilisation will limit corrosion of gas-fired units.
In addition, an engine will run for a longer period of time when it is properly operated. Continuous operation is best for an engine. Frequent switching on and off adversely affects engine operation because condensate accumulates as the engine cools down, leading to acid formation [22].

Employing reciprocating engines for combined heat and power (CHP) generation yields very good results. CHP plants using gas-powered reciprocating engines usually produce hot water or saturated steam. Heat is recovered from the heat exchanger on engine casing, oil cooler and exhaust heat exchanger (Figure 11).

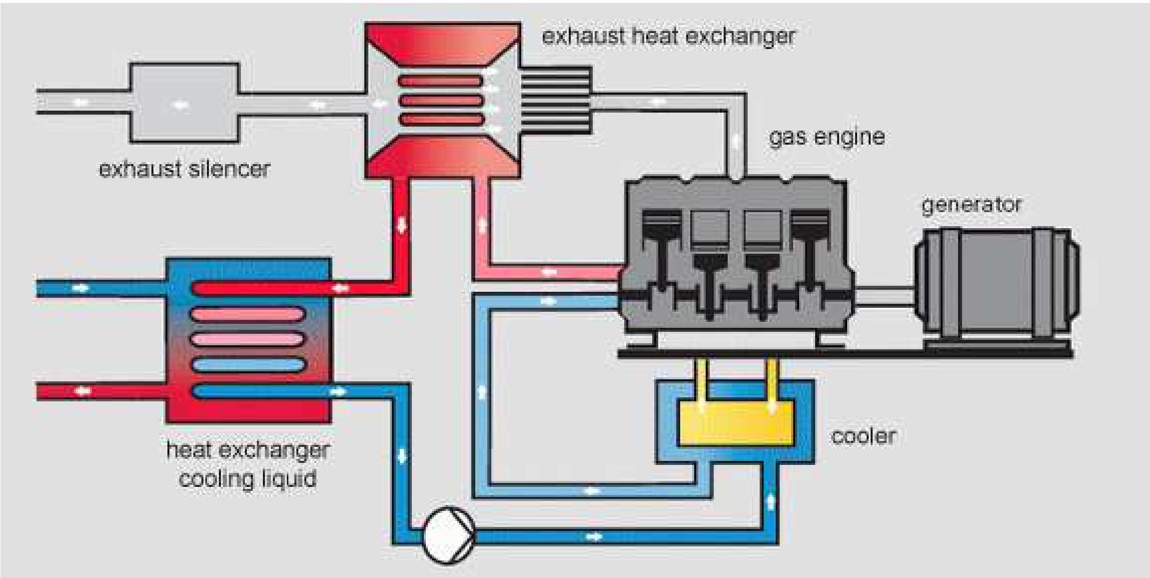


Figure 11. Cogeneration with gas engine diagram.
Source: [23].

A basic CHP system comprises a combined heat and power unit, power safety system, auxiliary drive switchgear, oil system and cooling system.
The working engine powers a generator that produces electricity. During operation, the reciprocating engine warms up, producing heat which is recovered by the oil cooling system, and emits large amounts of heat to the atmosphere in the form of exhaust gases. In a CHP system, both types of heat are recovered by a heat exchanger system. Both types of heat are

summed up and transmitted outwards by a water- or glycol-based system, in order to be utilised. The auxiliary drive switchgear ensures appropriate specifications of water or glycol at the inlet and outlet of the CHP unit by controlling the valves, the emergency cooling system, and by constantly monitoring the water specifications. If water at the inlet to the CHP unit is too hot, the switchgear directs some water to the cooling system. When the incoming water at the CHP unit is too cold, the by-pass warms up water up to the required temperature. All the operations are carried out to achieve the required temperature of water or glycol at the outlet of the CHP unit. In CHP units, water temperature is 70°C at the inlet and 90°C at the outlet [24].

Another important system of an engine is the gas-and-air system. For its operation, a reciprocating engine needs air which, together with the fuel (gas), and combusted in the engine's combustion chambers. A gas-and-air mixture is created by the gas-and-air mixer, into which air is drawn through a filter. The gas feeding system comprises a gas control system with a zero pressure regulator, and a precise system for metering gas flow by means of a metering valve. The air-fuel ratio is selected based on the result of the metering. The gas metering valve is controlled by a lambda system comprising an oxygen sensor and an electronic gas lambda system.

The third system, apart from the water and the gas-and-air systems, is the oil system. Each reciprocating engine requires oil to lubricate the moving parts. A small amount of oil may enter the combustion chamber where it is combusted along with the fuel. Therefore, an external oil system must be provided, to supplement oil in case of shortages, enabling continuous operation of the CHP unit [24].

The fourth system in a CHP unit is the power system. To enable electricity produced by the generator to be beneficially used, suitable devices must be installed at electricity collection to protect the generators against overloading and short-circuit conditions. The devices must be suitably connected to be capable of switching the generator on and off. The system must protect the generators against the so-called motor operation which is capable of destroying the entire CHP unit. A power safety system switchgear is employed to cope with the tasks referred to above [24].

Picture 11. Gas-powered Jenbacher engine with 526 kW power output.
Source: [25].

The CHP system is assumed to produce hot water, although the multi-megawatt size engines are capable of producing low-pressure steam. Table 5 provides cost estimates for combined heat and power applications. These cost estimates include interconnection and paralleling. The package costs reflect a generic representation of popular engines in each size category. The interconnect/electrical costs reflect the costs of paralleling a synchronous generator, though many 100 kW packages available today use induction generators that are simpler and less costly to parallel labour/materials represent the labour cost for the civil, mechanical, and electrical work and materials such as ductwork, piping, and wiring. Project and construction management also includes general contractor markup and bonding and performance guarantees. Contingency is assumed to be 3% of the total equipment cost in all cases [26].

Table 5. Estimated Capital Cost for Typical Gas Engine Generators in Grid Interconnected, Combined Heat and Power Application ($/kW)

Nominal Capacity (kW)	100	300	800	3000	5000
	Costs (USD/kW)				
Equipment					
Gen Set Package	260	230	269	400	450
Heat Recovery	205	179	89	65	40
Interconnect/Electrical	260	90	40	22	12
Total Equipment	**725**	**499**	**398**	**487**	**502**
Labour/Materials	359	400	379	216	200
Total Process Capital	**1,084**	**899**	**777**	**703**	**702**

Project and Construction Management	235	158	121	95	95
Engineering and Fees	129	81	45	41	41
Project Contingency	43	34	28	25	25
Project Financing (interest during construction)	24	25	31	55	55
Total Plant Cost (USD/kW)	**1,515**	**1,197**	**1,002**	**919**	**919**

Source: Energy Nexus Group.

Maintenance can be either done by in-house personnel or contracted out to manufacturers, distributors, or dealers under service contracts. Full maintenance contracts (covering all recommended service) generally cost between 0,7 to 2,0 cents/kWh depending on engine size, speed, and service. Many service contracts now include remote monitoring of engine performance and condition and allow for predictive maintenance. Service contract rates typically are all-inclusive, including the travel time of technicians on service calls.

Recommended service is comprised of routine short interval inspections/adjustments and periodic replacement of engine oil and filter, coolant and spark plugs (typically 500 to 2,000 hours). An oil analysis is part of most preventative maintenance programs to monitor engine wear. A top-end overhaul, generally recommended between 8,000 and 30,000 hours of operation, entails a cylinder head and turbocharger rebuild. A major overhaul after 30,000 to 72,000 hours of operation involves piston/liner replacement, crankshaft inspection, bearings, and seals [26].

There are many manufacturers worldwide which produce generators. Major manufacturers, offering highly-reliable generators and a wide range of products, include CATERPILLAR (USA) and Jenbacher Energie (Austria). DEUTZ (Germany) and WAUKESHA (USA) are also worth mentioning.

CATERPILLAR

Caterpillar is the world's largest manufacturer of medium speed engines, as well as one of the world's largest manufacturers of high speed diesel engines. Generators are available in versions without casing, and versions in factory-made noise-protection casings, resistant to weather conditions. Table 6 shows gas-powered generators with power output ranging from 579 to 4,579 kW made by Caterpillar.

Table 6. Gas powered generators made by Caterpillar

POWER OUTPUT kVA	**POWER OUTPUT** KW	**MODEL**
579	463	G3508
964	771	G3512
1,284	1,027	G3516A
1,364	1,091	G3516B
1,805	1,444	G3520B
2,000	1,600	G3516E
2,491	1,993	G3520C
3,411	2,729	G3612
4,579	3,663	G3616E

Source: INiG study.

Picture 12. Landfill in Monterey, Marina, California - Caterpillar 3520C engine.
Source: INiG photo.

JENBACHER

GE Jenbacher based in Jenbach, Austria, is a major manufacturer of gas-powered engines. Jenbacher manufactures several thousand engines of various sizes for a wide range of customers from every part of the world. It boasts a long history of operation and has produced generators featuring gas-powered engines with electricity output ranging from 250 to 4,000 kW and heat output from 300 to 4,000 kW, achieving high general efficiencies up to 90% when applied in CHP plants. Individual units may be combined to form systems, comprising up to between ten and twenty units, thus creating many possibilities for an optimum solution, adjusted to changing demand for electricity, heat and cooling, and highly economical. Jenbacher manufactures large-size engines fed on natural gas or other gases, including liquid gases, as well as engines fuelled with gas mixtures, including lean mixtures containing components which are onerous or difficult to handle, and originate from such processes as coking, refining and other chemical processes; as well engines fed on gas from waste disposal and LFG etc. Gas-powered engines produced by GE Jenbacher may have an open construction or may be enclosed in a container; they are available individually or in combinations. Jenbacher engines are highly endurable, and have low operating costs, quick return rates, short start-up time and low level of oscillations. They are capable of working in an automatic mode with remote control, including remote control through the Internet; in full synchronisation with an external or internal electrical network; they conform to standards regarding noise emission and exhaust gas composition.

Picture 13. Landfill In Monterey, Marina, California - Jenbacher 320 engine.
Source: INiG photo.

An example of landfill gas use to fuel reciprocating engines is the landfill at Puente Hills, California, USA. A conventional convection power plant (steam turbines) using landfill gas to power steam boilers was developed first. The 46 MW plant is still operational and works in a continuous cycle. In order to utilise the large amount of landfill gas recovered from the landfill, in 2006 two additional Caterpillar 3616 engines (with a total capacity of 8 MW) fed on landfill gas were installed at the landfill.

Picture 14. Caterpillar 3616 at Puente Hills landfill.
Source: INiG photo.

Another such project is the municipal waste landfill at Barycz (Poland). The LFG energy undertaking in Barycz, utilising gas engines with spark ignition, is one of the oldest and largest projects of this type in Poland. The gas recovered from the landfill is used to power generating units with a total capacity of 1,325 kW (2x250 kW, 375 kW and 450 kW). The power units could be located in close proximity to office and service buildings because they are enclosed in containers. The generated electricity is sold to the grid while the heat is consumed on site.

Picture 15. Reciprocating engines enclosed in containers at Barycz landfill.
Source: INiG photo.

2.2.2 Turbines

Gas turbines operate based on a thermodynamic Brayton Cycle. The term "gas" refers to the atmospheric air that is taken into the engine and used as the working medium in the energy conversion process. This atmospheric air is first drawn into engine where it is compressed, heated, and then expanded, with the excess of power produced by the expander over that consumed by the compressor used for power generation. The power produced by an expansion turbine and consumed by a compressor is proportional to the absolute temperature of the gas passing through the device [26].

The majority of gas turbines presently operating at landfills are simple cycle, single shaft machines. A LFG gas turbine is very similar to a natural gas turbine except that, because of the medium heating value, twice the number of fuel regulating valves and injectors are used. Gas turbines require a high pressure fuel supply in the range of 11 to 14 bars. Using a fuel gas compressor to supply such pressure can consume a significant portion of the power being generated (parasitic losses) [27].

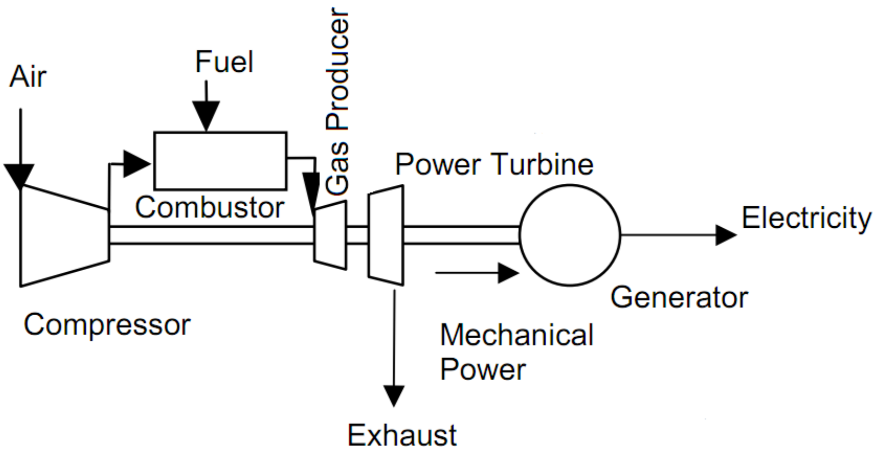


Figure 12. Components of a Simple-Cycle Gas Turbine.
Source: [26].

A typical landfill gas turbine has the following basic components [28]:

- Compressor - the compressor takes in outside air and then compacts and pressurizes the air molecules through a series of rotating and stationary compressor blades.
- Combustor - in the combustor, fuel is added to the pressurized air molecules and ignited. The heated molecules expand and move at high velocity into the turbine section.
- Turbine - the turbine converts the energy from the high velocity gas into useful rotational power though expansion of the heated compressed gas over a series of turbine rotor blades.
- Output Shaft & Gearbox - rotational power from the turbine section is delivered to driven equipment through the output shaft via a speed reduction gearbox.
- Exhaust - the engine's exhaust section directs the spent gas out of the turbine section and into the atmosphere.

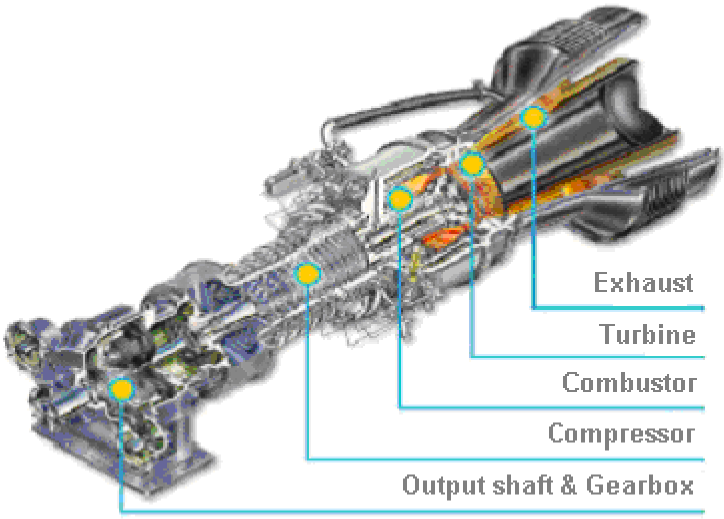


Figure 13. Cross section of a Titan 130 Single shaft gas turbine for power generation application.
Source: [28].

Gas turbines are one of the cleanest fossil-fuelled power generation equipment commercially available. Many gas turbines burning gaseous fuels feature lean premixed burners (also called dry low-NO_x combustors) that produce NO_x emissions below 25 ppm, and simultaneous low CO emissions in the 10 to 50 ppm range.

The turbine systems require more inspections, cleaning and general maintenance with LFG. It requires higher level of LFG treatment for the removal of siloxanes [29]. This additional gas treatment increases project costs.

Simple-cycle gas turbine for power-only generation has efficiencies approaching 40 % and overall CHP efficiencies of up to 80 % [26].

Gas Turbines can be used in combined heat and power (CHP) operation which is a simple cycle gas turbine with a heat recovery heat exchanger which recovers the heat in the turbine exhaust and converts it to useful thermal energy usually in the form of steam or hot water and combined cycle operation in which high pressure steam is generated from recovered exhaust heat and used to create additional power using a steam turbine.

Gas turbines are mostly used in combined heat and power systems of more than 1 MW (only a few types of gas turbines of less than 1 MW are available). At the same time, it should be borne in mind that units of the smallest size feature low efficiencies and relatively high unit investment costs (upwards of USD 500/kW_{el}) [30].

Compared with a piston engine of the same size, a gas turbine features lower generation efficiency and a markedly lower power to heat ratio (cogeneration ratio). On the other hand, a gas turbine is significantly lighter (e.g. a 1 MW turbine weighs approx. 1 tonne, whereas a piston engine of the same size – approx. 10 tonnes) and smaller. In a gas turbine, the only source of heat is exhaust gas, which can be converted to useful energy. Figure 14 shows a gas turbine-based hot water generation system [30].

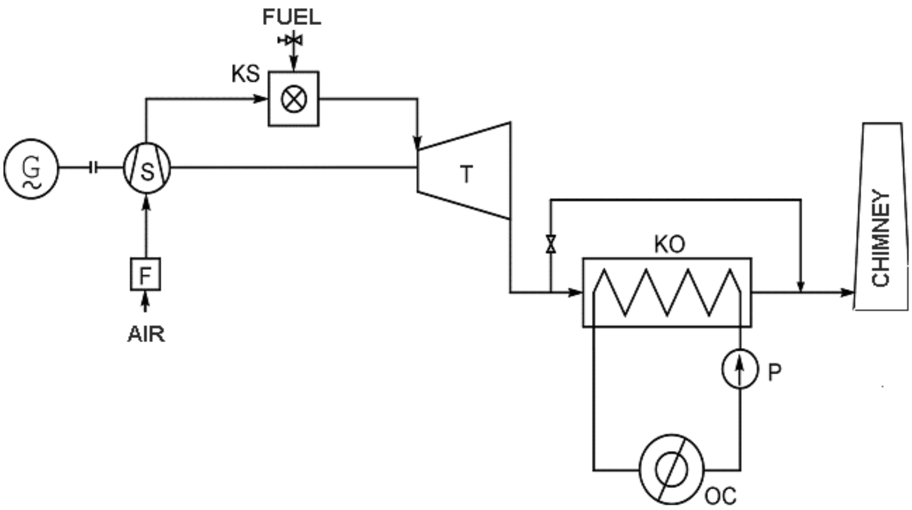


Figure 14. Simple gas turbine-based cogeneration system used for hot water production (G – generator, KS – combustion chamber, T – turbine, S – compressor, KO – waste-heat boiler, P – pump, OC – heat exchanger, F – filter)
Source: [30].

Gas turbines are available in sizes ranging from 500 kW to 250 MW, however at landfills most LFG energy projects, are a minimum of 3 MW to more than 5 MW (where gas flows exceed a minimum of 2,300 Nm^3/h) [7, 26].

The most common gas turbine in operation at LFG recovery projects in USA is the Centaur, manufactured by Solar Turbines, a subsidiary of Caterpillar. The net rated generating capacity is 3000 kW; the gross capacity (prior to parasitic losses) is 3,500 kW or more, depending on the model and its application.

Solar gas turbine power generation packages have the following standard features [28]:

- Industrial grade three-phase induction generator, both 50 Hz and 60 Hz;
- Epicyclic gearbox between turbine and generator;
- PLC-based Turbotronic™ control system to oversee both turbine and generator operations;
- Lube oil system for turbine and generator, including lube oil cooler;
- Turbine air filtration system;
- Electric start system;

- Operator and maintenance personnel training.

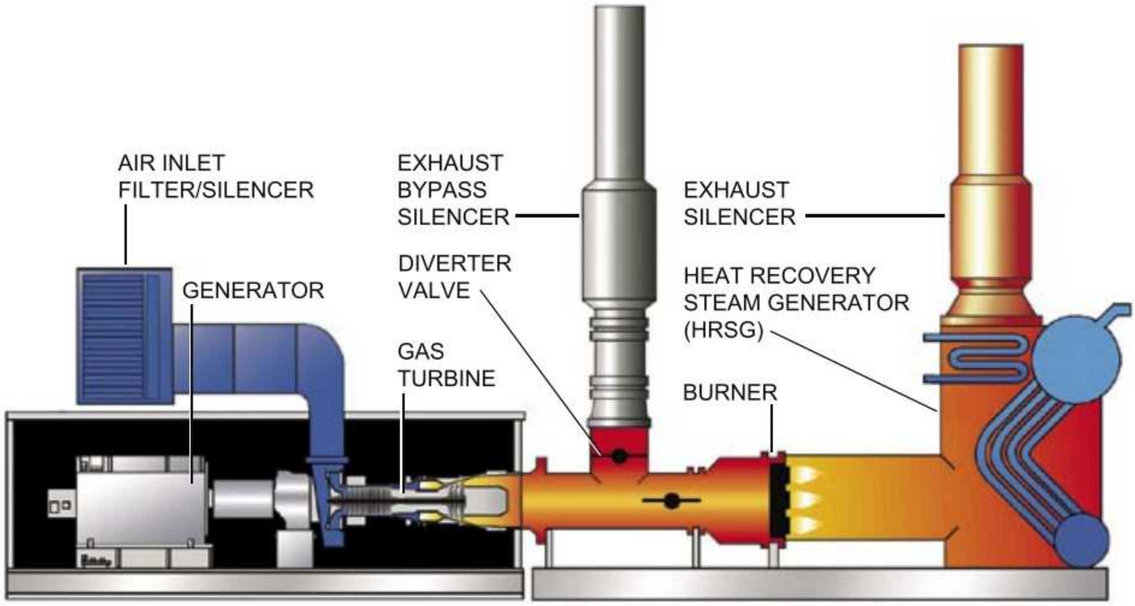


Figure 15. Solar Gas Turbine.
Source: [28].

Table 7 provides cost estimates for four typical gas turbine CHP systems. It should be note that installed costs can vary significantly depending on the scope of the plant equipment, geographical area, competitive market conditions, special site requirements, emissions control requirements, prevailing labour rates, whether the system is a new or retrofit application etc.

Table 7. Estimated Capital Costs for Typical Gas Turbine-Based CHP.

Nominal Capacity (MW)	**1**	**5**	**10**	**25**
	Costs (Thousands of USD)			
Equipment				
Turbine Genset	675	1,800	4,000	11,500
Heat Recovery System Generators	250	450	590	1,020
Water Treatment System	30	100	150	200
Electrical Equipment	150	375	625	990
Other Equipment	145			
Total Equipment	**1,250**	**3,040**	**5,940**	**14,860**

Nominal Capacity (MW)	1	5	10	25
Materials	144	346	689	1,490
Labour	348		1,150	1,875
Total Process Capital	1,742	4,265	8,381	20,065
Project/ Construction Management	125	304	594	1,486
Engineering	63	153	260	537
Project Contingency	87	215	419	1,005
Project Financing	129	32	25	21
Total Plant Cost (USD/kW)	**2,146**	**5,253**	**10,272**	**24,576**
Actual Turbine Capacity (kW)	1,210	5,200	10,600	28,600
Total Plant Cost per net kW (USD)	1,781	1,010	969	859

Source: [26].

Maintenance costs are about 2 cents per kWh. Daily maintenance includes visual inspection by site personnel of filters and general site conditions. Routine inspections are required every 4000 hours to insure that the turbine is free of excessive vibration due to worn bearings, rotors, and damaged blade tips.

A gas turbine overhaul is needed every 25,000 to 50,000 hours depending on service. A typical overhaul consists of dimensional inspections, product upgrades and tasting of the turbine and compressor, rotor removal [26].

A very good example of a project is the power facility in Archbald, Pennsylvania USA. The plant design started in September of 2008. The facility consists of two 4.6 MWe landfill gas fired Mercury 50 recuperated gas turbines, fuel gas compression, and siloxane removal. The facility design included a provision for additional two gas turbines and future turbine exhaust heat recovery for steam production. The landfill gas for the two turbines is provided from two separate landfills and delivered to the site through 40 km of piping. At full operation, the plant produces almost 30 MW of electricity from landfill gas [28].

Picture 16. Landfill gas-fuelled power facility in Archbald, Pennsylvania.
Source: [28].

2.2.3 Mikroturbines

Microturbines are small combustion turbines that can be used in stationary power generation application. The basic components of a microturbine are the compressor, turbine generator, and recuperator.

In a microturbine, the combustion air (inlet air) is compressed using a compressor and then is preheated in the recuperator using heat from the turbine exhaust in order to increase overall efficiency. The landfill gas is pressurized to 5,5 bar then chilled to 4 ˚C to remove moisture. The reheated gas temperature is kept at a minimum of – 8˚C above its dew point. Further treatment of the gas includes reducing siloxane and H_2S content. All other gaseous components are destroyed in the microturbine combustion chamber. The heated air and LFG are burned in the combustor chamber, and the release of heat causes the expansion of the gas. The expanding gas, sent through a gas turbine, turns the generator. Then generator is producing electricity [26, 31, 32].

A general schematic of the microturbine process and cross-section of the microturbine are shown in figure 15 and 16.

A typical landfill gas microturbine system has the following components [32]:

- LFG compressor(s);
- Gas pretreatment equipment;
- Microturbine(s);
- Motor control center;
- Switchgear;
- Transformer.

Microturbine requires LFG treatment to remove moisture, siloxanes, and other impurities. The landfill gas pretreatment steps depend on the characteristics of the LFG and vary by microturbine manufacturer. In some cases, the gas is chilled to remove moisture and condensable impurities, and is reheated to supply gas above dew point temperature to the microturbine. In addition to moisture removal, some manufacturers require an adsorption step using activated carbon to remove virtually all impurities [32].

Most of manufacturers for example Capstone have established a fuel specification that requires less than 5 ppbv (~ 0,03 mg/m^3) of siloxane. The prolonged exposure to untreated LFG results in a progressive loss of performance due to silica buildup in the combustor and recuperator [9]. Capstone's MicroTurbines can accept high levels of hydrogen sulphide (H_2S). For example the Capstone CR30 can accept H_2S levels as high as 70,000 ppm, and the CR65, CR200, and CR1000 are able to operate with up to 5,000 ppm [33].

Other manufacturer e.g. Ingersoll-Rand has not confirmed a problem with siloxanes, but maintains an official fuel restriction of 10 ppbv of siloxane [9].

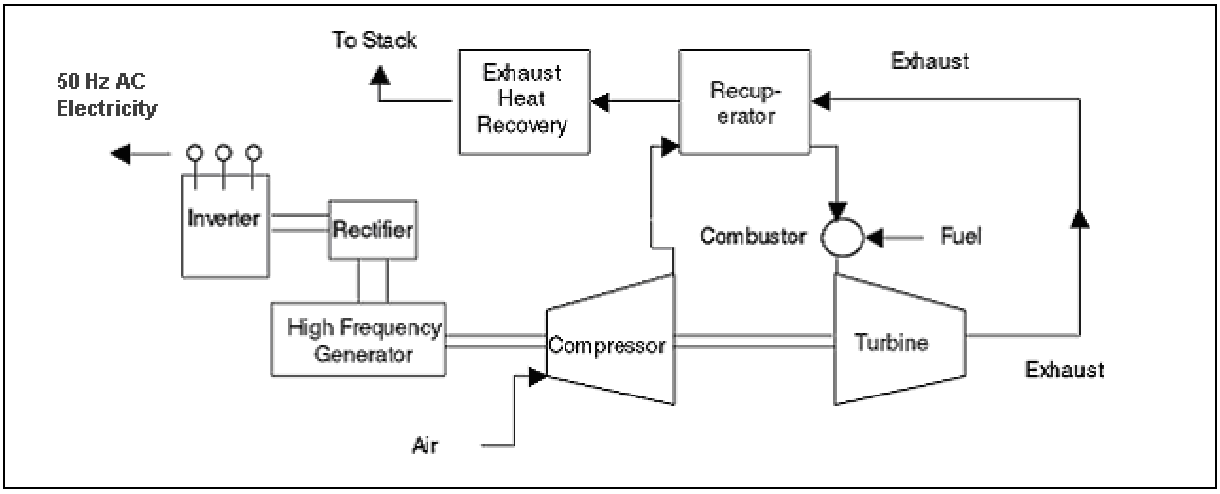


Figure.16. Microturbine process schematic
Source: [26]

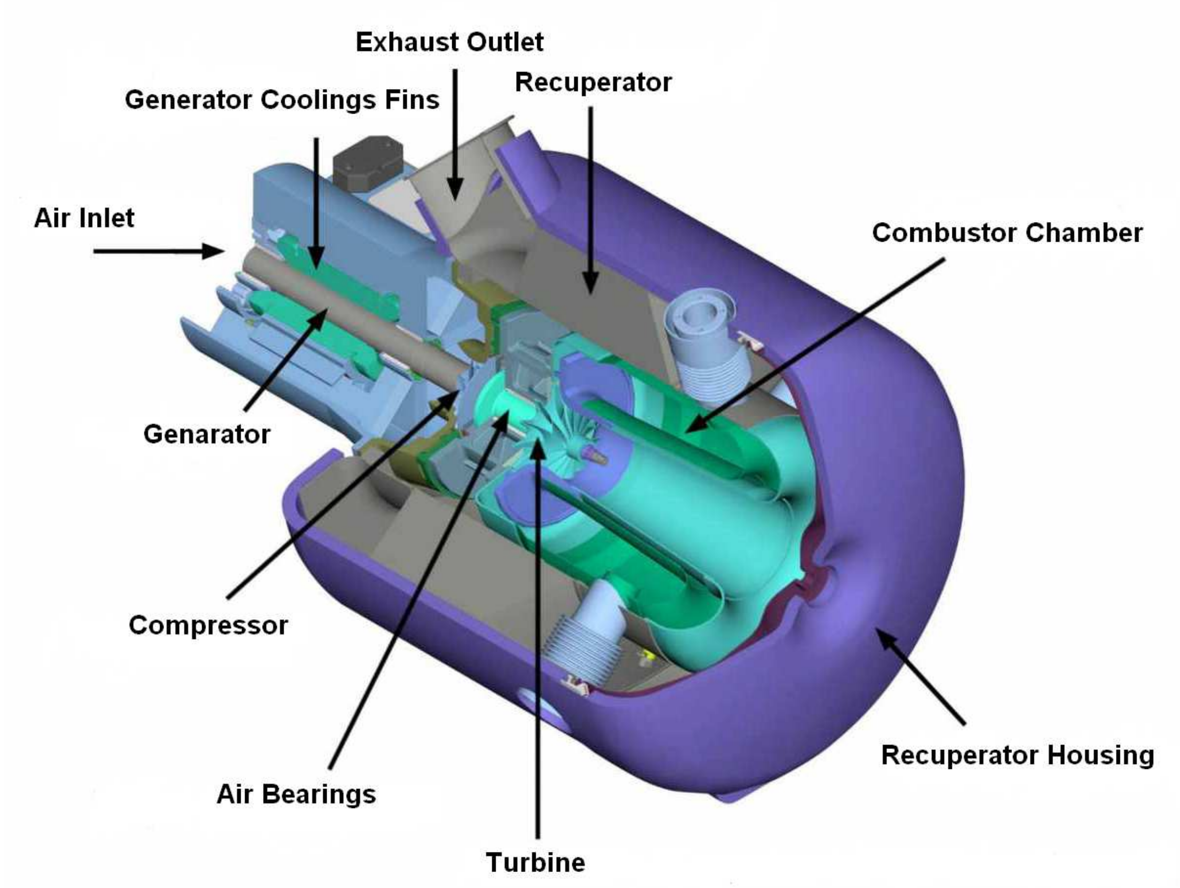


Figure17. Cross section of a Capstone microturbine.
Source: [32].

Microturbines have relatively low electric efficiencies, even with a recuperator electric efficiencies are typically 20 - 32 %, with overall CHP efficiencies of 50 - 80 %. Microturbines can be successfully fired on landfill gas but with careful consideration given to the way that the gas is handled and treated. Microturbine can run on landfill gas with methane content as low as 30 % [26].

Microturbines can be used for power generation and also in combined heat and power (CHP) systems. A schematic of a microturbine-based CHP system is shown in Figure 17. In CHP applications, the waste heat from microturbine exhaust is used to produce hot water (up to 93˚C). This option can replace relatively expensive fuel, such as propane, needed to heat water in colder climates to meet space-heating requirements. The sale or use of microturbine waste heat can significantly enhance project economics [32]. Hot water can be used to heat building space, to drive absorption cooling, and to supply other thermal energy needs in a building or industrial process [31].

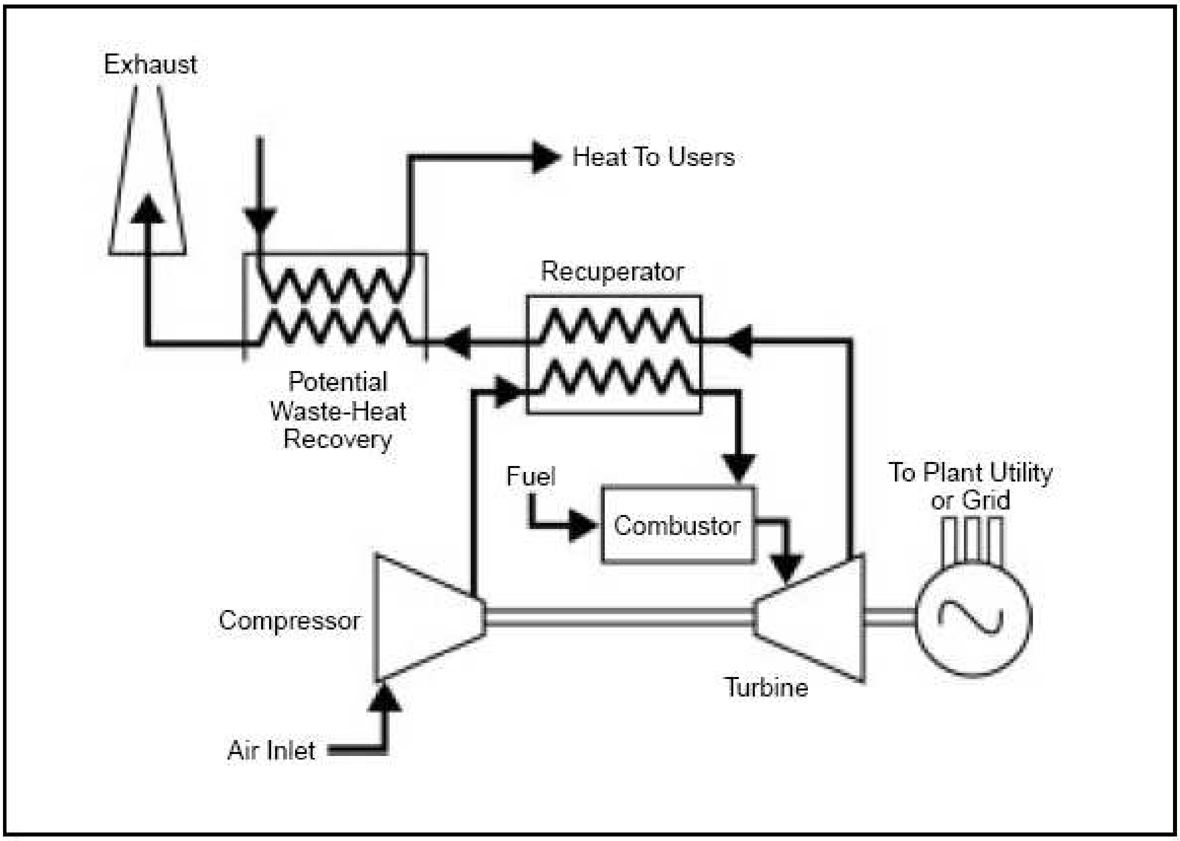


Figure 18. Microturbine CHP System.
Source: [32].

The size range for microturbines, available or in development, is from 30 to 400 kW. The sizes of the microturbines offered by the producers are as follows [31, 32]:

- Capstone (Chatsworth, California, USA) 30 kW 65 kW and 200 kW
- Ingersoll-Rand (Portsmunth, New Hampshire, England) 70 kW and 250 kW
- Turbec (Malmo, Sweden) 100 kW
- Elliott Energy Systems (Jennette, Pennsylvania,USA) 80 kW
- Bosman Power (Southampton, England) 80 kW

Microturbine heat rates are generally 4 to 4.6 kWh_H/kWh of electricity produced [32]. Table 8 and 9 provide cost estimates for CHP applications, assuming that the CHP system produces hot water for use on-site and power-only cost estimates. Equipment only and installed costs are estimated for the four typical microturbine systems. Of course installed costs can vary significantly depending on the scope of the plant equipment, geographical area, competitive market conditions, special site requirements, emissions control requirement, prevailing labour rates, and whether the system is a new or retrofit application. The basic microturbine package consists of the turbogenerator package and power electronics. Installed costs based on CHP system producing hot water from exhaust heat recovery. The 70 kW, 100 kW and 350 kW systems are integrated with heat recovery heat exchanger built into the equipment. The 30 kW unit is built as electric-only generator and the heat recovery heat exchanger is a separate unit [26].

Table 8. Estimated cost for Microturbine Generators in CHP Application.

Nominal Capacity (kW)	**30**	**70**	**100**	**350**
	Costs (USD/kW)			
Equipment				
Microturbine	1,000	1,030	800	750
Gas Booster Compressor	incl.	incl.	incl.	incl.
Heat Recovery	225	incl.	incl.	incl.
Controls/Monitoring	179	143	120	57
Total equipment	**1,403**	**1,173**	**920**	**807**
Labour/Materials	429	286	200	160
Total Process Capital	1,832	1,459	1,120	967
Project and Construction Management	418	336	260	226
Engineering and Fees	154	146	112	86
Project Contingency	72	58	45	38
Project Financing (investment during construction)	40	32	25	21
Total Plant Cost (USD/kW)	**2,516**	**2,031**	**1,561**	**1,339**

Source: [26].

Since heat recovery is not required for systems that are power-only, the capital costs are lower.

Table 9. Estimated cost for Microturbine Generators in Power-only Application.

Nominal Capacity (kW)	**30**	**70**	**100**	**350**
	Costs (USD/kW)			
Equipment				
Microturbine	1,000	980	750	700
Gas Booster Compressor	0	0	0	0
Heat Recovery	0	0	0	0
Controls/Monitoring	179	143	120	57
Total equipment	**1,179**	**1,123**	**870**	**757**
Labour/Materials	300	200	140	112
Total Process Capital	1,479	1,323	1,010	869
Project and Construction Management	266	245	188	206
Engineering and Fees	130	85	64	44
Project Contingency	56	50	38	34
Project Financing (investment during construction)	31	27	21	18
Total Plant Cost (USD/kW)	**1,962**	**1,729**	**1,320**	**1,171**

Source: [26].

Microturbines are still on a learning curve in terms of maintenance, as initial commercial units have seen only two to three years of service so far. Non-fuel operation and maintenance costs are about 1,5 to 3 cents per kWh.

A gas microturbine overhaul is needed every 20,000 to 40,000 hours depending on manufacturer, design, and service. A typical overhaul consists of replacing the main shaft with the compressor and turbine attached, and inspecting and if necessary replacing the combustor [26].

A good example of a microturbine project is a H.O.D. landfill in Lake County near Antioch, Illinois, which currently supplies heat and electricity to the school. The closed 20 ha municipal and industrial solid waste disposal facility was operated from 1963 to 1984. During that time, the landfill accepted approximately 2 million tons of waste.

From 2002, after receiving approval from all parties involved, construction of an energy system to use the H.O.D. Landfill's gas to produce electricity and heat for the Antioch Community High School began.

Landfill gas is piping from the landfill site to 12 Capstone MicroTurbines located on the school property (2,4 km). Each Capstone MicroTurbine generates 30 kW of electricity for a combined total of 360 kW. Each microturbine also produces exhaust energy of 85 kWh at 290˚C. The exhaust from the microturbines is routed through a waste heat recovery system. Recovered heat is used for the school's sports complex and swimming pool. At times when waste heat recovery is not required by the Antioch Community High School, the exhaust is automatically diverted around the exchanger, allowing for continued electrical output [34, 33].

Picture 17. Microturbines in the methane co-cogeneration plant in Antioch Community High School
Source: [33]

Another example is Lopez Canyon Landfill in Lake View Terrace in California - the world's largest LFG microturbine installation which runs exclusively on methane gas produced by landfill.

The USD 4 million project was initiated by the Los Angeles Department of Water and Power and the South Coast Air Quality Management District. Each of the 50 microturbines, developed by Capstone MicroTurbines, is producing 30 kW of electricity. Approximately 1,3 MW of power can be generated for export into local utility grid, which is enough power to serve 1500 homes in the Los Angeles area (net of about 300 kW used onsite). The installation at Lopez Canyon also eliminates approximately 10000 pounds of NO_x emissions per year, the equivalent to removing 500 automobiles. The Capstone units at Lopez Canyon are a version of the Capstone C30 especially configured to run on landfill [35, 36].

Picture 18. Microturbines at Lopez Canyon Landfill.
Source: [36]

2.2.4 Stirling Engines

Traditional gas or diesel internal-combustion engines mix fuel and air inside the cylinder. The mixture is ignited causing the combustion that pushes against the piston. The Stirling engine works differently. It contains a working gas (which may be air or an inert gas such as helium or hydrogen) that is sealed inside the engine and is used over and over. Rather than burning fuel inside the cylinder, the Stirling engine uses external heat to expand the gas contained inside the cylinder. As it expands, the gas pushes against the piston. The Stirling engine then recycles the captive working gas by cooling and compressing it, then reheating it again to expand and drive the pistons which, in turn, drive a generator and produce electricity [37].

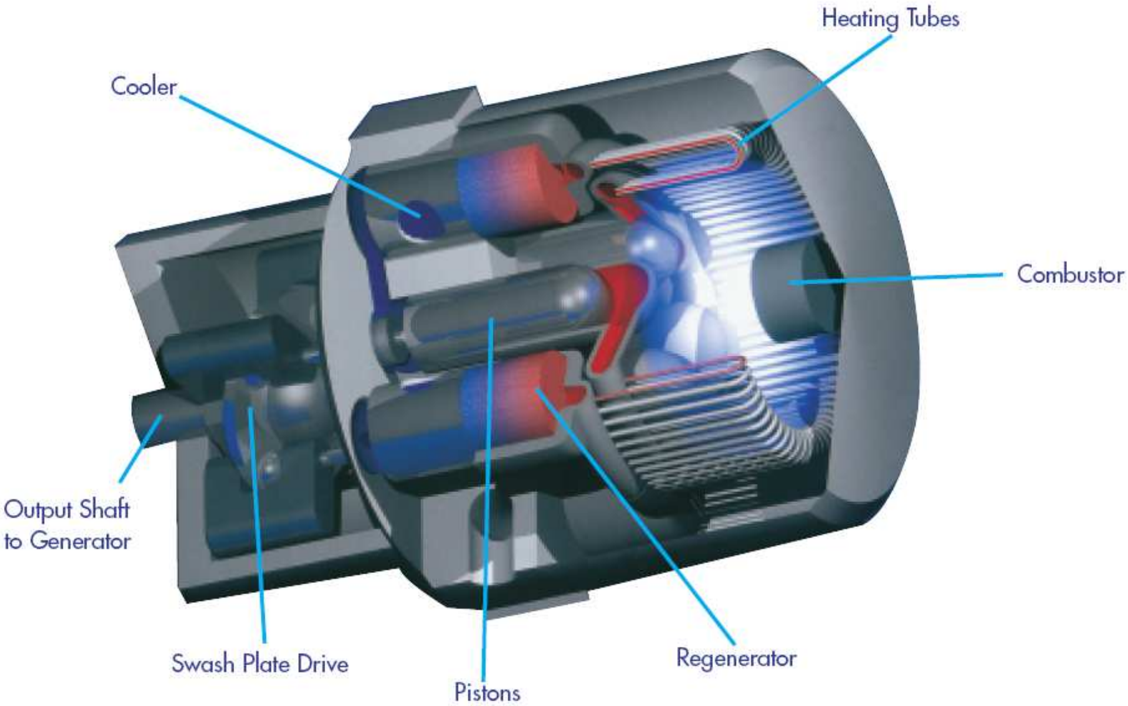


Figure 19. STM 4-Piston Stirling engine.
Source: [38].

STM's 4- Piston engine (Figure 19) relies on a single piston per cylinder design. Each of the pistons in the four-cylinder engine is double-acting, providing both displacement and power. The upper portion of the piston receives the heat from the external combustion process, which increases the pressure of the working gas. By releasing the volume, the gas expands, moving the piston. As the gas expands, it is cooled in the lower portion of the piston, facilitating compression of the working gas and completing the cycle.

The STM 4- Piston engine operates at heater head temperatures of 700 – 800 ˚C, with a water/glycol cooling medium temperature of 50 – 70 ˚C, resulting in a net electrical efficiency of almost 30 % [39].

Stirling engine burners have a high tolerance for siloxanes and other particulates, so gas pretreatment may not be necessary.

Sterling engine can be operated in the CHP mode (but only hot water), in which waste heat produced as a byproduct of the electrical generation process is recovered and utilized. In STM engine heat is removed from the engine's combustion process using a water cooling system.

Water is directed through an internal cooling loop at a temperature of 60 ˚C and then runs through a heat exchanger. If the heat recovery is not required, a radiator is available to cool the engine. Electrical efficiency of the power units is 30% with 80% efficiency in the total CHP system. Recovered heat in the form of hot water can be used for space heating or in commercial or industrial processes.

Picture 19. STM CHP unit.
Source: [38]

To date, few organizations have produced trial Stirling engines using exhaust from fossil fuel combustors. Those that have been produced are designed to generate less than 200 kW of power, and none of these are commercially available. All recent research related to Stirling engines has been focused on small-sized engines, from less than 2,5 kW (Sunpower, Inc.) to about 100 kW (MTI's ASE engine, Stirling Thermal Motors now STM Power) and more technology-focused companies including Tamin Enterprises, Stirling Technology Co., Whispertech, United Stirling and Stirling Energy Systems. Mechanical Technology Incorporated (MTI) is currently developing a Stirling engine called the Mod III, which could be adapted to use LFG. Currently, no research is underway to develop a larger Stirling engine that could be used in an LFG application (greater than 300 kW).
No cost estimates were developed for this report because Stirling Cycle engines are in a conceptual and experimental phase of development for small power output (e.g., 200 kW). Cost predictions at this point would be speculative.
Since January 2003, the first successful demonstrations of 2 - 25 kW and 8 - 25 kW Stirling-Cycle engines using landfill gas are operational at two landfills in Michigan. Project costs are

USD 1,200 – USD 1,500 per kW (installation not included), with maintenance at around 1 cent per kWh.

Picture 20. 50 kW installation at a landfill in Michigan.
Source: [38]

Picture 21. 200 kW installation at a landfill in Michigan.
Source: [38]

2.3 Biomethane Production

Biomethane is a gaseous fuel with physicochemical properties similar to those of natural gas, which makes it possible to inject it into the gas grid. LFG can be upgraded to biomethane by removing carbon dioxide (CO_2) and trace contaminants, such as ammonia (NH_3), hydrogen sulphide (H_2S), siloxanes, etc.

To following technologies for CO_2 removal from landfill gas are employed to improve the energy value of the fuel:

- Pressure Swing Adsorption (PSA),
- Physical and chemical absorption,
- Membrane separation,
- Cryogenic treatment.

The processes are different not only in terms of the utilized technique, but also in terms of the achievable gas quality, the processing behaviour, and the experience with which they have been used in landfill gas processing. An overview of these processing methods is shown in the table 11.

Table 11. Overview of CO_2 removal processes.

Separation Method	**Process**	**Functioning Principle**	**Final Methane Content**
Adsorption	Pressure Swing Adsorption	Adsorption of CO_2 a molecular sieve	> 96 Vol.-%
Physical absorption	Pressurized Water Wash	Dissolution of CO_2 in water at high pressure	> 96 Vol.-%
	Selexol®-, Rectisol®-, Purisol®- Processes	Dissolution of CO_2 in a specialized solvent	> 96 Vol.-%
Chemical absorption	Monoethanolamine (MEA) - Wash	Chemical reaction of CO_2 with MEA	> 99 Vol.-%
Membrane separation	Polymer membrane gas separation (dry)	Membrane permeability of H_2S and CO_2 is higher than CH_4	> 80 Vol.-%
	Membrane gas separation (wet)		> 96 Vol.-%
Cryogenic process	Low temperature process	Phase transformation of CO_2 to liquid, while CH_4 remains gaseous	> 99,9 Vol.-%

Source: [40].

2.3.1 Pressure Swing Adsorption (PSA)

One of the most widely used adsorption techniques is the Pressure Swing Adsorption (PSA), a classic cyclical process relying on porous materials (molecular sieves) for short-lasting pressure adsorption of selected gases, which are then desorbed in a pressure-relief phase.

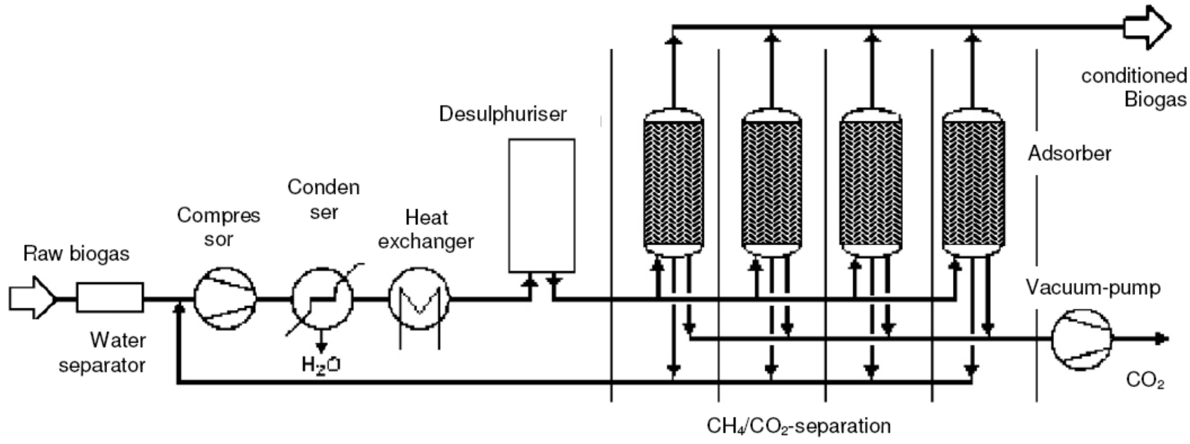


Figure 20. CO_2 removal from LFG using the PSA method.
Source: [41].

A PSA plant comprises four identical cylinder-shaped vessels filled with activated carbon granules, which are called molecular sieves. Owing to their characteristics, molecular sieves can selectively adsorb to their surface different gases (CO_2, N_2, O_2, H_2O and H_2S), as a result of which the mixture of gases is separated and the gas stream coming out of the vessel contains essentially only methane. The process takes place at pressures of 8 – 10 bar. When the adsorbent bed in a given vessel reaches the end of its capacity, it is disconnected from the plant and the molecular sieves are regenerated through a pressure reduction and purge cycle. Using four identical adsorbent vessels enables continuous production of the target gas – one unit selectively adsorbs gas impurities under pressure and produces pure methane, the second one desorbs the separated impurities at reduced pressure, the third one is purged with hot pure methane, while the fourth one is cooled with pure CH_4 and prepared for the pressure-driven part of the PSA process.

Thus far, PSA has been the most economically viable method of landfill methane separation [41]. Currently, more and more often a combination of two technologies is used to elevate methane concentrations in biomethane.

2.3.2 Membrane Separation

The process of gas separation using solid membranes relies on differences in physicochemical and chemical interactions between the individual components of a gas mixture and the membrane material. The phenomenon is caused by the difference between the rates at which gas components permeate the membrane. One of the gas constituents dissolves in the membrane material and diffuses through the membrane. Thus, the membrane separates gases into residue and permeate streams. Gas absorption membranes are microporous solids used to transport one of the gas constituents to the liquid absorbent.

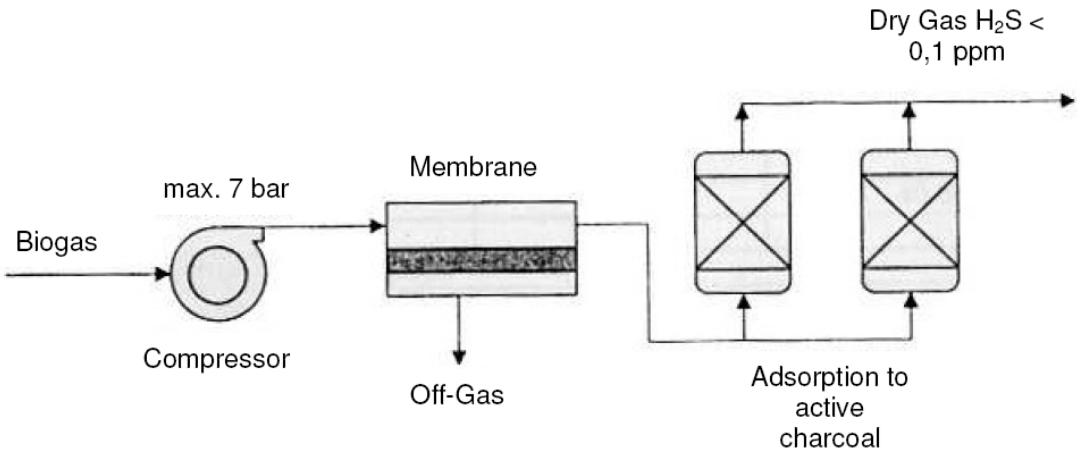


Figure 21. Process schematic for the cleaning of LFG with membrane technology.
Source: [41].

The separation is the result of the presence of liquid absorbent on the one side of the membrane, which selectively removes certain components from the gas stream circulating on the other side. The solubility of carbon dioxide is nearly twenty times that of methane, due to the molecular structure of the two compounds. Carbon dioxide passes through the membrane and dissolves in the liquid absorbent, e.g. monoethylamine. Currently various membrane types are available, including porous inorganic, palladium, polymer and zeolite membranes. As single-membrane systems achieve low degree of separation, multi-step systems are commonly employed. In the case of CO_2 capture, two types of membrane systems are used: gas separation membranes (made of ceramic and polymer materials) and gas absorption membranes. The downsides of a multi-membrane system include high methane losses. In the membrane-based CO_2 separation process, CO_2 is obtained in the gaseous form.

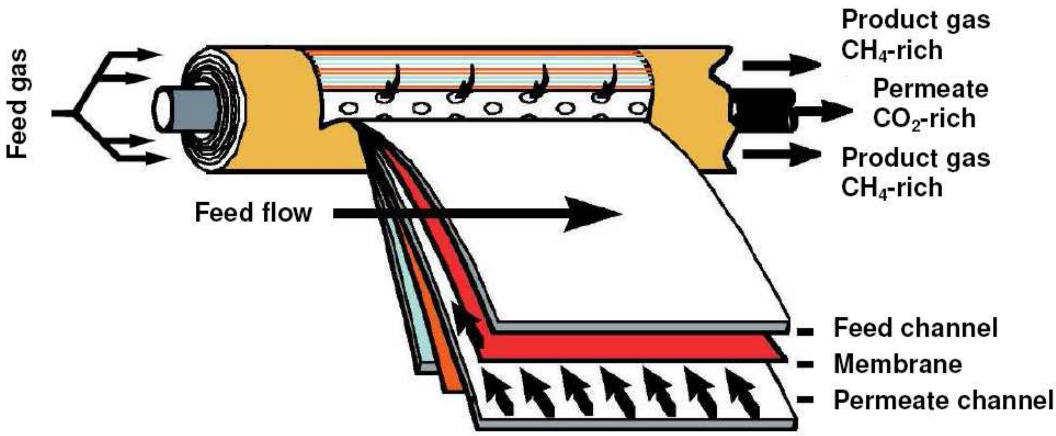


Figure 22. Spiral winding module for gas separation using gas permeation.
Source: [41].

Table 12 compares the various methods of LFG upgrading to biomethane, with a particular focus on the working pressures and losses of methane released during desorption.

Table 12. Methods of LFG upgrading to biomethane.

Method	Process	Working pressure (bar)	Methane losses (%)
Adsorption	Pressure Swing Adsorption	6-10	< 2
Absorption	Pressurized Water Wash	10	< 2
	Selexol Process	7-10	< 6,5
Chemical absorption	Monoethanolamine (MEA)- Wash	atmospheric	< 0,1
Membrane separation	Membrane gas separation	25-40	< 3

Source: [41, 42].

Examples of successful biomethane projects

Iris Glen. At the Iris Glen Landfill in Tennessee, LFG is converted to High Heating ValueLFG through the use of membrane separation technology. The treated LFG is transported approximately 8 kilometres to a hospital complex for use in its boilers. At this project, the LFG is processed to achieve at least 80 % methane. While this concentration of methane does not achieve pipeline-grade natural gas levels, it facilitated use in the boilers without having to have the boilers retrofitted.

Injection of upgraded landfill gas into the gas grid of Hardenberg- The Netherlands. On the landfill site “Collendoorn” in Hardenberg, located in the east of the Netherlands, landfill gas is being upgraded to natural gas quality and introduced into the gas grid. In 2006 around 200,000 Nm^3 of upgraded gas were produced. It used to be over 700,000 Nm^3/year in the early years of the upgrading plant, but volume of gas from the landfill has decrease. Gas upgrading is performed by membrane technology. In the first which was started in 1993, membranes operated with a gas pressure of 35 bar. Since 2003 new membrane separation technology has been used enabling the gas pressure to be lowered to 9 bar. This has reduced costs and improved the economic feasibility of the plant. The upgraded gas has a methane content of 88%, a CO_2 content of almost 5% and N_2 content of 7% [42].

2.4 Advantages and Disadvantages of the Different Technologies

The goal of a landfill gas (LFG) energy project is to convert LFG into a useful energy form, such as electricity, steam, heat, or pipeline-quality gas. Table 13 shows a summary of the different LFG energy technologies discussed in chapter 2. The table presents key advantages and disadvantages associated to each technology. It also shows the amount of LFG flow usually associated with each technology [7].

Table 13. Summary of LFG Energy Technologies.

Technology	**Advantages**	**Disadvantages**	**LFG Flow Range for Typical Projects (Methane content 50%)**
Boiler, dryer and process heater	Can utilize maximum amount of recovered gas flow. Limited condensate removal and filtration treatment is required. Gas can be blended with other fuels.	Need to retrofit equipment or improve quality of gas. Cost is tied to length of pipeline; energy user must be nearby (pipelines up to 30 km). Need large landfill size. End use facility may require boiler retrofits which can be	Utilizes all available recovered gas.

		expensive.	
Infrared heater	Limited condensate removal and filtration treatment is required. Relatively inexpensive. Easy to install. Does not require large amount of gas. Can be coupled with another energy project. Reasonable payback. Low sophistication - simple to operate. Simple controls. Construction short time.	Seasonal use may limit LFG utilization.	Small quantities of gas
Leachate evaporation	Good option for landfill where leachate disposal is expensive. Proven technology that meets local air quality requirements. For landfills with limited leachate treatment options and high leachate disposal costs.	High capital costs. More expensive than traditional landfill leachate treatment options. Generally for larger landfills.	0,53 m^3/h is necessary to treat 1 litre leachate
Internal combustion engine	High efficiency compared to gas turbines and microturbines. Good size match with the gas output of many landfills. Relatively low cost on a per kW installed capacity basis when compared to gas turbines and microturbines. Efficiency increases when waste heat is recovered. Can add/remove engines to follow gas recovery trends.	Relatively high maintenance costs. Relatively high air emissions.	30 to 2000 m^3/h per engine; multiple engines can be combined for larger projects
Gas Turbine	Economies of scale, since the cost of kW generating capacity drops as gas turbine size increases and the efficiency improves as well. Efficiency increases when heat is recovered. More resistant to corrosion	Efficiencies drop when the unit is running at partial load. Require high gas compression. High parasitic loads. Capacity and efficiency depend on ambient factors, chiefly temperature. Relatively low electrical efficiency.	Exceeds minimum of 2,200 m^3/h; typically exceeds 3,600 m^3/h

	damage. Low nitrogen oxides emissions. Relatively compact. High operating flexibility, short start-up time. Good reliability and availability. Heat at high temperature can generate good quality steam. Small size and good capacity to weight ratio. External cooling not required.	Relatively high pressure of gas fed to combustion units. Acoustic shields required. Efficiencies drop when the unit is running at partial load.	
Microturbine	Need lower gas flow. Low nitrogen oxides emissions. Relatively easy interconnection. Ability to add and remove units as available gas quantity changes. Very low air emissions. Microturbines burn cleaner than reciprocating engines. Ability to produce heat and hot water. Microturbines manufacturers offer a hot water generator to generate hot water (up to 93 ˚C) as a standard option. Ability to burn lower methane content LFG. Microturbines can run on LFG with 35% methane content and as low as 30 %. Fewer moving parts, compact construction, easily sized, require minimal operation and maintenance. Ability to move microturbines to another project site when gas quantity changes.	Require fairly extensive pretreatment of LFG. Lower efficiency than reciprocating engines and other type of turbines, microturbines required more fuel per kWh. LFG treatment to remove moisture, siloxanes, and other contaminants is required for microturbines and sensitive to siloxane contamination, microturbines required more pretreatment than LFG used to power turbines or other engines. Limited experience. Little information about the long-term reliability and operation and maintenance costs of LFG microtubines.	30 to 340 m^3/h
Sterling Engines	Working gas sealed inside a vessel. Low emissions. Quiet and low vibration. Internal parts not in contact	The Stirling engine is larger than an internal combustion engine for the same output the cost of a Stirling engine per kW is higher than that of the less	

	with contaminants from LFG fuel. Stirling engine can be equipped with low cost integral heat exchangers for combined heat and power (CHP) applications. It has a 30% electrical efficiency and 80% total system efficiency in CHP applications. Low maintenance costs- requires very little fuel treatment and generally requires maintenance only once a year in full-time operation. Do not require costly fuel compressors.	efficient internal combustion engine. Not commercially available. High capital cost. Not a proven technology.	
Biomethane production	Can be sold into a natural gas pipeline. Membrane separation. Easy to construct. Simple to operate. Pressure Swing Adsorption (PSA): • No operating material necessary except process water, chemicals, etc. • Many reference systems in Europe.	Requires potentially expensive gas processing. Increased cost due to tight management of wellfield operation needed to limit oxygen and nitrogen intrusion into LFG. Membrane separation: High methane losses Short life of membranes (approx. 3 years) Need to ensure high pressure. Pressure Swing Adsorption (PSA): • High pressure is necessary (means high energy consumption). • System must be able to operate safety at high pressure (high cost). • Relatively high methane losses.	1,000 m^3/h and up, based on currently operation projects

Source: [7].

3. Choice of Technology

Landfill-gas-to-energy projects involving generation of heat, power (or cogeneration of heat and power – CHP) need to be carefully assessed in terms of expected energy output and project economics, taking into account the time factor. In practice, an assessment of utilisation options for landfill gas forms part of a project feasibility study, which includes three key elements:

- landfill gas modeling;
- confirmation of the gas modeling – pump tests;
- evaluation of the economics of several alternative technology choices.

3.1 Landfill Gas Modeling

The methodologies used to project gas generation of municipal waste landfills are discussed in detail in Section 1.1. above. In the context of selecting the best technology for an LFG project, it should be stressed that the gas generation of municipal solid waste landfills changes over time, which directly affects the amount of chemical energy (gas flow) which can be recovered and converted into useful forms of energy. Knowledge of changes occurring within a municipal waste disposal site is key to choosing the right technology for an LFG energy project.

3.2 Confirmation of Landfill Gas Modeling – Pump Tests

Gas generation projections are based on a set of underlying assumptions, which may differ from the actual site conditions. The projections reflect only the potential capacity of a landfill to generate a specific amount of gas in specific conditions. Thus, the amount of gas estimated by a given model will not be equal to the actual gas flows.

The calculations are confirmed using a method designed to estimate landfill gas production based on flow measurements in test wells installed in dispersed locations across the entire landfill or in selected sections of the landfill. A pump test is designed to measure the rate of flow from the well, while determining the LFG composition and pressure. The most reliable results are obtained if a pump test is performed in conditions as similar to the operating conditions of the wellfield facilities as possible. The accuracy of the gas recovery estimation depends on two main factors:

- proper spacing of test wells to accurately capture the differences in the gas generation rates of the various sections of the landfill;
- precision of the measurements aimed at estimating the radius of influence of the wells.

Vacuum pump tests are designed to determine the optimum gas flow rate from the landfill in steady state conditions. A pump test should be performed under the following conditions:

- levels of oxygen in extracted gas should not exceed 1.0%,
- levels of methane may not be lower than 10% of the levels measured during spontaneous flow from extraction well.

Determination of the optimum gas flow rate may be fairly complicated, depending on the physicochemical conditions of the waste disposal site, the waste composition and the design of the wellfield facilities.

A properly designed wellfield (provided it is operated by experienced staff) enables the recovery of some 60% – 70% of the calculated and confirmed gas flow rate.

3.3 Economics

Economic feasibility is a crucial element that needs to be taken into account when determining a project’s overall feasibility, starting from a preliminary assessment of investment opportunities, to preliminary choices, to the final project [30].

The evaluation of a project’s economics should include the following key steps:

- estimation and valuation of the installed capital costs;
- estimation and valuation of products (or services) to be generated by the project;
- estimation of future net financial benefits.

The economic evaluation of a project needs to find out if a given option, while technically feasible, is equally viable in economic terms, taking into account a number of actual macroeconomic, social and environmental factors. It is performed to show if the future net financial outcome of the project will be sufficient and competitive in relation to returns on other investment opportunities offered by the capital market [30].

Investment decisions are largely made on the basis of expected positive returns (profit). However, that criterion alone may not be sufficient, since profit – as a purely economic measure – does not account for the following elements inherent in investment projects and in subsequent business activities:

- impact of risk,
- impact of time [30].

Risk is an inherent part of any business activity, largely as a factor difficult to foresee and quantify. Nevertheless, it should be factored into the economic evaluation of a project, by appropriately adjusting the minimum rate of return on the investment. At the same time, it should be noted that investments delivering high rates of return usually carry the greatest risk.

Time is a vital factor in the context of the time value of money, mainly as a result of inflation. Irrespective of inflation, the value of capital depends on the point in time when the capital is made available to the investor – the later the investor gets hold of the capital, the shorter the time in which the capital is employed, as well as its present value. Moreover, the later the investor starts to incur costs and the sooner it starts to earn revenue, the better the expected economic performance of the project. The alternative technology scenarios may differ not only in terms of the amount of capital costs required but also the distribution of such costs over time [30].

3.3.1 Cash Flows

Cash flows (CF) are a basic tool used to evaluate the economic feasibility of any business venture. Cash flows reflect a difference between cash inflows and outflows throughout the lifetime of an evaluated project.

In order to calculate cash flows, it is necessary to identify all items of project revenues and expenses in all the successive financial years, i.e. in the investment stage and the production stage. Calculations are usually made on a year by year basis. Then, the annual cash flows (CF_t) are summed up to arrive at the cash flows for all the N years covered by the evaluation. Cash flows for the entire period of project development and operation are estimated based on the following general formula:

$$CF = J_0 + J_k + S_n - K - F - R - P_d + L$$

where:

J_0 – total installed capital cost,

J_k – borrowed funds,

S_n – net value of products sold (net revenue), i.e. net of VAT,

K – total cost of products sold,

F – finance charges, i.e. interest on loan repayments,

P_d – income tax,

R – loan repayment,

L – break-up value of the business.

The total cost of products sold K is usually one of the main items of cash flows. In accounting terms, the cost of products sold K includes the items used to determine the tax base:

$$K = K_e + K_{op} + F + A$$

where:

K_e – cost of project operation,

K_{op} – general and administrative expenses, operating expenses,

A – depreciation charges [30].

Capital Costs J_o

J_o represents the aggregated capital costs incurred during the project development. If the development stage is short (up to one year), J_0 is a straightforward sum of the costs incurred. However, if the project development takes longer than one year, the costs incurred need to be discounted to their present value as at the time of project completion, i.e. year zero [30].

Cost of Products Sold K

The cost of products sold represents one of the most important items of cash flows, as in most cases its reduction is the only chance to maximise profit. Moreover, the criterion of minimum cost of production sold (at constant production rates) determines the choice of the optimum investment scenario.

Two of the above components of the total cost – cost of project operation K_e and depreciation charges A – need to be discussed in more detail.

Cost of Project Operation K_e.

The cost of project operation includes the following key items:

$$K_e = K_E + K_m + K_p + K_{rem} + K_{śr}$$

where:

K_E – cost of energy,

K_m – cost of raw materials and other inputs,

K_p – cost of labour,

K_{rem} – cost of operation & maintenance,

$K_{śr}$ – environmental charges (e.g. for air emissions, wastewater discharge, waste disposal, etc.) [30].

Depreciation

During its operation, every piece of equipment (fixed asset) is subject to gradual wear and tear as well as economic depreciation (technological outdating or obsolescence). Depreciation of a piece of equipment entails a decline in its value. Depreciation is the process of accumulating funds to cover the cost of replacing the asset after it is withdrawn from service [30].

Net Value of Products Sold (Net Revenue) S_n

The value of sales S_n is calculated as sales revenue net of VAT paid (net value of sales).

In the case of the most frequent LFG projects in Poland, i.e. electricity generation projects, two sources of revenue may be identified:

- revenue from sales of electricity;

  The Polish law requires power utilities to purchase electricity from renewable energy sources [43]. In most cases, the price of electricity sold is determined by the President of the Energy Regulatory Office [44].

- revenue from sales of energy certificates (“green certificates”).

  A Polish producer of electricity from renewable energy sources may receive additional support in the form of Energy Certificates. Under the Energy Certification System, electricity producers obtain energy certificates (“green certificates”), which may be subsequently sold on electricity exchanges. Energy certificates are obtained on the basis of electricity output.

3.3.2. Methods Used to Evaluate Profitability of Landfill Gas-to-Energy Projects

Dynamic analyses – accounting for changes in the time value of money.

The key advantage of discount methods is the fact that they capture the distribution of cash flows over time. However, what is an advantage may also pose a major practical difficulty, as discount methods require the estimation of cash flows over the entire time span of the analysis. If they relate to longer periods, such estimates will obviously involve considerable uncertainty. One could rely on a trend analysis, but even highly industrialised and established economies are occasionally subject to unforeseeable social and economic events, which may drastically change the market price structure.

Following a preliminary profitability evaluation, the following assumptions are usually adopted:

- costs and revenues are estimated on the basis of time-zero data;
- all the economic effects are discounted to year (time) zero (t=0);
- financial expenses incurred in the years preceding year zero (t<0) are discounted to level zero;
- the project becomes fully operational in the first year of operation;
- all loans contracted in the financial market are fixed-rate loans;
- the time span covered by the analysis is counted in full years.

It should be noted that some of the above simplifications may be omitted if – at the time when an analysis is performed – there are reliable grounds to factor future economic events into the calculations.

Frequently included in the calculations are price and cost escalation rates, reflecting the projected changes of selected prices in relation to assumed inflation. It should also be remembered that in the case of long-term analyses, the margin of error is, predictably, quite large [30].

NPV (Net Present Value)

Net Present Value (NPV) is understood as the value of all project-related cash expenses and revenues, incurred or earned over the lifetime of the project, discounted as at the project start year. A project is economically viable if NPV > 0 and is as high as possible.

Net Present Value may be presented as follows:

$$NPV = \sum CF_t \cdot a = \sum CF_t \cdot \frac{1}{(1+r)^t} = \sum \frac{CF_t}{(1+r)^t}$$

where:

NPV – Net Present Value **–** the sum of discounted cash flows;

CF_t – cash flow in year *t*,:

t – a given year in the project’s lifetime,

a – discount factor, which discounts (brings) the future value of money to the equivalent present value, expressed by the following formula:

$$a = \frac{1}{(1+r)^t}$$

r – discount rate, in most cases corresponding to the interest rate on one-year bank deposits [30].

IRR (Internal Rate of Return)

Internal Rate of Return (IRR) is a discount rate at which the present value of cash inflows (project revenues) is equal to the present value of cash outflows related to the project construction and operation. IRR is expressed as a percentage and corresponds to the time it takes to recover the initial investment (payback).

In other words, IRR represents a discount rate at which NPV equals 0. IRR can be calculated using the following formula:

$$\sum_{i=1}^{n} (CF_t \cdot \frac{1}{(1+IRR)^t}) = 0$$

where:

CF_t – the difference between inflows and outflows in year *t*,

n – number of years.

In order to calculate IRR, it is necessary to continue calculating NPV at different discount rates until one achieves NPV close to 0. Excel spreadsheets include an embedded IRR function (the problem is addressed using the iterative approach).

If we know two discount rate values r_1 and r_2 such that the r_1 value gives NPV close to 0 but positive (designated as NPV_1) and the r_2 value gives NPV close to zero but negative (designated as NPV_2), we can calculate an approximate IRR using the following formula:

$$IRR = r_1 + [(r_2 - r_1) \cdot (\frac{NPV_1}{NPV_1 - NPV_2})]$$

where:

r_1 – discount rate which gives a positive NPV;

r_2 - discount rate which gives a negative NPV [45].

4. Project Development Options

Once the decision is made to initiate an LFG energy project, the next step is to determine who develops, manages, and operates the project. Two primary models can be followed in structuring the development, ownership, and operation of an LFG energy project:

- A landfill owner/operator can self-develop the project and operate the LFG energy project with landfill personnel. The landfill owner directly hires individual consultants and contractors to fulfil each role that the landfill personnel cannot perform themselves.
- An outside project developer can finance, construct, own, and operate the LFG energy project [7].

There are also hybrid approaches to developing an LFG energy project, but they all draw on the same principles presented in this chapter.

In any case, the landfill, energy end user, and LFG energy project owner will need assistance from outside partners. These partners typically are consulting engineers, lawyers, contractors, regulatory and planning agencies, community members, and financial professionals. The involvement of multiple partners helps to ensure timely development of an LFG energy project that is financially feasible and benefits the environment and the local community.

In deciding whether to seek a project developer, the landfill owner should consider economics, technical expertise available to the landfill, and the level of risk the landfill is willing to accept [7].

Economics.

Significant capital (upfront) costs are required to design, build, and operate an LFG energy project. In order to determine if the landfill owner has enough capital available, an economic feasibility study is prepared as described in chapter 3. Results of this study are evaluated for capital needs, internal rates of return (IRR), and other financial needs. The landfill owner considers available capital and financing options (e.g., private financing or municipal bonds) to determine if sufficient funding is available or can be obtained. If the landfill chooses to hire a developer, the developer would obtain the funding [7].

Expertise.

To develop an LFG energy project, landfill owners will need to interact with partners who have a variety of specialized technical, financial, or legal expertise. One way to improve this interaction is to use a qualified project manager (PM). A qualified PM knows the landfill owner's operating and financial constraints, has the expertise and authority to direct work on the project, and must be able to make a significant time commitment to managing the project for a long period (often up to two years).

Landfill owners might need to seek the expertise of consultants and contractors to design, build, and/or operate these LFG energy projects, especially if they plan to self-develop. A *consultant* can give landfill owners technical assistance on the design and technical recommendations regarding state and federal regulations and operation of the wellfield and energy project. *Contractors* can provide advice on how to build the LFG energy project, but their main responsibility is construction of the facility. After construction, a contractor, operation and maintenance (O&M) vendor, or consultant can operate the LFG energy project if the landfill owner decides not to operate the project using landfill personnel [7].

Risk Level.

The amount of risk that the landfill owner is willing to accept is an important factor in deciding whether to self-develop the LFG energy project or seek a project developer who will assume much of the risk. Risks involved in LFG energy projects include:

1. Construction:

- Cost overrun;
- Project delays;
- Failure of plant to meet performance criteria;
- Weather and seasonal implications;
- Work warrantees.

2. Equipment:
   - Mechanical failures;
   - Not meeting specifications;
   - Not meeting emission requirements;
   - Not configured for the corrosiveness of LFG.
3. Permitting:
   - Excessive permit conditions/right of way;
   - Public comments on draft permits.
4. Financial performance:
   - Not having enough LFG;
   - Maintenance downtime;
   - Operation cost overrun;
   - Project financing;
   - Labour and material costs;
   - Regulatory exposures [7].

Other Reasons to Consider Using a Project Developer or to Pursue a Hybrid Option. Selecting a developer to manage, own, finance, and operate the LFG energy project reduces risks for a landfill owner. The developer also incurs the cost associated with an LFG energy project, so there is no net cost to the landfill owner. Other reasons for selecting a project developer are:

- The project developer's skills and experience may bring a project online faster.
- The developer may have numerous other LFG energy projects, which allow them the economies of scale to reduce capital and O&M costs.
- Some developers invest equity or have access to financing.
- The developer might possess a power sales agreement that was previously won and/or negotiated with a nearby electric utility.

- Bringing on a developer can simplify the project development process for the landfill owner, requiring less landfill staff time and expertise.
- In return for accepting project risks, the project developer retains ownership and control of the energy project and receives a relatively large share of the project profits. Note that developers may make decisions that tend to favor factors that increase energy revenues but not necessarily the landfill owner's priorities, such as managing LFG migration and emissions [7].

A turnkey project allows for a hybrid approach. With turnkey projects, the landfill owner retains energy project ownership, but the project developer assumes the responsibility for construction risk, finances, and building the facility. Once the LFG energy project is built and operating to project specifications, the developer then transfers operation of the LFG energy project to the landfill owner. In return, the landfill owner gives the project developer a smaller portion of the project proceeds, gas rights, and/or a long term O&M contract. The turnkey approach can be a "win-win" approach for both the project developer and the landfill owner since the developer retains responsibility of construction, development, and performance risk and the landfill owner assumes the financial performance risk [7].

Other Reasons to Consider Self-Developing a Project.

On the other hand, there can be advantages to self-developing a project. For example, the landfill retains control and retains a larger share of the profits in return for accepting the risk. In addition, developing a project may be a rewarding challenge and opportunity for landfill staff, and such projects can foster good relationships with end users, other partners, and the community.

In summary, the project developer, self-development, and hybrid approaches have all yielded successful LFG energy projects. The key is finding the approach that is best suited to the specific landfill and other participants involved in the project [7].

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