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LANDFILL GAS ENERGY UTILIZATION: TECHNOLOGY OPTIONS AND CASE STUDIES

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LANDFILL GAS ENERGY UTILIZATION: TECHNOLOGY OPTIONS AND CASE STUDIES

Don Augenstein
John Pacey
EMCON Associates
San Jose, CA 95131

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EPA Project Officer:

Susan A. Thorneloe
Global Emissions and Control Division
Air and Energy Engineering Research Laboratory
Research Triangle Park, NC 27711

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FOREWORD

Landfill gas has been successfully used for energy at many locations in the U.S. and worldwide, providing economic, environmental, and other benefits. However, landfill gas energy uses are also relatively new, and technologies are far from "cut and dried." There are limitations and special considerations with landfill gas energy use; a number of landfill gas energy projects have experienced problems, or even failed entirely. There is current need for documentation of experience and consolidation of information in several areas regarding the use of landfill gas as a fuel.

This report reviews the various landfill gas energy uses, and their associated issues and constraints. It also presents case studies of six landfill gas energy projects in the U.S. The report's purposes include

- Presenting overviews of use and equipment options, and technical and other considerations with landfill gas energy applications.
- Providing information on projects that illustrate common landfill gas energy uses.
- Providing an awareness of limitations and potential pitfalls existing with landfill gas energy use.

In addition to providing background on energy uses, it is anticipated that the report will help identify areas needing attention, for entities such as researchers and equipment manufacturers. It is also hoped that the report can provide information useful in identifying ways to facilitate the beneficial uses of landfill gas by reducing nontechnical barriers.

The complexities of landfill gas energy uses are such that the discussions of many issues must be limited to overviews. Where detail is available elsewhere the report refers to available literature containing that information. This is also true for the case studies; these attempt to provide information so that a typical reader with some limited background will have a reasonable understanding of the operation, based on a representative description of a particular energy application. This document is not intended to provide the degree of detail needed to design and operate a landfill gas energy facility.

The case studies rely on information provided by many individual operators, equipment manufacturers, and others such as engineering firms. An effort has been made to verify statements and data as much as possible. In particular, all sections of the report have been reviewed by the providers of the original information and others with appropriate expertise. Background information is cited from literature and other sources considered reliable, and it has also been reviewed.

ABSTRACT

Combustible, methane-containing gas from refuse decomposing in landfills, or "landfill gas," can be fuel for a variety of energy applications. This report presents case studies of projects in the United States where it has been used for energy. It also presents overviews of some of the important issues regarding landfill gas energy uses, including appropriate equipment, costs and benefits, environmental concerns, and obstacles and problems of such energy uses.

With allowance for its properties, landfill gas can be used in much commercially available equipment that normally uses more conventional fuels such as pipeline natural gas. This includes equipment for space heating, boilers, process heat provision and electric power generation. Landfill gas energy uses, already significant, could increase based on estimates of the landfill gas that could be recovered, and providing that other factors, particularly economic ones, are favorable. Such energy uses have environmental and conservation benefits.

Factors to be considered in using landfill gas for energy include contaminants, which can corrode equipment and cause other problems, and its lower energy content, resulting in moderate equipment derating. Other issues that are of normal concern for landfill gas, such as forecasting its recoverable quantity over time, and its efficient collection, also bear importantly on its use for energy.

The case studies review landfill gas energy use at six sites in the U.S. The energy applications include electric power generation by reciprocating internal combustion engines, electric power generation by gas turbine, space heating, and steam generation in a large industrial boiler. Case study applications are considered to represent attractive candidate uses for implementation at additional U.S. landfill sites. The case studies present the relevant site features, background regarding the development of the case study project, equipment used, operating experience, economics, and future plans at the sites. Obstacles and problems at the sites are discussed. The case study sites exhibit wide variation in features such as cost and degree of operating difficulty experienced. Such variation is typical of landfill gas energy projects, which tend to be site specific. Literature containing information on other relevant case studies, in both the U.S. and other countries, is also referenced.

Important conclusions include

- Landfill gas can be a satisfactory fuel for a wide variety of applications. Such uses have environmental and conservation benefits. Many types of energy equipment designed for "conventional" fuels can operate on landfill gas with outputs reduced by about 5 to 20 percent.
- Allowances must be made for the unique properties of landfill gas and particularly its contaminants. Pitfalls possible in landfill gas energy applications include equipment damage due to such gas contaminants, and shortages resulting from over-estimation of its availability.
- The degree of gas cleanup and the methods used vary widely; the necessary amount of cleanup and the optimum tradeoffs between cleanup stringency and the frequency of maintenance steps (such as oil changes) are not well established.
- Cost-to-benefit ratios can vary widely; at some sites they are excellent, while at others they are a major limiting factor. Economics are probably the most important factor limiting landfill gas energy uses. Economics currently tend to preclude smaller scale uses, uses where electric power sale prices are low, and uses at remote sites lacking convenient energy applications or outlets. Much of the landfill gas generated today is not used for energy because of economics.

- Energy equipment emission limits in some U.S. locations may also restrict landfill gas energy use, despite an environmental balance sheet that generally appears to be positive.

This report identifies technical areas where energy uses are likely to benefit from improvements. Some of these are alluded to above. This report also comments briefly on incentive, barrier elimination, and other approaches that may facilitate landfill gas use. Finally, for present and future landfill gas users, further detailed documentation of the problems experienced, and the results of approaches to them (both successful and unsuccessful), would be very helpful.

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CONVERSIONS

Readers more familiar with metric units may use the following to convert to that system.

Nonmetric	Times	Yields Metric
acre	0.4047	hectares
Btu	252	Calories
ft	0.3048	meters
ft^2	0.0929	square meters
ft^3	28.32	liters
gal.	3.785	liters
hp	0.748	kilowatt
in.	2.54	centimeters
in. H_2O (head)	248.9	Pascal
in. Hg	3386	Pascal
lb. mass	0.4536	kilogram
inch	2.54	centimeter
mile	1.609	kilometer
psi	6895	Pascal
U.S. ton	0.907	metric ton

Temperature

Degrees Celsius = 0.556 (Degrees Fahrenheit - 32)

Degrees Fahrenheit = 1.8 (Degrees Celsius) + 32

1. INTRODUCTION AND BACKGROUND

This report's primary purpose is to provide information on landfill gas energy uses. The report is addressed to a range of readers, presumed to include not only those familiar with landfills, landfill gas energy, and related issues, but also some who may have relatively little familiarity with these areas.

A major report focus is case studies that document experience at representative U.S. sites where landfill gas has been used for energy. To accommodate needs of the expected range of readers, the report also presents background that should be useful to those developing knowledge of landfill gas energy uses, and helpful for understanding of the case studies. Thus, the first section of this report provides general background relating to landfills and landfill gas energy uses. This is followed in the second section by a discussion of technical issues associated with landfill gas as a fuel—including the specific characteristics of landfill gas as a fuel, and particular needs occurring with its use. The third and fourth sections of the report cover equipment issues and economics. These are followed by case studies and conclusions. It is hoped that this accommodates the needs of the anticipated range of readers.

The following section provides background primarily for the benefit of those who may have limited familiarity with solid waste landfills, landfill gas, and landfill gas energy topics. Some of the basics pertinent to the use of landfill gas as a fuel include

- what landfill gas is, and its origin
- its composition
- forecasting the quantity recoverable for fuel uses over time
- methodologies for its recovery
- environmental issues with landfill gas extraction and energy use
- regulatory demands and constraints regarding its use

These are covered below to provide a context for further discussion of energy applications in later sections. Summary discussions of certain topics are supported with more detailed information in appendices.

1.1 Landfills and Landfill Gas: General

Sanitary landfilling is the main method for disposal of municipal and household solid waste or refuse ("garbage") in the United States. With current practice at landfills (no longer called "dumps"), wastes received are spread, compacted, and covered daily with a soil cover to reduce blowing litter, manage bird and rodent activity, and control odors. The process continues over a given area until a planned waste depth is reached; wastes are then covered with a final cover that has a relatively impermeable component (often clay) to limit surface-water infiltration. Sanitary landfilling increased sharply in the U.S. in the early 1970s as open dumping and incineration were restricted. An estimated 145 million tons* of wastes are currently landfilled annually in the U.S. (Kaldjian, 1990).

Most early practitioners of sanitary landfilling apparently trusted that waste decomposition would be of minor consequence. However, even maintenance of an oxygen-free and relatively dry landfilled waste

* For readers more familiar with metric units, conversion factors are provided at the end of the front matter.

environment still permits certain biological reactions; these produce "landfill gas," and its generation can be significant.

Landfill gas consists principally of a mix of two gases: methane (chemical formula CH_4) and carbon dioxide (chemical formula CO_2). It is generated through bacterial decomposition of organic refuse in the absence of oxygen (anaerobic fermentation) (Geyer, 1972; EMCON, 1982, Gas Research Institute, 1982). It is produced by nearly all landfills in which refuse is buried such that oxygen is effectively excluded. Although many reaction steps and intermediates can be involved, the basic biochemical reaction is exemplified by the decomposition of cellulose (the principal component of paper, and a constituent of much other refuse material):

$$\underset{\text{cellulose}}{n(C_6H_{10}O_5)} + \underset{\text{water}}{nH_2O} \xrightarrow[\text{(bacteria)}]{} \underset{\text{methane}}{3nCH_4} + \underset{\text{carbon dioxide}}{3nCO_2}$$

Though this reaction scheme is simplified, it represents the overall process fairly well; most landfill gas is produced from decomposing cellulose, and most cellulose that decomposes yields methane and carbon dioxide.

Because of its methane gas component (the same methane that makes up "natural" or pipeline gas), landfill gas is a fuel. With proper allowances for its properties, landfill gas can be used for fuel in many applications where other fuels, particularly natural gas, are used. These fuel uses of landfill gas are the major focus of this report.

Landfill gas can be a significant energy resource. It is currently used at more than 100 U.S. sites (Government Advisory Associates, 1991); its use is continuing to expand. Estimates of the ultimate energy potential of U.S. landfill gas vary, but information in various references (U.S. EPA, 1991; American Gas Association, 1980) suggest recoverable energy potentials ranging between 0.2 percent to over 1 percent of the total of U.S. energy use. Though the expressed percentage of U.S. energy use might appear modest, the quantities are significant, given the total amount of energy the U.S. uses.

1.2 Composition of Landfill Gas

Characteristic composition ranges for landfill gas are shown in table 1. These are typical for "as extracted" gas as it is recovered. Also shown for comparison are the properties of "natural" or pipeline gas. As seen in table 1, landfill gas consists primarily of methane and carbon dioxide, usually in close-to-equal amounts. In contrast to pipeline gas, landfill gas also contains significant amounts of water vapor and traces of various organic compounds. Almost all of the organic compounds found in the gas (usually referred to as non-methane organic compounds [NMOCs] or sometimes reactive organic gases [ROGs]) originate through evaporation into the gas of the man-made solvents, propellants, and similar materials discarded in the refuse stream; paint solvent vapors are one of many possible examples in this category. Further discussion of these landfill gas components is presented elsewhere (Gas Research Institute, 1982; Emerson and Baker, 1991). Landfill gas as extracted can contain nitrogen and, less frequently, oxygen from air entrained as a consequence of extraction; the concentrations of these gases depend on the extraction objective and approach (Augenstein and Pacey, 1991). Landfills also contain a large amount of soil and other particulate material, and the extracted gas can pick up and carry with it a significant amount of that particulate material.

The landfill gas components other than methane have effects that are often substantial on its energy uses. Carbon dioxide, nitrogen, and (to a slight extent) water vapor can result in dilution and other effects that moderately reduce energy equipment capacity. The trace organic components (particularly the halogenated hydrocarbons) and particulates can cause serious energy equipment problems, including corrosion and accelerated wear. These effects are discussed in more detail in the next section.

TABLE 1. COMPARISON OF COMPONENT CONCENTRATIONS AND OTHER PROPERTIES:

PIPELINE ("NATURAL") GAS AND LANDFILL GAS

Component	Pipeline Gas	Landfill Gas (as extracted)
Methane, CH_4, percent	90-99	40-55
Ethane + Propane, percent	1-5	-0-
Water vapor, percent	<0.01	1-10 (typical)
CO_2, percent	0-5	35-50
Nitrogen, other inerts, percent	0-2 (typical)	0-20
Trace condensible hydrocarbons (NMOC's; ppmv as hexane)	-0-	250-3,000 (typical)
Chlorine in organic compounds (micrograms per liter)	-0-	30-300
Hydrogen sulfide (parts per million)	up to 15	to 200
Higher Heating Value, Btu/ft^3	950-1050	400-550

Information from sources including references (Gas Engineers Handbook, 1965; EMCON, 1982). Units are those most commonly used for the stated component.

1.3 Estimating the Gas Recoverable for Energy Uses

Energy users have a critical need to know the gas quantity potentially recoverable over time from a landfill for energy use. The approaches that can be used to estimate this include modeling and field extraction tests. This topic is important because misestimates of gas availability are among the common causes of problems with energy applications. For readers interested in forecasting gas availability for end uses, further discussion is presented in appendix A.

1.4 Gas Extraction Systems

The landfill gas extraction system collects gas generated by the landfilled refuse, and delivers it to the energy application. The overall concern of the gas energy user is that the system will continue to provide a reliable supply of gas in the necessary quantity. Collection efficiency may also be a concern; it depends on design and operational factors and may range between 50 and 95 percent. Further discussion of gas collection is presented in appendix B.

The topics of gas recovery systems, and extraction practice are important because difficulties with collection systems are also among the common causes of problems with energy facilities.

1.5 Environmental and Conservation Aspects of Landfill Gas Energy Use

The energy uses of landfill gas have significant environmental consequences that are considered to be predominantly beneficial. The gas extraction process helps abate both gas migration hazards and the emission of reactive organic gases that contribute to air pollution. A particular current concern is the contribution of landfill methane emissions to atmospheric methane buildup, "radiative forcing," and resulting climatic effects ("greenhouse effect"). Extraction and use mitigates these. The energy use of landfill methane also "offsets" fossil fuel use elsewhere, and reduces secondary pollution and the consequences of carbon dioxide emission that could otherwise be produced by use of that fossil fuel. Its energy use also comprises conservation. These issues are discussed elsewhere (U.S. EPA, 1991, Thorneloe and Peer, 1991; Augenstein, 1990); a further description of these issues with references to relevant literature is presented in appendix C.

1.6 Regulatory Issues

Those who become involved with using landfill gas for energy will generally be affected by many regulations that pertain to landfill gas energy use. Among the most important of these are

- Proposed federal regulations associated with the recently amended Clean Air Act. These propose limits above which NMOC/ROG emissions must be controlled, and specify the required degree of abatement. As one consequence of these regulations, most larger landfills now without energy systems, but which would be capable of supporting them, will probably be required to install gas extraction systems.
- Regulations applicable to landfill gas management, which vary locally across the U.S., and that define the performance of gas systems based on factors such as prevention of off-site migration and reduction of atmospheric NMOC/ROG emissions.
- Regulations associated with the Public Utility Regulatory Policy Act (PURPA). These facilitate the sale of electric power produced from landfill gas to utility grids.
- Federal tax credit incentives that significantly improve the economics of the gas recovery process and of energy uses.
- State regulations that provide incentives to energy production.
- Emission restrictions that apply to energy equipment.

An overview of regulations, regulatory issues, and their consequences is presented in more detail in appendix D.

2. USE OF LANDFILL GAS AS A FUEL—TECHNICAL ISSUES

This section describes the technical issues regarding use of landfill gas as a fuel. Noted as background is that a very large body of information on energy and equipment fundamentals is available from a variety of sources, such as standard texts, and equipment manufacturers. As such information is widely available elsewhere, discussion of such standard energy technology aspects will be limited below. This and later sections concentrate on the unique aspects of landfill gas, compared to conventional fuels, for which different approaches are needed and from which performance differences, surprises, and problems, may arise. These aspects would normally be of greatest concern to energy users. Discussion also concentrates more on applications (detailed further in section 3) that appear the greater near-term opportunities. Thus electrical and boiler use issues are emphasized over, for example, those with pipeline gas preparation.

Some major issues that must be recognized and dealt with in energy use are

- determining the composition and characteristics of the gas
- potential corrosion effects caused by gas components
- effects of particulates
- gas cleanup
- dilution and other performance reduction effects
- load factor

These are addressed briefly below. In addressing these issues it is assumed that readers have at least some understanding of energy technology.

2.1 Gas Composition Analysis

In contrast to the case with more "conventional" fuels, users of landfill gas for energy may need to check their fuel composition fairly regularly. Landfill gas composition and energy content can change because of extraction procedures, leaks, or other factors. Gas systems often need to be "tuned" to provide a gas stream of appropriate quality to keep energy equipment running, and this tuning can require frequent well-by-well analysis. The gas will also contain a range of contaminants, whose level varies by landfill and over time. Since gas composition can have important energy consequences, composition analysis is reviewed briefly in appendix E.

2.2 Corrosion Effects

Serious equipment corrosion can be associated with landfill gas energy use. Corrosion is generally due to hydrogen chloride and fluoride resulting from combustion of halocarbons (chlorine- and fluorine-containing or halogenated, organic compounds) that are present in the gas. These compounds include, for example, the chlorofluorocarbons (CFCs) that were widely used in the past as refrigerants and aerosol propellants. Though CFCs are now being phased out because of environmental effects, they are still found in landfill gas (as old aerosol containers in the landfills release their contents over time). Other chlorinated compounds (such as industrial degreasing and dry cleaning solvents) also find their way into landfills and then into the gas.

Though levels of hydrogen chloride in combustion product gases are low, the hydrogen chloride is readily reactive with, for example, the metal in reciprocating internal combustion (IC) engines. Damage can result when metal in IC engine cylinder walls and other engine parts (including exhaust valves) reacts and is removed. Hydrogen chloride and fluoride can also react with metal in other equipment such as the tubes of boilers. Secondary damage can result from the buildup of solid corrosion products on the surfaces of moving engine parts. For example, deposits can reduce piston/cylinder or other lubricated surface clearances to zero, at which point the engine seizes and will be severely damaged. Case studies presented later in this report document such damage.

One engine manufacturer reports, based on many tests, that the content of chlorine in landfill gas, chemically bound in volatile compounds, is typically between 60 and 200 micrograms per liter of gas[1]. Because of corrosion effects, all engine manufacturers recommend that landfill gas be analyzed for its content of chlorine in chlorinated compounds (Chadwick, 1989). Various operating modifications (to be discussed later) are also recommended to prevent engine wear. The measures taken are generally, but not uniformly or completely, successful in limiting corrosion effects.

The gas can also contain other potentially troublesome chemical contaminants; for example acetic and other organic acids in the landfill gas condensate can react with steel. Problems from this source are, however, relatively minor.

2.3 Particulates and Their Effects

Experience has shown that particulate contaminants entering with the gas can build up in the oil used in many landfill gas engines, accumulating until they present problems. Particulate contaminants are of various types, including silica (a common soil component), iron salts (where steel is used in collection systems), and other normal soil components. (One interesting source of particulate contaminants in oil is a gaseous silicon compound, dimethyl siloxane, which will combust to products including silica. It is not removable by normal gas cleaning methods.)

Discussion of these compounds, and their effects on IC engines, are presented in references including Vaglia, 1989. Buildup of these components in oil above certain levels can contribute to wear. The materials can damage cylinder linings and rings; heavy deposits can also form on combustion chamber surfaces. The potential deleterious effects of particulate contaminants, as well as gaseous and liquid contaminants discussed earlier, make gas cleanup extremely important, as discussed next.

2.4 Gas Cleanup

Users of landfill gas for energy have often practiced what could be considered relatively limited cleanup (this excepts pipeline gas preparation, discussed later). Limited cleanup has provided satisfactory operating results at may sites including one case study site of this report. In other cases, however, the application of more apparently thorough cleanup, which for landfill gas can be considered "state-of-the-art," has not prevented "frozen" engines, or corroded equipment, and similar mishaps.

The primary "generic" cleanup approaches are filtration and condensate knockout. These are sometimes augmented by refrigeration, and less often by desiccation and other approaches.

Landfill gas filtration can employ the same type of equipment as used (for example) in large-volume air cleaning for internal combustion engines and combustion gas turbines. Filters may include simple particle size cutoff or coalescing models. Some description of these is included in the case studies. Refrigeration, to remove gas steam contaminants by condensation, is now practiced at a number of sites. Typically the gas stream may exit a landfill wellhead at a temperature exceeding 100°F, saturated with water vapor; cool (with condensate removal) to near ambient temperature on its way to the energy facility; and then be refrigerated further, for contaminant removal to a dew point (typically) of 1°C or about 34°F. This cooling will typically remove between 80 to 95 percent of the water and a fraction of other

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1 Personal communication, Greg Sorge, Waukesha Engine Division of Dresser Industries, Waukesha, Wisconsin, June 1991.

condensible contaminants (which is a function of the specific contaminant's vapor pressure, concentration, and other factors).

Where refrigeration is practiced, icing and high parasitic energy consumption normally limit gas cooling for cleanup purposes to a lower temperature slightly above the freezing point of water. The problem with this limit is that gas compounds that may cause corrosion problems, in particular the lower-boiling halogenated compounds that are a major part of the threat to equipment are not removed. Where prevention of condensate (ice or liquid) in the treated gas is a must—for example where compressed landfill gas is to be pipelined in cold climates—chemical desiccation may be applied to reduce dew points to well below the freezing point of water.

Approaches to more completely remove contaminants from landfill gas (but that still leave CO_2 in) have been applied; on a commercial scale, the Olinda site (Vaglia; 1989, GRCDA, 1986) uses the Selexol® process to remove contaminants. Other approaches, including absorption of gas components on activated carbon, have been demonstrated but only on a pilot scale (Watson, 1990).

As a summary observation, the cost-effective cleanup methods to date (except those for purification of gas to pipeline standards) all leave some fraction of contaminants, and particularly halocarbon components, in the gas. These contaminants are difficult to remove because of their low boiling points, concentrations, poor affinity for traditional solvents or a combination of these factors. The economic tradeoffs between more complete removal of various contaminants, and simply dealing with their effects when the gas is used for energy (by such means as more frequent engine oil changes) and other engine design and operational modifications, are not completely evaluated. The correlation between degrees of cleanup, observed levels of energy equipment corrosion, and performance needs further analysis.

These observations about cleanup pertain to most energy applications, except purification to pipeline quality gas, where far more thorough cleanup is applied to remove nearly all compounds except the methane component from the gas. Pipeline gas cleanup will be discussed further below.

2.5 Dilution and Other Performance Reduction Effects With Landfill Gas

Because landfill gas contains inert components—close to half carbon dioxide, and smaller amounts of nitrogen and water vapor—the performance of energy equipment is typically reduced compared to its performance with more "conventional" fuels such as pipeline gas. The equipment rating does not (as might first be thought) decrease proportionally to the gas energy-content reduction (i. e., the rating of equipment on 500 Btu per cubic foot [Btu/ft^3] landfill gas does not decrease to half the rating of equipment on 1,000 Btu/ft^3 pipeline gas). The fractional loss of rating (derating) instead depends in a complex way on fuel-air mix heating value and the combustion characteristics of the landfill gas used in the energy application. For naturally aspirated IC engines, the dilution effect of CO_2 at equal input flow rates of fuel-air mix can reduce the energy content of the gas in the cylinder's combustion chamber by about 8 to 10 percent, which will reduce the power output by this amount based on energy throughput considerations alone. The inert components can also have slight secondary effects in reducing flame-front velocity and combustion temperature, which reduce efficiency by a slight additional amount, so that the engine rating is reduced, overall, by 10 to 12 percent.

For energy equipment that burns pressurized nonstoichiometric fuel mixes, such as lean-burn IC engines and gas turbines, energy efficiency losses occur from another source: landfill gas at atmospheric pressure requires compression work that is a parasitic load. This is in comparison to pipeline gas, which is typically available at the required pressures. This tends to reduce efficiency (which can vary somewhat independently of output) by 5 to 15 percent for lean-burn engines on landfill gas.

In boilers and process and space heating applications where landfill gas is used in burners, heat output reduction at constant total fuel-air volumetric throughput is about 12 percent. About 10 percent of the reduction is because of inert gas dilution, with the remaining 2 percent because of increased stack heat losses. Refrigeration, if practiced for cleanup, can reduce efficiency by (very roughly) another 5 percent.

Overall, landfill gas energy users should be prepared for energy equipment rating losses that range between 5 and 20 percent, depending on the application.

2.6 Load Factor ("Use It or lose It")

One consideration regarding landfill gas is that there is currently no well-established way of storing it. It must be used essentially as it is generated, or it is lost. This means that it is most suitable for energy applications that are constant and continuous such as electric power generation, pipeline use (with purification), or continuous or near-continuous plant process use. Intermittent uses such as space heating can be practical, but are more efficient if combined with other energy applications, such as absorption cooling, that can assure higher year-round gas use. Some of the difficulty can also be overcome by using landfill gas to supply that part of the energy demand that is continuous, and other fuels to meet that part that may be variable.

3. ENERGY APPLICATIONS AND EQUIPMENT

Table 2 presents some of the more common and important current landfill gas energy applications and potential future applications. Considerations regarding their use are presented in the text. A brief discussion of applications, in order of increasing complexity, is presented next.

3.1 Current Applications and Equipment

3.1.1 Space heating (and cooling)

Normal gas-fired space heating equipment in widespread use can, with moderate burner and other modifications, use landfill gas. Such use has been limited to date because appropriately sized users of space heat are only infrequently located near landfills, and piping costs to more distant users can be prohibitive. Depending on climate and other factors, heat energy supplied by 500,000 cubic feet per day (cfd) landfill gas could correspond to heating needs of a 200,000- to 1,000,000-square-foot (or several acres of floor space) complex, large by normal standards. Space heating loads also vary undesirably over time, both during the day and by season; a higher overall load factor for the gas use can, however, be obtained by combining absorption chilling with space heating in temperate climate zones. Condensate

TABLE 2. LANDFILL GAS ENERGY APPLICATIONS

Current Applications[1]	Degree of Use[2]
Space Heating (and cooling)	Limited
Industrial Process Heat	Limited
Boiler fuel	Moderate
Electrical Generation: IC engines	Most common
Electrical Generation: Gas turbines	Common
Electrical Generation: Steam Turbine	Limited
Purification for pipeline use	Moderate
Potential Future Applications	
Electric generation using fuel cells	
Compressed methane vehicle fuel	
Synfuel or chemical feedstock	

1. Most significant actual or potential uses.
2. Statistics on use (such as in Government Advisory Associates, 1991) have included most, but not all, facilities. In defining degree of use in terms of the fraction of the total landfill gas recovered and used for energy in the U.S., "limited" is about 5 percent, "moderate" is 5 to 20 percent, "common" is 20 or more percent, and "most common" is about 50 percent. A recent, more comprehensive update on use has been presented (Thorneloe, 1992).

in equipment can be troublesome in space heating applications and poses a corrosion potential; gas cleanup and construction materials are important. Despite these limitations space heating can work well; one of the case study sites uses it. The equipment is also economical and available even on a small scale.

3.1.2 Process heating and cofiring applications

Several industrial applications, such as lumber drying, kiln operations, and cement manufacturing, can be attractive applications for landfill gas. An advantage of many industrial processes, including drying processes, is that fuel is required continuously, 24 hours a day. Landfill gas can be also used as a supplemental fuel that meets a portion of the total demand. Many industrial processes such as cement manufacturing may be relatively insensitive to the contaminant components resulting from landfill gas combustion, and their gas cleanup costs may be quite low in such applications.

One application that can be attractive because of absence of gas cleanup needs, and frequently plant proximity, is co-firing of the gas as supplemental fuel in a waste-to-energy plant.

3.1.3 Boiler fuel

This is an attractive use, particularly for large industrial boilers with constant demand, or where landfill gas can be used as a supplemental fuel. Conventional equipment can use landfill gas with relatively little modification. One case study of this report, in section 5, describes a boiler application. To the extent that sensitivity to gas contaminants can be determined, boilers may be less sensitive and their gas cleanup needs less than, for example, IC engine applications. The capital costs of boilers, discussed later, are also attractive. Although steam users are not frequently located near landfills, the siting of boilers, or for that matter other uses of 3.1.2, near landfills can be an alternative worth consideration.

3.1.4 Reciprocating internal combustion engines with electric power generation

Reciprocating internal combustion engines, almost all driving electrical generators to produce electrical power, are the most widely used landfill gas fueled energy equipment. Electrical generation occurs because the output can be accepted (if not always at a high price) by the electric utility grid 24 hours a day, and the power sale may be facilitated by provisions of PURPA. Although available statistics are far from complete, data in the 1991 GAA yearbook (Government Advisory Associates, 1991) suggest that electrical generation using reciprocating internal combustion engines is practiced at about 50 percent of the landfill gas energy sites in the U.S., and electrical generation using gas turbines is practiced at an additional (approximately) 15 percent, so that electrical generation is practiced at about 65 percent of the total sites.

Almost all larger engines used in this application are made by three manufacturers—Caterpillar, Cooper-Superior, and Waukesha. Each has in place more than 20 engines at landfill sites in the U.S. Lists of the sites where the various models of the three manufacturers' engines are in place are presented in GRCDA/SWANA, 1989.

The engine-generator set (genset) equipment is well developed and is used not only with landfill gas but for numerous other applications; the landfill gas sets sold by the three manufacturers are largely identical to those of the complete "stand alone" package sets sold for use at remote sites such as offshore oil platforms and other remote sites requiring electric power. Currently increasing degrees of automated engine monitoring and control reduce the need for on-site operator attention. Genset electrical capacity with landfill gas is typically 100 kW and up, with capacities between 1 to 10 megawatts (MW) being most common because of economics. Multiple gensets are used to obtain the higher outputs.

The reciprocating engines are most commonly "lean burn" turbocharged designs that burn fuel with excess air. Less commonly, they may be "naturally aspirated" without turbocharging (which as the term is used also implies stoichiometrically carbureted, with air in the fuel-air mix just sufficient to burn the fuel). The naturally aspirated engines are easier to operate because they are less complex, but they have reduced power output and unresolved emissions issues. When operated on landfill gas, reciprocating engine power ratings are commonly reduced by 5 to 15 percent compared to operation on natural gas. This derating is caused by different factors, depending on engine type: dilution effects in naturally aspirated engines and parasitic load in lean-burn engines. The overall heat rate for electrical generation with the more commonly used lean-burn engines (after all parasitic loads are deducted), is about 11,000 to 14,000 Btus of landfill gas higher heating value per kilowatt hour. For smaller scale electric generation, this efficiency is quite good; this is one reason these engines are popular.

Landfill-gas-fueled generation comprises a rather small portion of the total use of such engines. Despite this, the three manufacturers of these engines have modified both design and operating procedures so that they can be said to have "landfill-gas-adapted" engines. With turbocharged engines, the need to compress landfill gas initially at close-to-atmospheric pressure normally poses added capital and energy costs compared to pipeline gas fueling. Compression of the fuel-air mix post-carburetion avoids some of these costs and (along with other landfill-gas-specific adaptations) is now being applied by Caterpillar in their 3516 series engines (Chadwick, 1990). Various design modifications, by all manufacturers, include parts modifications for corrosion resistance, such as chrome valve stems and modified piston rings; proprietary modifications are frequently involved[2]. One of the important operating modifications relates to engine oil as recommended by the engine makers (Chadwick,1989). Oil is checked much more often than is usual in other applications, sometimes as often as every 50 hours. Oil is changed frequently, as often as every few hundred hours or when relatively low contaminant limits for chloride (chloride can indicate corrosion as discussed earlier) or metal content are observed, according to manufacturer's guidelines. Specialized lubricating oils with high total base numbers (TBN; for discussion see Gonzalez, 1987) are now recommended for landfill gas use. Chemically, the bases in these oils give the acidic combustion products something to react with before they react with the metal of the engine. These can be thought of as helping engines the same way that antacids help people (and by neutralizing the same acid).

With the design and operating modifications that have been made for landfill gas engines they can generally be operated successfully at landfills. Yet, for reasons that are still not completely understood, (but that may relate to presence or absence of various landfill gas operational and design adaptations) some engines at some landfills encounter serious operating problems. They are most frequent during initial operation.

3.1.5 Gas turbines

Combustion gas turbines are also widely used as landfill-gas-fueled prime movers (i.e., sources of mechanical power) at landfills to drive generators. The justifications for their use in electric power generation are the same as those for reciprocating internal combustion engines.

The gas turbines used at nearly all U.S. landfill sites are either Saturn or Centaur models made by the Solar turbine division of Caterpillar. As of 1989, more than 30 Saturn or Centaur turbines were in use at more than 20 landfills; lists of their applications are presented in Esbeck, 1989, and Maxwell, 1989.

The principal power-rating consequence of using landfill gas as opposed to pipeline natural gas in turbines is a decrease of 10 to 15 percent in the power rating, due to the parasitic load associated with compression of the landfill gas fuel to the turbine. When all factors are considered, a turbine has a somewhat lower net efficiency in typical landfill gas applications than a reciprocating internal combustion engine. The heat rate of smaller turbines is typically about 16,000 Btus landfill gas higher heating value per kilowatt hour generated when parasitics are accounted for.

A factor to be considered in turbine operation is that turndown performance is poor—that is, turbines do best at full load, and poorly if gas supplies are less than needed to supply full load operation. Gas contaminants have also apparently caused serious problems for some landfill-gas-fueled gas turbines. These have included combustion chamber erosion and deposits on blades, resulting in severe and

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2 Personal communication, Curtis Chadwick, Caterpillar Corporation, Mossville, Illinois. September 1991.

unanticipated damage in a few cases. A well-documented instance of turbine damage and associated cost is presented in Schlotthauer, 1991. The use of improved coalescing type filters (in combination with other modifications) has apparently solved or forestalled problems at sites described in Schlotthauer, 1991. One danger of severe damage to turbines that does not exist with conventional fuels is that a large "slug" of landfill gas condensate in the piping system could mobilize and reach the turbine (it is a consideration with IC engines as well). Methods for intercepting such slugs are required when this danger exists at turbine sites.

Although problems are seen at some turbine sites, they appear to have solutions. Turbines have the advantages of low operator attention and maintenance needs.

3.1.6 Steam-electric

Steam-electric generation burns landfill gas in a boiler to produce high-pressure steam, which then drives a steam turbine to generate electricity. A large amount of gas is needed for economic and efficient operation; the result is that only a few U.S. sites use this approach, with few additional candidate sites apparent where a stand-alone plant might be attractive. The economic difficulties of scale are a lesser problem, however, if landfill gas can be delivered to supplement the conventional fuel at a conventional steam-electric power plant; limitations here can be either piping costs or the on-stream time of the conventional electric plant.

3.1.7 Purification to pipeline quality methane

Very stringent cleanup technology is applied to remove all components except the desired methane at a small number (under 10) of the larger U.S. landfills to produce gas for pipeline use. The principal objective not required of other cleanup approaches is nearly complete CO_2 removal, but the criteria are also stringent for the removal of other contaminants. The technology for cleanup to pipeline standards (with needed gas compression to pipeline pressure) is expensive; most such projects were initiated in the U.S. at larger landfills, where the economics of scale are attainable, during the early 1980s when gas prices were high. Projects operating today all have favorable long-term contracts.

Several technologies are available for the necessary cleanup. Many of these originated as CO_2 removal approaches applied first in the natural gas industry, through further adaptations for landfill gas appear to have been major. Details of these can be found in several sources, including a rather comprehensive review by Koch, 1986. The largest operator of facilities producing pipeline methane from landfill gas is Air Products and Chemicals, Inc. (APCI) and the process in use by APCI is the Gemini® process; provisions for this process's contaminant removal and destruction are interesting and discussed in Koch, 1986. Because of recently falling natural gas prices, and because the largest landfills with best economics of scale already have energy projects, additions to pipeline quality gas production from landfill gas in the near future may be limited.

3.2 Potential Future Technologies

Landfill gas may be applicable to several technologies under development; these include fuel cells, compressed gas vehicle fuel, and possibly synfuels production. A brief review follows.

3.2.1 Fuel cells

Fuel cells are essentially electrochemical batteries. They can operate on various primary fuels (feedstocks) such as oil, natural gas, or coal. The potential primary fuels include landfill gas. As an intermediate step the primary fuel is converted at high temperature to "synthesis gas," which is a mix of hydrogen, carbon monoxide and dioxide, and other gases. This synthesis gas is what feeds the fuel cell.

Further discussion of fuel cell operation on landfill gas is presented in Leeper, 1986. Advantages include low emissions and quite high thermal efficiency (near 40 percent). It is a technology that has particular promise for economical electric power generation on a smaller scale. The technology is considered sufficiently interesting that the U.S. EPA will be funding further trials (Sandelli, 1992).

3.2.2 Compressed gas vehicle fuels

Vehicle fueling with compressed methane is of high interest for environmental and other reasons, and technology for such fueling is advanced. It was reported that in 1990 at least 700,000 vehicles operating worldwide were fueled by natural gas (Rosen, 1990); such fueling is economically competitive in several situations, and expanding. Digester gas has also been used at sites including Modesto and Los Angeles, California (EMCON, et al., 1981). Using landfill gas would involve some purification, possibly to near pipeline quality, then compression of the purified gas for reduced-volume storage and use on board vehicles equipped with conversion kits. Although landfill gas applications have apparently been few, an early study (EMCON, et al., 1981) projected favorable economics. The most attractive use is for fleet vehicles, and in particular refuse trucks, which would need to return frequently to the landfill where the gas would be available. Gas availability and economics both dictate that the vehicle fleets should be large.

3.2.3 Synthetic liquid fuels and chemicals

Various technologies are available that could convert landfill gas to liquid fuels. These include hydrocarbon production by Fischer-Tropsch, methanol synthesis by various routes, including chemical catalysis at high pressures (Ham et al., 1979), or by partial biological oxidation. Most of these synfuels approaches have been examined for large-scale feasibility using feedstocks such as gas from coal. Synthesis gas-based chemical processes (for example, acetic acid manufacture) are also possible. These technologies are projected to produce expensive products, even at the larger scales. The principal difficulty with any of these, particularly fuels, would be that landfill gas generation can support a plant size that is generally only 1 to 10 percent of the plant size normally contemplated for these technologies. The small scale required with using landfill gas would appear to imply very high costs.

4. COST AND REVENUE COMPONENTS

This section addresses cost and revenue components and particularly issues such as site specificity and cost variability that are considered to be important to energy users. It is not intended to provide extensive cost detail here, although some examples of costs and cost ranges are provided for illustration. Comment is also presented on issues including electric revenue requirements, initial cost estimating, and economics as barriers to landfill gas energy applications.

4.1 Components of Cost and Income

The cost and revenue factors to be considered consist of (1) capital costs, (2) operations and maintenance costs, (3) royalty payments, (4) tax and other credits, and (5) energy-related revenues.

- Capital costs include costs associated with energy conversion and sometimes other associated equipment such as that for gas extraction. They normally include the "up front" costs of implementing the project and plant, and may include other large lump sum costs incurred during the project, such as for equipment replacement. Some examples of capital costs include those for initial site improvements, energy equipment, buildings, and pollution abatement equipment. They can also include initial legal costs, commissions, rights to gas, permits, and the like. They can vary widely as discussed shortly.

- Operating and maintenance costs include costs associated with operating and maintaining the capital plant. Items such as labor, equipment maintenance, materials, debt service, and relevant taxes fall in this category. Operating and maintenance costs can vary substantially and depend on factors including the end use, landfill characteristics and configuration, gas composition, local rules and regulations, and many others.

- Royalty payments are continuing costs that are usually proportional to energy revenue. Royalties are negotiated and are occasionally changed as the marketplace, or other factors, change. Royalties may be paid to the landfill owner, owner of the gas extraction or delivery rights, or initial project developer. When they exist (a fair fraction of projects have none) they are usually in the range of 5 to 20 percent of gross energy sales.

- Federal tax credits are benefits proportional to gas energy delivery that were legislated by Congress (Section 29 of the IRS code). These credits are a direct dollar-for-dollar offset to federal tax that would otherwise be payable by the business entity providing the gas. The tax credits are allowable for extraction systems installed before the end of the year 1992 and will extend through the year 2002. They have had a significant effect on improving economics and viability of projects that might otherwise not have been implemented.

- Revenues for energy sales are most frequently based on prices of competing fuel or energy. They can be based on costs of the equivalent in heating value of a fuel grade petroleum product, on electricity sales (where cost is fixed by provisions of PURPA), or on other energy commodities. Energy market price fluctuations can materially and often adversely affect economics. Long-term contracts can often be executed, that fix prices per unit of output and provide a substantial degree of security to developers.

Possibly the most important aspect of costs, revenues and other benefits is their specificity to site and situation; the site-to-site variation, even with the same application and scale, is far greater than is usual with other energy technologies. The reasons include

- Component capital cost variations: Key components such as gas cleanup, utility provisions (e.g., on-site water supply), and utility interconnects can vary in cost by at least an order of magnitude. Other capital costs, such as those for gas and power sale contract rights and pipelining, can be zero for many projects but may add substantial percentages (up to 25 percent or more of the costs) to others. Energy equipment costs can vary depending on details and whether the equipment is new or used. Fixed costs, which are proportional to capital costs, vary correspondingly.
- Operating cost variations: As an example, landfill-gas-specific maintenance costs relating to gas contaminants can vary by up to an order of magnitude. Other costs such as royalties (where they exist) and operator cost can vary several fold.
- Benefits accruing per unit of energy delivered can vary (by about a factor of five for the example of electric power), and also depend on whether the energy is sold to the utility transmission system or avoids utility retail cost. Nonenergy credits allocated for benefits such as for gas system maintenance and adjustment, and emission control vary widely.

Development of detailed economics regarding application, scale, and the host of site-specific factors that can exist is, as noted, beyond the scope of this report. (Also it should be noted that costs may be expressed in several different ways in literature sources, with many data appearing contradictory). Further discussion of various categories of costs—capital and capital-related, operating costs, and revenue and benefit components—is presented in appendix F. Examples of cost data, presented next, illustrate some typical costs and their levels of variation.

4.2 Cost Data: Examples

4.2.1 Hypothetical generating facility example: Cost component ranges

Table 3 presents example ranges for cost and benefit components that might be experienced for the hypothetical case of a 1 MW electrical generating facility. (As stated earlier about 65 percent of landfill gas energy facilities involve electrical generation). Note that capital costs are installed, that is, engineering, design, permitting, and other costs are factored into the costs; ranges given are "best estimates" generated by the authors for this report. The ranges suggest the potential for cost variability, even where (as in this example) the application (electrical generation) and scale (1,000 kW) are fixed. Note that electric sale price and other benefits per unit output may vary over an even greater ratio than cost factors. Economic factors may impede the energy use of much of the landfill gas that is generated, as discussed in more detail below.

4.2.2 Reported electric facility capital costs: GAA Yearbook

Some reported data on capital costs for electrical generation, are also illustrative. In the Government Advisory Associates' *1988-1989 Methane Recovery from Landfill Yearbook*, 38 electrical generating facilities report information (capital cost and nominal electrical generating capacity) from which costs per kilowatt of capacity may be calculated. The figures are for both current and projected facilities, including internal-combustion-engine-based facilities, gas turbine facilities, boiler/steam turbine electric facilities, and in some cases facilities using unspecified generating methods. The capital cost per kilowatt for each of these individual facilities, coded by facility type, is plotted against plant capacity in figure 1. All costs have been adjusted to 1991 dollars. The data probably have imprecisions for several reasons (additional plant costs experienced for postconstruction modifications may be omitted, experienced output may not

TABLE 3. COST AND REVENUE RANGE FOR 1 MW ELECTRICAL ENERGY PROJECT

Capital Cost Ranges (Basis: 1 MW capacity)	Range of Capital Cost (thousands)		
Administration, Development and other[1]	30	-	1,000
Extraction system	200	-	1,000
Pre-treatment system	10	-	500
Energy conversion equipment	500	-	2,000
Typical Range[2]	850	-	4,500
Typical Operating Cost Components		$/kWh	
Operations and Maintenance	0.01	-	0.03
Debt Service (interest and amortization)[3]	0	-	0.04
Return on Investment (ROI)[3]	0.01	-	0.04
Other (royalties, etc.)	0	-	0.02
Typical Range[2]	0.03	-	0.09
Typical Revenue Components			
Tax Credits (where applicable)	0	-	0.011
Other benefits (see text)	0	-	0.01
Electric Power Sales	0.02	-	0.10[4]
Typical Range[2]	0.03	-	0.11

Notes:

1. Costs could include payment for the rights to the gas, or for the power sales contract, or to obtain an equity position in the project: see section 4.1 for more detail.
2. All extremes are unlikely simultaneously within the same project, so typical ranges are less than possible span through adding components.
3. ROI may substitute for debt service - one will increase as the other decreases.
4. May include capacity payments as well as payments for kWh delivered.

equal nominal, and so forth). However, the figure illustrates the variability (and, the lack of obvious pattern) of landfill gas electrical generating facility capital costs, even allowing for the databases' imperfections. The cost data and their scatter are undoubtedly explainable on the basis of site features and variables discussed above but detailed analysis is necessarily outside the scope of this report.

4.3 Other Economic Issues

In addition to cost ranges, of interest to many energy users will be the range of required revenues, the uncertainties of initial cost estimating, and constraints of economics on energy uses. Each of these issues are discussed as follows.

4.3.1 Revenue requirement for electric power generation

The average power revenue required to justify an electric generation facility at a scale of 1,000 kW (1 MW) or greater is regarded as being most typically about 5 to 8 or more cents per kWh[3]. Caveats are that the equipment must operate with an acceptably low down time and few problems due to factors such as energy equipment breakdowns or gas supply problems. There are obviously also sites where costs combined with return criteria can result in sale prices both above and below this range.

4.3.2 Initial cost estimating

Accurate initial cost projections are difficult to develop, and initial cost underestimates—leading to unwise projects—are frequently made (this problem is exacerbated when additional costs, such as for improved gas cleanup, or equipment modifications, are found to be necessary as the project proceeds). Those interested in developing economics for applications may wish to develop their initial data working with others experienced with landfill gas energy applications. The intricacies of costing and implementing an energy application are such that many—possibly most—of the smaller landfill owner/operators tend to form partnerships and participate with entities already experienced in landfill gas energy applications, who can provide help in stages throughout a project: examining use options, projecting economics, and continuing through selecting and implementing the (presumably) best option.

4.3.3 Economic impediments to energy applications

Landfill gas energy projects, including some of those to be described later in this report, can do well economically. However, as can be inferred from table 3 and figure 1, low energy sale prices can combine with high capital and operating costs at many sites. Individual landfills with substantial methane generation often cannot find economic energy applications for the gas, and their energy potential is wasted. Well-developed options for energy applications for smaller landfills and generation rates are also lacking. Precise figures are not available but based on GAA (1988), a very small percentage (well under 10 percent) of landfills with outputs less than 200 cfm output (that could support 500 kW) appear to have energy systems. Those means suggested for barrier reduction and facilitation of energy uses under less than favorable circumstances are referred to in Section 6.

3 Authors' estimates; also discussed with Christine Nolin, Cogeneration and Independent Power Producers Coalition, Washington, D.C.

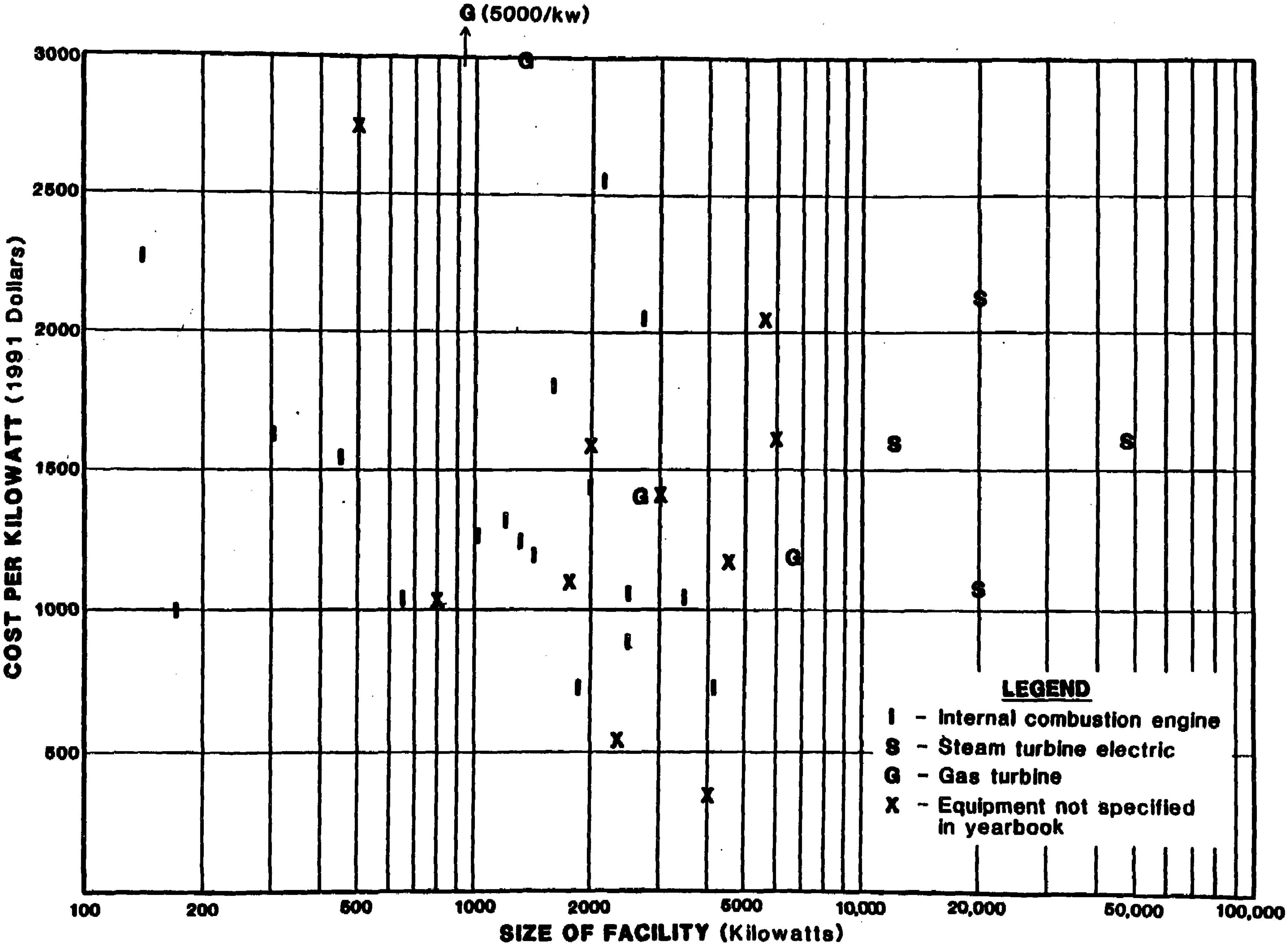

Figure 1

COSTS PER KILOWATT VERSUS SIZE

For 38 facilities reporting capital costs in 1988 "Methane Recovery From Landfill Yearbook" published by GAA

5. CASE STUDIES

This section describes experiences with projects where landfill gas has been used in energy applications. These include six projects in the U.S., references to four case studies in the U.K. (provided as appendix K) and a discussion of other relevant literature. The case studies provide information considered of most interest to readers (including, in particular, potential energy users) such as how the decision to implement the project was made, facility details, and particularly the energy equipment, and its experienced performance and economics.

It should be recognized that limits exist on the amount of detail that can be presented for each case. Information presented in various areas is intended to be illustrative and representative (rather than comprehensive); it is hoped that it will nonetheless provide readers with useful overviews of each project's experience.

5.1 Electric Power Generation and Space Heating Using Landfill Gas: Prince George's County, Maryland

5.1.1 Introduction and general overview

The Brown Station Road Landfill is located in Prince George's County about 15 miles east-southeast of downtown Washington, D.C. Gas from the landfill is used to supply both the electrical and the heating needs of a County building complex and also electricity for export sale to the local utility. The energy equipment comprises a landfill gas cleanup and pumping station, a 2-mile pipeline, three engine-generators, and a boiler that supports the heating and hot water system of the 235,000-square-foot County Correctional Complex (jail). The facility was engineered by the Maguire Group, Inc., of Foxborough, Massachusetts. Curtis Engine of Baltimore, Maryland, the regional Waukesha Engine distributor, was also heavily involved in subsequent operation of the project. A photograph of the engine-generator set at the site (discussed later) is shown in figure 2.

General site and facility information is shown in table 4. The facility was wholly financed and is wholly owned by Prince George's County. The County also receives all benefits; these include the operation and management of the landfill gas extraction system, avoided costs for electrical power and heat for the correctional facility, and revenues from power sales to the local utility, Potomac Electric Power Company (PEPCO). The energy facility met more than 99 percent of the heat and electrical needs for the correctional facility in the County's most recently ended fiscal year. The gross benefits to the County are calculated to currently be running about $1.2 million per year.

5.1.2 History of project implementation

Initial impetus for the Brown Station Road landfill energy project came from Prince George's County. County staff recognized in the early 1980s that landfill gas emissions would need to be abated by a landfill gas system and, that the gas would also represent an energy resource. Help from the Applied Physics Laboratory at Johns Hopkins University, which was conducting landfill gas related investigations, was obtained in 1982. The Laboratory used Brown Station Road waste placement data to develop methane generation projections, and carried out preliminary economic projections; results showed that sufficient gas would be available to support an energy recovery system, and that energy recovery had favorable economics.

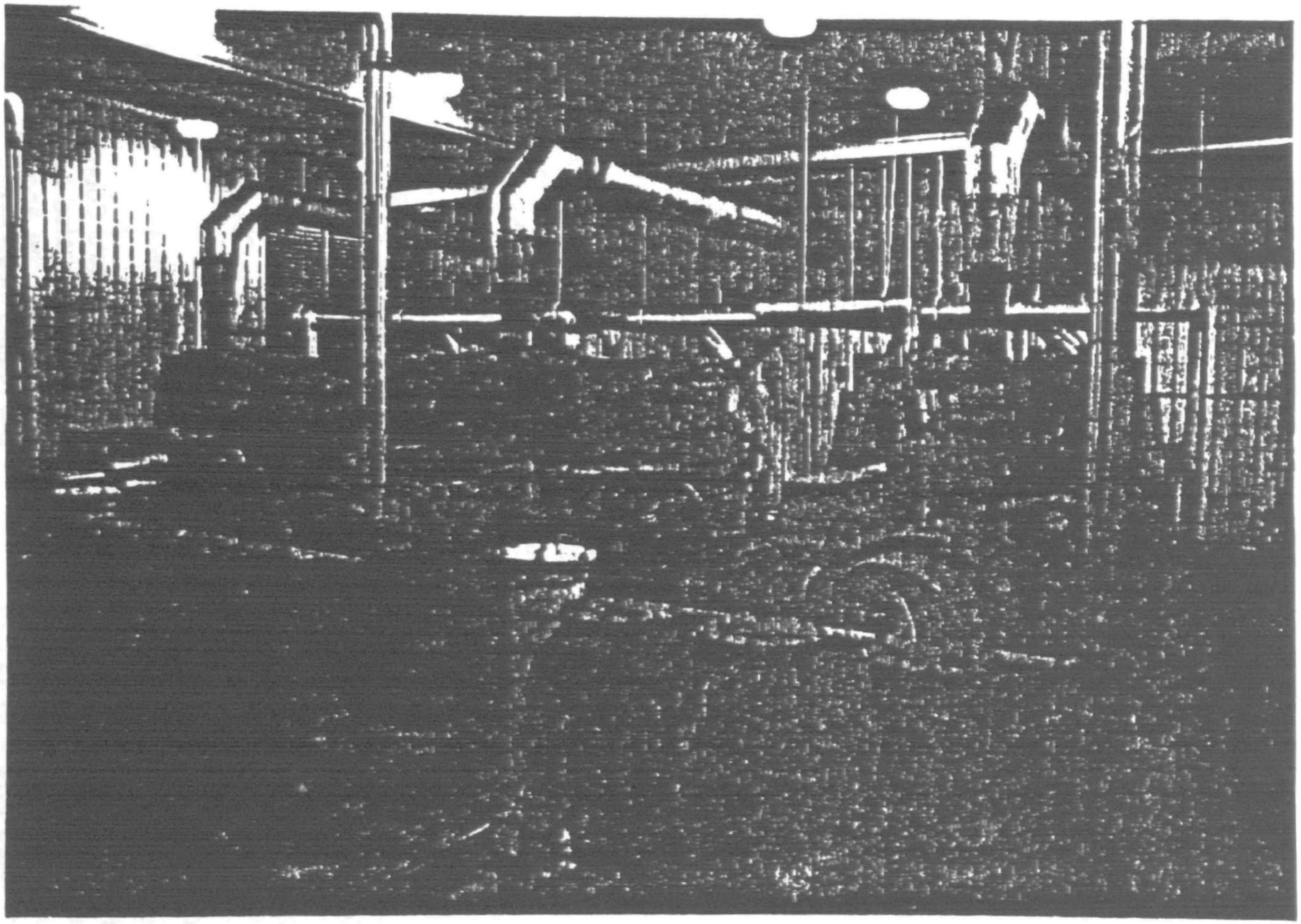

Figure 2 Waukesha Engine-Generator Sets at Brown Station Road Landfill. These engine generator sets furnish nearly all electrical needs of nearby correctional complex.

TABLE 4. GENERAL FEATURES: BROWN STATION ROAD ENERGY FACILITY

Location: Brown Station Road, near Upper Marlboro, Prince George's County, Maryland (15 miles east of Washington, D. C.)

Application: Electric generation and space heat. Electric and gas utilities are supplied to a 235,000-square-foot County Correctional Complex; surplus electricity is sold to the utility company.

Energy equipment: Pumping station, 2-mile pipeline, three Waukesha engine-powered generators, correctional complex space heating and hot water system

Equipment owned by: Prince Georges County

Equipment operated by: Curtis Engine

System design: Maguire Group

Landfill owner and operator: Prince George's County

Current tonnage in landfill: Approximately 4 million tons

Gas collection: County owned, operated by Curtis Engine

Maguire Group Inc., an architectural/engineering and planning firm (then known as CE Maguire) of Foxboro, Massachusetts, was retained by the County to evaluate the technical and economic feasibility of potential landfill gas uses. This study used the sustainable extraction rates established in the John Hopkins report. Maguire's analysis examined the County energy demands and use options.

Based on probable methane availability, Maguire developed several different energy system options involving variations on both equipment and timing of installation. In order of complexity and also rates of methane use (increasing from A to F below) the options were

A. Heat and hot water to correctional complex

B. Heat, hot water and steam absorbtion air conditioning to correctional complex

C. Heat, hot water and power to correctional complex.
(Three generators, surplus power to PEPCO)

D. Heat, hot water and power to correctional complex
(Four generators, surplus power to PEPCO)

E. Heat, hot water and power to correctional complex
Heat, hot water to Upper Marlboro County Building Complex (UMC)
(Three generators, surplus power to PEPCO)

F. Heat, hot water and power to correctional complex
Heat, hot water and power to UMC
(Four generators, surplus power to PEPCO)

Comparison was on life cycle costs, revenue, and other bases. From these, the County selected option C: to use landfill gas to directly supply the heating system of the correctional complex, and to fuel gensets to provide power to the correctional complex and for export. The possible financing and ownership options were also evaluated, and county ownership with municipal bond financing was selected.

The energy system was implemented in a phased program beginning with initial design, and construction of the landfill gas wells. This was followed by installation of the compressor building, gas transmission line, and engines. The energy system was completed concurrently with the County Correctional Complex, the needs of which it was to supply. The first electricity was produced by the facility in July 1987.

Note that the negotiations with PEPCO, regarding sales price for cogenerated power and cost recovery mechanisms for the two-way interconnect, were quite extensive (and were not completed until June 1990, almost 3 years after the first power production).

TABLE 5. LANDFILL AND GAS SYSTEM CHARACTERISTICS: BROWN STATION ROAD

Landfill

Location: Off Brown Station Road, Prince George's County, 15 miles east of Washington, D.C.

Type: Mound Fill

Date Opened: 1960

Waste in Place: Approximately 4 million tons

Current Waste Fill Rate: 450,000 tons per year

Total Fill Area: 100 acres

Area Now Filled: 40 acres

Area of Extraction: 20 acres

Climate: Temperate, seasonal

Annual Rainfall: 45 inches

Daily and Intermediate Cover Soil: Various, as available

Final Cover Soil: 2 feet of clay

Depth of Waste: Approximately 100 feet

Gas Extraction System

Type: Vertical wells—currently 29 active

Collection Unit Pipe Material: PVC

Lateral/Main Header Pipe Materials: HDPE and PVC

Location of Piping: Laterals and main header about 1 foot below surface

Collection System Details: Spacing between wells at 200 feet. Depths are 60 to 80 feet (or 60 to 80 percent of the waste depth)

Current Collection Rate: 695 cfm, or 1,000,000 cfd

Well Adjustment Protocol: Wells below 50 percent methane throttled, over 50 percent opened, as required

Gas Analysis: 55 percent methane by volume

Gas Analysis Frequency: Six times per month

5.1.3 Landfill and landfill gas system

Details of the landfill and landfill gas system are shown in table 5. The Brown Station Road Landfill is a "mound fill," that is, it lies over the original soil surface in its "footprint." The landfill generates methane at a rate in excess of current energy conversion needs; generation is expected to increase still further as the filling continues at the current rate over the next 10 or more years.

One noteworthy aspect of the landfill's gas is its content of halogenated organics. These are indicated by a total chlorine content measured (in early tests by Waukesha, provided through Curtis Engine) at 200 micrograms per liter (µg/l). Waukesha states that these measured concentrations were among the highest in Waukesha's experience and certainly are related to some initial engine problems (discussed later).

Also worth mentioning are the gas system's past problems of a not-uncommon type associated with differential landfill settlement which resulted in pipeline blockages from condensate pooling at low points. Gas supply limitations due to blockage became so severe that much of the original system had to be replaced in 1990; the extraction system has worked well since the 1990 repairs.

With the initial problems now corrected, methane and gas field monitoring and adjustment by Curtis Engine, a gas stream of good quality (55+ percent methane) at a rate of up to 800 cfm is provided to the energy facility with standard monitoring and adjustment procedures.

5.1.4 Energy facility and equipment

A schematic/block diagram of the facility's landfill gas processing and energy equipment is shown in figure 3. For convenience, the energy system discussion covers (sequentially) the components of the compressor station, the pipeline, the electrical generating station, and the heating and boiler system of the correctional complex. A list of significant equipment items in each of these categories is presented in table 6.

Compression station and initial gas pretreatment. The current configuration has been modified somewhat from its initial design (further discussion later). Gas from the collection system arrives at the compression station at a pressure, determined by rate of energy usage, that at high gas use rates is about -20 inches water gauge. A 1,500 gallon inline tank is used to intercept and collect condensate. Gas then passes through moisture separators and a coalescing filter. Gas pumping is by four oil-lubricated compressors, located after the coalescing filters. These compressors are driven by smaller, dedicated IC engines, fueled by the processed landfill gas. Gas, pressurized to 100 psi, is then cooled to 36°F in an aftercooler from which further condensate is drained; the gas is then sent through a demister and several further steps including filtrations and a desiccation step, to a dewpoint of approximately 20°F (see figure 3). After desiccation, gas is odorized for safety, using conventional natural gas odorant. A stream of gas is extracted to fuel the compressor engines (described above), with the balance of the gas being pumped through the pipeline (specifications shown in table 6) to the gensets and correctional complex.

Engine-generator building. At the engine-generator building, after passing through further filters, the gas fuels a set of three Waukesha lean-burn engine powered gensets (table 6). These gensets are providing almost all of the correctional complex's electrical needs (99 + percent, discussed later). To reduce noise to the adjacent correctional complex and the surrounding area (which is populated), the engine-generator building is double-walled.

Correctional complex heating and cooling. The rest of the landfill gas from the pipeline goes to fuel the heating and hot water system of the correctional complex. This is a system based on two Cleaver-Brooks 350 hp package boiler units of largely conventional design capable of operating on Number 2 fuel oil, or pipeline natural gas. Adaptations enable operation on, and easy switchovers among, the fuels. When operated on Number 2 oil, County records show that it would consume about 650,000 to 700,000 gallons annually.

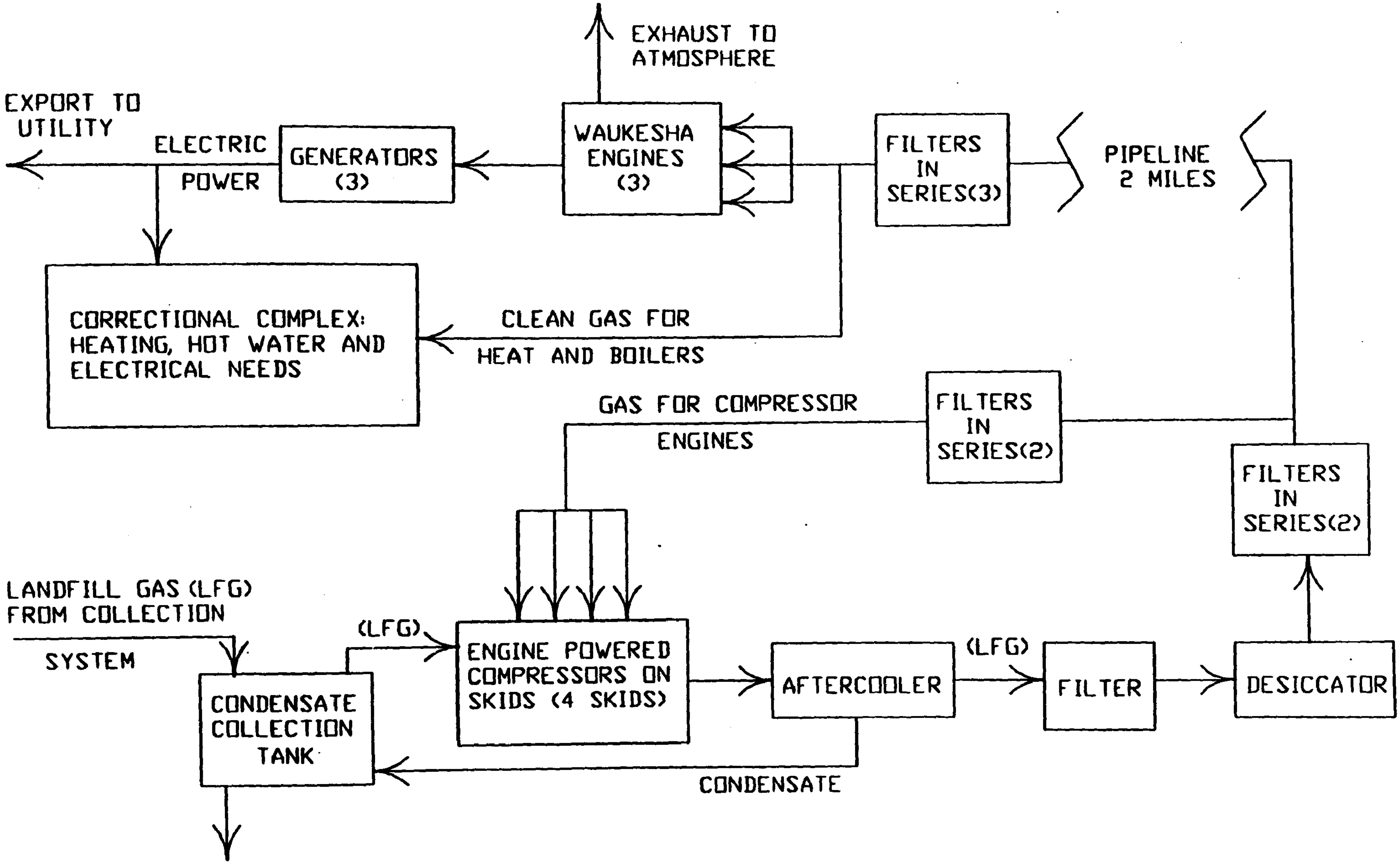

Figure 3
Energy Facility At Brown Station Road Landfill
Simplified Block Diagram Showing Major Components

TABLE 6. MAJOR EQUIPMENT ITEMS: BROWN STATION ROAD ENERGY FACILITY

Plant Inlet Section (Through Compressor)

Condensate collection on inlet header from gas collection system: 1,500-gallon fiberglass tank, unbaffled

Compressor building (at landfill)

- Moisture separation: Mist pads manufactured by NECO Industrial Plastics
- Compressor skids (four in parallel): Sullaire screw compressors, model SA-581, 550 cfm; Waukesha F1197 GU engines (215 hp) to drive compressors; Waukesha model 04M heat exchanger for gas cooling
- Desiccator: Henderson Engineering Model HP-2400 (uses Mity-Dry proprietary desiccant, dewpoint -20°F)
- Filtration: Four finite element filters, 0.3 micron nominal cutoff, one before and three after desiccator
- Further gas filtration for compressor engines: Nelson and Pall well filters, 0.3 micron absolute cutoff

Pipeline and Energy Equipment

Pipeline: 2 miles long, 8-inch diameter, schedule 80, carbon steel, polyethylene coated and cathodically protected

Engine-generator building (double walled for sound suppression)

- Landfill gas prefiltration before gensets: One Pall well 0.3 micron absolute cutoff, three Nelson models 95802A
- Three Waukesha 5970 GL gensets, nominal rating 850 kW each. Engines modified with chrome valve stems and guides, modified piston rings.

Correctional Complex Energy Equipment

- Heating System: Two Cleaver-Brooks fire tube package boilers, 350 hp rating. Heat provided by hot water through coils; domestic hot water also provided.

While the landfill-gas-fueled energy facility meets most correctional complex needs, uninterrupted utility supplies are obviously of utmost importance and the complex also has conventional utility hookups.

Performance and availability, initial experience. This system was one of many landfill gas energy projects that have encountered serious (but not insurmountable) problems, in this case on start-up. One of the lean-burn Waukesha engines had operated for less than 500 hours in 1987 when, before the first scheduled oil change, the engine seized. Examination of the seized engine showed evidence of serious corrosion (paint peeled from interior crankcase parts, discoloration and serious deposit buildup on metal surfaces). The engine had seized because deposit buildups had reduced piston clearances to zero; high levels of oil contaminants were found.

The situation was reviewed by Curtis, Waukesha, and others. Landfill gas from the Brown Station Road Landfill was confirmed to contain high levels of chlorinated organics (which as reviewed earlier, combust to acid products that in turn cause damage). The facility's gas cleanup system (which had an initial design that appeared relatively conservative by standards of successful energy systems elsewhere) was modified. The modifications, made with major input from Curtis, Waukesha and Maguire included additional filtration and substitution of stainless for carbon steel piping in the plant sections before desiccation, resulting in the current configuration.

Waukesha, through Curtis, also applied engine modifications developed to address landfill-gas-related problems. These included hardened valve guides, chrome valve stems, modified piston rings and elevated coolant temperatures. Operations were also modified, including more frequent oil checks and changes.

Although satisfactory engine operation was obtained with these modifications, gas recovery system problems associated with landfill subsidence also occurred during and after the initial engine problems; as noted, gas supply inadequacies restricted operation and were only fully resolved with replacement of part of the gas system in 1990.

Brown Station Road experience provides a good example of the severity of problems sometimes encountered in energy conversion projects. Between July 1987 (when electricity was first generated) and the present, losses of generated electric power, due to corrosion problems and associated retrofits, and gas supply system problems, probably amounted to between one and two years of production at the capacity that would have been expected without the problems. The Brown Station Road problems might be considered "shakedown" in nature; such problems are generally most frequent in projects early on.

Performance after modifications. The combination of modifications to the gas cleanup train, the engines, and the gas collection system resulted in an integrated system that has subsequently worked very well.

Regarding electrical production, the engine-generators at full power produce a combined electrical power output of approximately 2,300 kW (nameplate rating of 2,550 kW, less a 10 percent reduction for CO_2 dilution with landfill gas). Averaged on-line availability of the three engines—when not limited by gas recovery system problems—is estimated by Curtis to be about 92 percent. Power purchase records for portions of 1988 (when the just-operational correctional complex was fully supplied by PEPCO utility power during the cited engine and other difficulties) indicate that baseload demand at that time was 800 kW, increasing to an averaged rate of 1,400 kW in midsummer in the daytime peak hours (defined by PEPCO as 8 hours per day). Available records are not in a form that permits precise determination of ongoing electrical use by the correctional complex; indirect evidence (see 5.1.9) suggests it is 1,000 or more kW baseload, and 1,700 kW summertime peak (peak use period defined by PEPCO utility as 860 hours per year). Whatever the exact use, County electric billing records show that the complex's power purchase from PEPCO was so low that the gensets unquestionably met more than 99 percent of the complex's needs (the County calculates 99.9 percent for the fiscal year ended June 30, 1990; PEPCO indicates the facility had purchased no power from October 1990 through June 1991)[4]. The current power supply reliability (with corrosion and other problems now under control) would appear in large part a function of conservative design, for example, the high redundancy inherent in three parallel engine-generators, the four engine-compressor units at the compressor station, and the high degree of parallel processing elsewhere in the system. The high level of on-line availability and reliability is also obviously a function of the efforts of Curtis, the operating contractor.

Regarding the heating system, the County reports advantages with running the heating and boiler system on landfill gas. The landfill-gas-fueled boilers are observed to be cleaner than oil-fueled boilers. Boilers are inspected once a year; maintenance is by contract to Professional Boiler Works, Inc., and to date very little maintenance has been needed. External fuel purchases are extremely low; based on outside fuel purchases and assumed annual displacement of the alternative use of 650,000 to 700,000 gallons of Number 2 fuel oil (see 5.1.9), the County calculates that landfill gas provided 99.3 percent of the fuel for heating and hot water needs in the fiscal year ending on June 30, 1990.

[4] Personal communication, David Leonard, PEPCO. July 1991.

5.1.5 Environmental/emissions

The County reports only that the facility complies with all federal, state, and local emissions regulations. The Brown Station Road landfill gas emissions that would otherwise occur through the surface of the fill are also being abated satisfactorily. Note that the Brown Station Road landfill is 15 miles from downtown Washington, D.C.; although the surrounding area is densely populated compared to most landfill sites, the County reports no odor complaints.

5.1.6 Operation and maintenance

The Prince George's County Brown Station Road facility, with multiple gas end uses, is one of the more complex U.S. facilities. The facility also has a more comprehensive maintenance contract than most, through Curtis Engine. The County has four separate contracts with Curtis; contract components cover maintenance of engine-generator sets, maintenance of the compressor station, overall operations, and compressor building maintenance. (Certain of the contract payments to Curtis are tied to attaining performance standards for the gensets.)

On-site energy equipment repairs and routine maintenance are performed by an on-site employee of Curtis Engine. Additional support is given as needed; Curtis estimates that 16 labor hours per week are spent on the energy equipment routine maintenance. Additional time and maintenance is spent on more significant repairs including parts replacements and overhauls. Curtis not only operates and maintains the energy equipment but also monitors and adjusts the gas field under existing contracts. Economic aspects of operation and maintenance are discussed in section 5.1.7.

Some of the engine operation and maintenance modifications by Waukesha and Curtis for landfill gas fueling are shown in table 7. These include higher oil and jacket water temperatures, frequent oil checks for contaminants and metal content as an indicator of wear, and others as shown. (Engine part modifications for landfill gas operation were discussed in 5.1.4.) Oil changes require two labor hours. Some of the other maintenance tasks are desiccant replacement and yearly replacement of the first finite filter element. The elements of other landfill gas fuel filters have been analyzed by their manufacturers but none have shown appreciable contamination in 2 years of operation.

To date, the gas transmission pipeline has needed no maintenance, which is a normal expectation with pipelines but also would appear to attest to the effectiveness of gas moisture removal and cleanup in the compressor station. One ongoing operational requirement for the pipeline is the "flagging" and location service to delineate the pipeline's location and prevent damage by excavation. This is a modest effort performed by an organization specializing in such work.

The prison heating system is reported to require no more maintenance than a system operating on pipeline gas. The operating history on landfill gas (since 1987) has, however, been relatively short; no further information is available.

TABLE 7. ENGINE OPERATING CONDITIONS ON LANDFILL GAS: BROWN STATION ROAD

Jacket temperature range: 220 to 230°F (104 to 110°C)
Oil temperature range: 190 to 195°F (87 to 90°C)
Oil used: Mobil Pegasus 446, TBN over 7.0
Oil Analyses: Every 350 hours
Maximum oil change interval: 350 hours for 5790GL (Genset engines) and 500 hours for 1197 (compressor engines)

5.1.7 Economics

A summary of the economic data is shown in table 5.6.5. and derivations (or origins) are discussed next.

Capital cost. The value which should be assigned to the capital cost of the facility is difficult to determine. The proceeds of a $6.1 million County bond issue were used in financing but what part of the bond proceeds was allocated to the initial construction is not clear (and how subsequent repair costs should be treated is an additional issue for capital costs). An estimate of $6.1 million for capital cost is used below; recognize, however, that this value is not certain.

Benefits. The gross cash benefits to Prince George's County consist of several components: the avoided costs of electric power and oil that would otherwise be required for the correctional complex, cash revenues from electric power export sales to PEPCO, and benefits from abatement of landfill gas emissions that would otherwise be experienced without the landfill gas energy use. These benefits are discussed next.

Although correctional facility power-use figures are not precise, available information does allow avoided electric power costs to be estimated, as set forth later in section 5.1.9. Calculations suggest correctional complex electrical savings of about $450,000 to $600,000 per year. An additional oil cost savings of another $450,000 to $500,000 per year is implied by the avoidance of an estimated oil use of 650,000 to 700,000 gallons per year (see 5.1.9). Through the contracts with Curtis, the County also avoids the costs it would otherwise experience for monitoring, adjustment, and repairs to the gas system, and blower operations and maintenance. These gas system costs are estimated based on similar operations elsewhere at about $50,000 per year.

Regarding sales to PEPCO note that, until 1990, power sales to the utility were based on fuel cost avoidance only, which resulted in very low revenues to the County from the electric power sales. With the improved generation reliability, and the resolution of other contractual issues (including mechanisms of PEPCO's cost recovery for the two-way interconnect), the terms of the facility's cogenerated power sale to PEPCO are much more favorable to the County; one improvement is a capacity payment (in addition to the normal payments per kWh) for summer peak hour exports that runs near $0.10/kWh. Data from the County[5] show sales of power to PEPCO in the range of $5,000 to $10,000 per month in early 1990 (until gas system problems were fully solved), but that are now increasing and closer to $20,000 per month. These figures would suggest power revenue from power export sales at a present annual rate between $200,000 to $300,000 per year.

As shown in table 8, the sum of the gross benefits, including both cash and "revenue equivalents" to the County, derived as above (without considering costs), would appear to be currently running between $1,150,000 and $1,450,000 per year.

Costs and debits. The operating costs and debits comprise various service contracts with Curtis Engine, a modest expense relating to the pipeline, and payments on bonds used to finance the facility. All of these expenses are discussed next.

Operating contract costs. As shown in table 8, the operating contract costs are currently about $400,000 per year (components were discussed briefly in section 5.1.6).

Pipeline Costs. The "flagging" service discussed earlier is stated to cost the County about $3,000 per year.

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5 Power sale and related records forwarded by Sheila Lanier, Prince George's County, to Don Augenstein, EMCON. June 1991.

TABLE 8. ECONOMIC DATA: BROWN STATION ROAD LANDFILL GAS ENERGY FACILITY

Estimated capital investment: $6.1 million	
Revenue, and avoided cost credits (thousands/year)	
Electrical costs avoided	$450-600
Heating fuel costs avoided	$450-500
Electric sales to PEPCO	$200-300
Gas System Credit	$50
Total credits (approximate range)	$1,150-1,450
Costs:	
Contracts, Curtis Engine	$399
Interest expense estimate (see text)	375-475
Pipeline-related (delineation)	3
Cost (approximate range)	$800-900
Lower bound, operating cash flow = $1,150-900 = $250,000/yr	
Upper bound, operating cash flow = $1,450-800 = $650,000/yr	

Bond interest costs. The facility was financed principally by a $6.1 million bond issue, marketed at the extremely favorable interest rate of 5.4 percent. To reflect bond retirement and rollover to refinancing at current rates, which could be 7 to 8 percent, and to reflect uncertainties in capital costs, interest charges would more realistically be expected to be about $375,000 to $475,000 per year. Further discussion is given in note 5.1.9.

Operating cash flow. The income less operating costs calculated and defined as above give rise to one possible definition of "operating cash flow," which (as shown in table 8) might be between $250,000 and $650,000 per year. A profit/loss calculation would require further assumptions in several areas, such as depreciation, and will not be attempted here; however, the current cash flow situation would appear favorable for the County. If repairs and equipment replacement costs do not exceed the operating cash flow, the long-term cash flow and profit situation will remain favorable.

5.1.8 Discussion

General performance. After the "shakedown" phase in which problems with the gas system and engine operation were resolved, the entire energy facility associated with the Brown Station Road landfill, including a cogeneration facility and space heating, has been functioning well. The energy equipment provides essentially all heat and power for the correctional complex, as was originally intended. Increasing operating experience and use of preventive maintenance, such as more frequent oil checks and changes, are reducing engine down time. The system is generating a positive cash flow, and the long-term prospects appear favorable.

Plans. The County's capital improvement budget is currently extremely limited; however, with increasing waste entering the landfill and expansion of the landfill gas system, more gas will become available. The County is beginning to consider options for which incremental cost may be acceptable and the return to the County favorable. These include installing three more gensets, in extending the pipeline to serve another County building complex, or both.

5.1.9 Calculation bases—energy use and financing

As stated in 5.1.4 and 5.1.6, available records do not allow correctional complex use rates to be determined directly. It has been necessary to estimate various energy use and economic parameters indirectly, and the estimates and their bases are set forth below.

Electrical power use and cost calculations. Regarding electrical power use, electrical billings over intervals when the correctional complex was wholly supplied by PEPCO (in 1988) showed power use shortly after startup to be about 800 kW baseload, up to a peak (noon to 8 p.m. weekdays) of 1,200 kW in winter and 1,400 kW in summer. The estimated output of the gensets, based on discussions with Curtis and other information, is 2,550 kW (nameplate) x 0.9 (correction for CO_2 dilution, landfill gas operation) x 0.90 (service factor), which for a 730-hour average month gives an estimated total production of 1,500+ MWh per month. The metering of correctional complex power use is not directly available; however, the evidence suggests that its power use is substantially above 1988 rates. Power export sales at full capacity by the facility of 300 to 600 MWh per month shown by 1990 records, combined with generation of 1,500+ MWh per month suggests time average correctional complex power use of 1,250+ kW in winter and 1,600+ kW in summer, and an annual time average near 1,400 kW. A possible conservative minimum schedule for power use and cost is shown in table 9.

This reflects, however, an annual time average power use of only 1,150 kW. Power use estimates (by the difference method above) suggest a possible annual time average use of as much as 1,400 kW and power costs nearer $600,000 per year. A range of $450,000 to $600,000 for avoided electric power costs has accordingly been used.

TABLE 9. POWER GENERATION AND REVENUE CALCULATIONS: BROWN STATION ROAD[1]

Summer Averages				
Interval Duration	hr/yr	Use, kW	$/kWh	$/yr
Peak	860	1,600	$0.04918	$67,671
Int. Peak	860	1,400	$0.04286	$51,603
Off Peak	1,880	1,000	$0.02790	$52,452
Winter Averages				
Peak	1,200	1,400	$0.04105	$68,964
Int. peak	1,200	1,200	$0.03576	$51,494
Off peak	2,760	900	$0.02322	$57,678

Demand charges

Summer: $9.50/kW x estimated 1,700 kW peak use x 5 months = $80,750

Winter: $3.90/kW x estimated 1,500 kW peak use x 7 months = $40,950

Total annual estimated cost = $471,562

1. All rate information was provided by Fred Leonard of PEPCO.

Heating oil use. The correctional complex's potential annual oil use would appear to be about 650,000 to 700,000 gallons per year (based on use rates while the landfill gas pipeline was not in operation). Aside from price jumps occurring because of the Persian Gulf situation, before early 1991 the County had been paying a price (with vendor markup) of about $0.60 per gallon in low-oil-use summer months, ranging up to about $0.80 per gallon in winter. About 2/3 of the oil would be used in the winter. An averaged overall cost of $0.70 per gallon multiplied by an estimated use of 650,000 to 700,000 gallons per year leads to an estimated cost saving of $450,000 to 500,000 per year, as stated in the text.

Bond financing. The cost component for bond financing can be calculated in different ways that result in different values for this cost. Based on an assumed capital cost of $6.1 million and a repayment schedule with provisions for full bond retirement in 10 years, the cost of a $6.1 million bond issue is about $805,000 annually (Watts, 1987). This includes complete amortization of the bond principal over 10 years, which is a higher than appropriate cost to include, since the energy facility's life will be much longer than the bond term. Interest charges on $6.1 million at 5.4 percent would be $329,000 per year; however if initial bonds at 5.4 percent are retired and refinanced ("rolled over") at a cost of 7 to 8 percent, bond interest cost will be $375,000 to 475,000 per year as stated; the range is rather wide to also reflect uncertainties attaching to the true capital cost.

5.2 Electricity Generation Using Cooper-Superior Engine at the Otay Landfill

5.2.1 Introduction and general overview

The Otay Landfill is located in Chula Vista, about 10 miles southeast of San Diego in San Diego County, California. The energy facility at this site is owned by Pacific Energy (PEn). It uses a Cooper-Superior engine-powered genset to generate electricity for sale to the San Diego Gas and Electric (SDG&E) grid. The facility exports a net output of about 1,700 kW at an averaged sale price with all utility payments, including capacity factored in, of around $0.09 cents/kWh, and typically obtains more than $1 million per year in gross power sale revenue. General information on the site and facility is shown in table 10. A photograph of the Cooper-Superior engine at the site (discussed in further detail later) is shown in figure 4.

5.2.2 Otay landfill and landfill gas system

Details of the landfill and landfill gas collection system are listed in table 11. The Otay landfill is a large canyon type fill, opened in 1966. PEn estimates that the landfill generates methane at a rate well beyond the needs of a single genset. The fill is currently served by wells extracting from only part of its volume.

TABLE 10. ELECTRIC GENERATING FACILITY AT OTAY LANDFILL

Location: Off Otay Valley road, 10 miles southeast of San Diego, California
Nature of Application: Electric power generation and sale to San Diego Gas and Electric Grid
Energy Equipment: Single engine-generator set, net output range 1,700 to 1,750 kW, powered by Cooper-Superior engine
Owner and operator of genset and auxiliary equipment: Pacific Energy
Landfill owner: San Diego County
Landfill operator: Herzog Contracting
Current tonnage in landfill: 6+ million tons
Gas collection system: Designed, owned, and operated by Pacific Energy

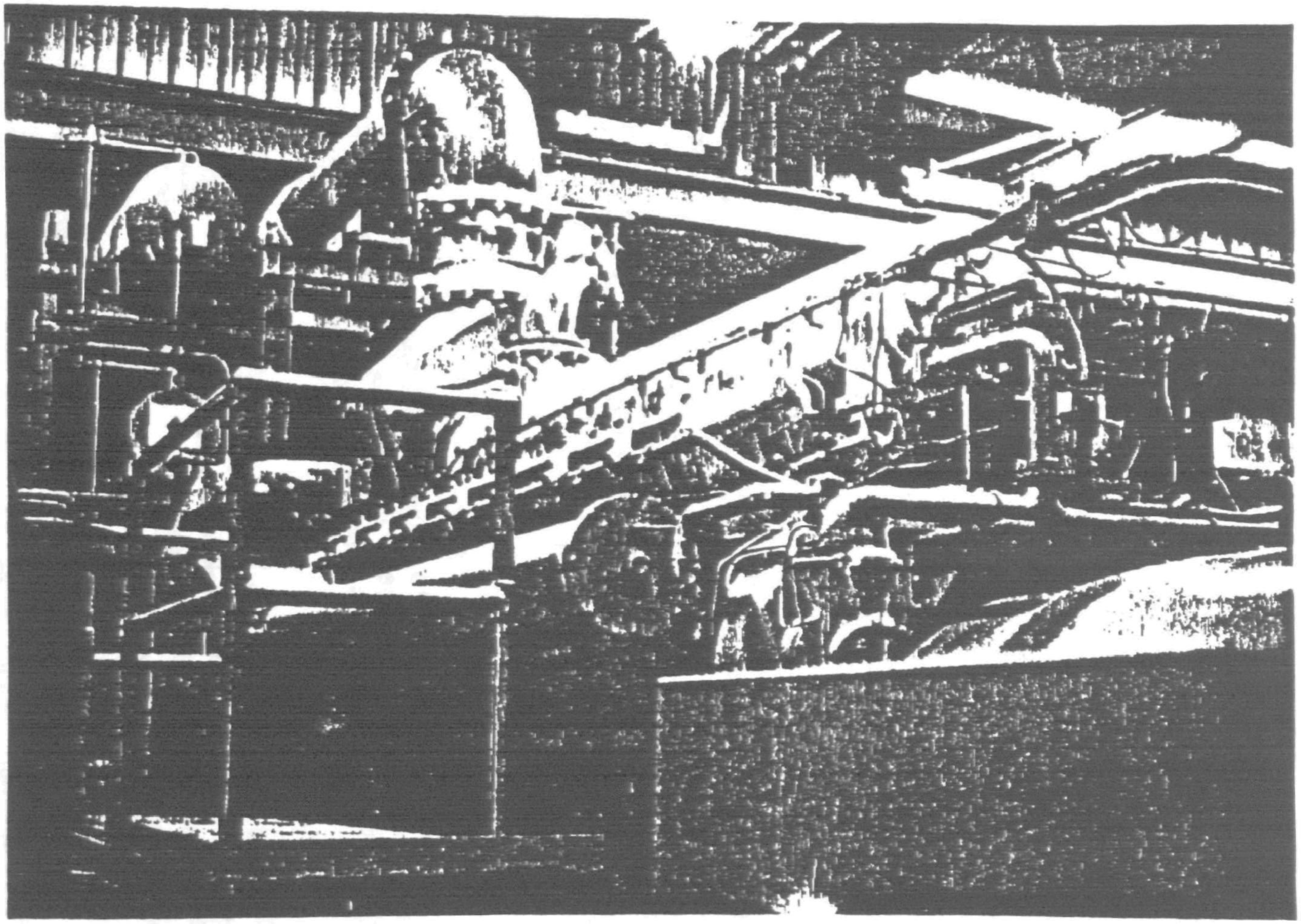

Figure 4 Cooper-Superior Engine: Otay Landfill Electrical Generating Facility

TABLE 11. LANDFILL AND GAS SYSTEM CHARACTERISTICS: OTAY

Landfill

Type: Canyon Fill

Date Opened: 1966

Waste in Place: 6 million + tons

Waste Fill Rate: 500,000 tons per year

Climate: Arid

Annual Rainfall: 10 inches

Final Cover Soil: Clay

Gas Extraction System

Type: Vertical wells

Number Active: 32 wells (early 1991)

Lateral/Main Header Pipe: Aboveground

Waste and Well Depth: Waste depth 90 to 150 feet; well depths approximately 75 percent of waste depths. Extraction zone: Bottom 40 feet.

Current Collection Rate: 650-700 cfm; 1,000,000 cfd (LFG)

Well Adjustment Protocol: To maximize Btu delivery to engine. Flow of wells over 50 percent CH_4 increased as needed; wells showing less than 50 percent CH_4 throttled.

Gas Analysis: 49-52 percent CH_4 by volume (gas entering plant is analyzed by Daniels automated gas chromatography system). Managed to maximize Btu extraction.

(PEn is now expanding the well system with the planned expansion of the energy conversion system to two gensets.) As the gas system was configured as of March 1991 it was reported to function well with standard well adjustment procedures to maximize total Btu delivery to the engine; these operating procedures resulted in a methane content reported at 49 to 52 percent with a gas flow of 980,000 cubic feet per day.

5.2.3 Gas preprocessing and energy plant equipment

A simplified block diagram of the facility's landfill gas processing and energy equipment is shown in figure 5. A list of gas preprocessing equipment and energy equipment is presented in table 12. PEn has also made available additional information on the Otay site; an energy equipment site plan is shown in appendix G and further equipment details are listed in appendix H. (This additional information was kindly provided when PEn made Otay available as a tour site for the Solid Waste Association of North America Landfill Gas Meeting, San Diego, March 1991.)

Landfill gas handling and preprocessing. Gas enters the plant from the collection system at a pressure of about -26 inches water gauge. It is initially cleansed of aerosols and particulates in a knockout tank, which is followed by a demister. Motive power for gas extraction and its further pumping through processing is provided by a two-stage, intercooled reciprocating compressor, located after the demister, which raises gas from the plant inlet pressure to about 90 psi, at the second stage outlet

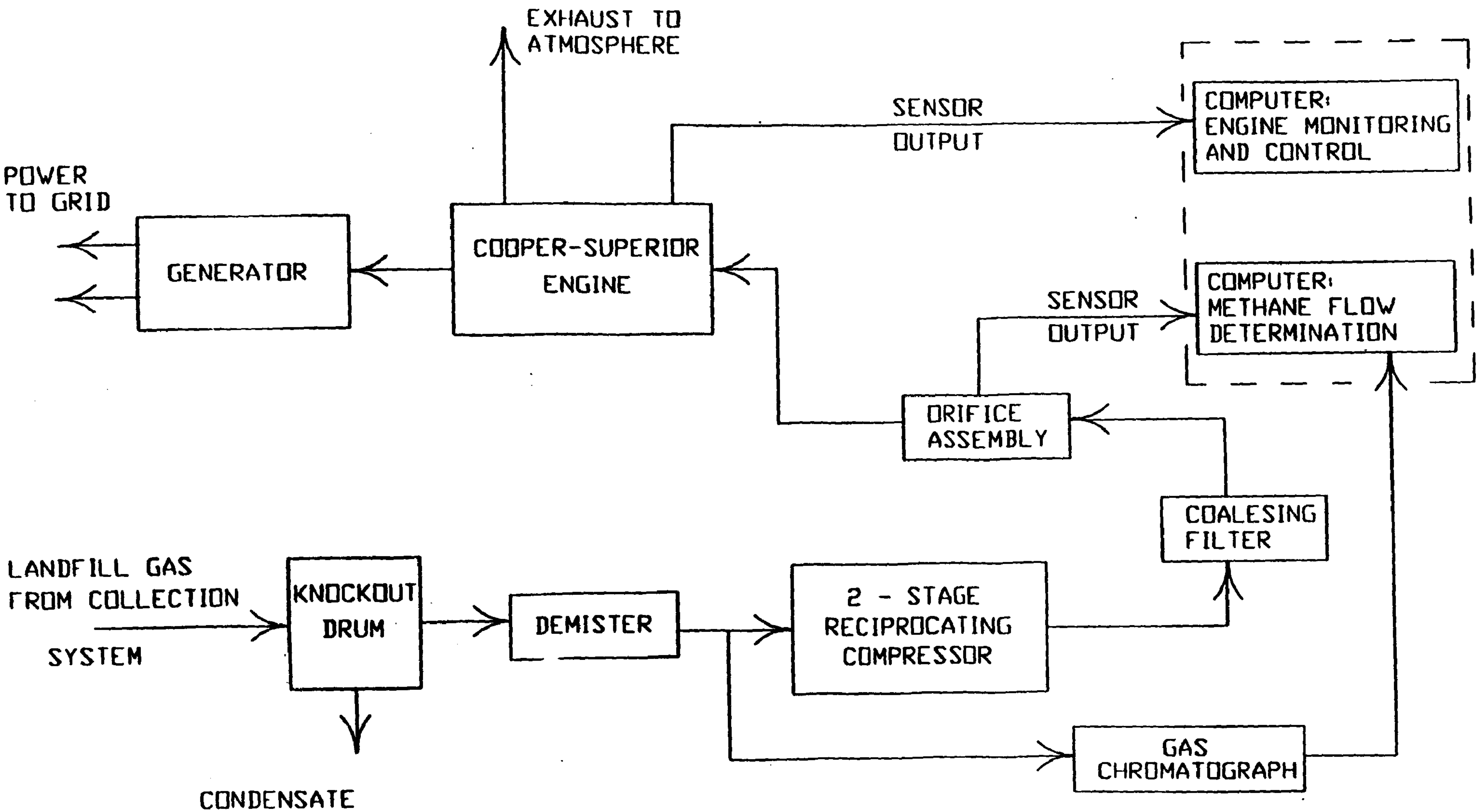

Figure 5
Electric Power Facility Based On
Cooper-Superior Engine At Otay Landfill
Simplified Block Diagram Showing Major Components

TABLE 12. DETAILS OF LANDFILL GAS PREPROCESSING EQUIPMENT AND ENGINE-GENERATOR AT OTAY LANDFILL

Gas handling and preprocessing

Condensate knockout tanks: Before first stage compression, and interstage

Demister: Model SWRT-3, fabricated by MPF, Inc.

Compressor: Ariel two-stage reciprocating compressor; inlet -20 to -40 inches w.g., outlet 90 to 100 psig

Filtration of compressed gas by King Tool model WW73T coalescing filter

Energy Equipment

Engine: Cooper-Superior 16SGTA, 16 cylinder, 900 rpm, turbocharged at 85-90 psig, lean-burn, gross shaft power rating 1,900 kW

Generator: Kato model A23277000 1,875 kW; 4,160 volt; 3-phase

Substation: Transformer stepup from 4,160 to 12,000 volts; owned by PEn

Monitoring

Gas flow rate by orifice meter

Gas composition by Daniels gas chromatograph system

Methane flow to engine computed by Kaye data computer

Engine condition and output by appropriate sensors

Over-all monitoring system vended by FLW, Costa Mesa, California

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(suitable for carburetion into the engine). Compressed gas at 90 psi then passes through a coalescing filter, and through a measuring station consisting of an orifice plate and appropriate pressure and other sensors. The measuring station sensor outputs connect to a flow computing system, discussed below. A small sidestream is withdrawn periodically, conditioned, and analyzed for methane content in a gas chromatograph, also discussed below.

Engine. The engine is a Cooper-Superior lean-burn model 16SGTA. Other engine characteristics are shown in table 12. The Superior engines were initially selected for earlier PEn sites because the manufacturer, Superior Engine Division of Ajax Industries, was willing to guarantee emission performance. Satisfactory initial operation, spare parts inventory considerations, and increasing familiarity with versions of the Superior engine led to their selection by PEn at subsequent sites including Otay.

The engine is housed in a building with much of the auxiliary equipment (layout shown in appendix G). Heat dissipation is a concern with such an engine enclosure; a large blower is used to circulate air through the section of the building containing the engine to dissipate heat within the building and help cool the engine. (The Otay site gets very hot in the summertime, increasing the heat dissipation concern.) Other features of the engine and associated equipment are shown in table 12 and presented in appendices G and H. The principal contractor involved in installing the facility was Equipment Associates Company (EACO). EACO packaged the genset. Installation and construction was by Modular Products, Inc., a former PEn subsidiary.

Monitoring and Control. A feature of interest at Otay (as well as other PEn sites) is the automated system that performs various monitoring and control functions. This monitoring and control system is similar to those often used at remote engine sites but has additional features specific to landfill gas operation. Landfill gas composition, as was noted earlier, is monitored by an automated gas sampling and chromatography system (Daniels Corp), which samples and measures gas stream component concentrations at predetermined intervals. Landfill gas flow is determined based on an orifice plate system (PEn indicates that orifice meters are preferable to turbine-type meters, which tend to foul and lose calibration frequently). The orifice system measures temperature, absolute pressure of the flowing gas, and pressure drop across the orifice and delivers these data to a computer (Kaye Data); the computer uses these and the gas composition data to calculate methane flows under standard conditions. In addition to giving methane flowrate information (which with power output allows engine efficiency to be calculated) this sampling procedure detects changes that may indicate problems (such as oxygen in the gas, which could indicate line leaks).

The system obtains indications of the "health" of the Cooper-Superior engine by measuring several parameters; for example, it measures the cylinder head temperature of each cylinder (a low temperature would suggest that a cylinder was misfiring). Engine-threatening or other serious malfunctions activate an automated shutdown sequence.

Data logging and processing for all of the above are performed by a minicomputer (Kaye Data), capable of a range of processing and logging options. As an example of the system's capabilities, it can be programmed to provide a readout of the previous 32 hours of engine performance based on engine power output and other key operating parameters. This monitoring ability is one feature that allows PEn to operate the system with low operator labor.

Performance/availability. Overall performance and availability have been excellent since the system's startup in 1986. PEn states that the engine has typically been on-line more than 90 percent of the time in years since startup in 1986. The down time, or the remainder of the time, is stated to be principally for scheduled maintenance. Production was 93 percent and 97 percent of full rated capacity in 1989 and 1990, respectively.

The gross output of the genset, without considering parasitic loads, runs around 1,875 to 1,900 kW. The parasitic loads, most notably the compressor/turbocharger at about 100 kW, but also blowers, lights, and other uses, reduce output so that a net of 1,700 to 1,750 kW is exported to the grid. This net exported output still represents a heat rate range stated by PEn to be between 12,000 and 14,000 Btus (higher heating value) of landfill gas per kWh exported.

5.2.4 Environmental/emissions

Source tests are conducted on the engine consistent with the requirements set by the San Diego County Air Pollution Control District. The results of one such test are shown in table 13. The emissions of the engine are within the limits set by the permit, also shown in table 13. A second engine would also be permitted at its expected emission level and is being installed. The current air regulations do not allow a third engine to be installed at this time.

5.2.5 Operation and maintenance

PEn's automated system for monitoring and controlling the engine and other key parameters (e.g., gas flow, composition) typically allows the plant to be operated with one operator for a standard work week of 40 hours. The operator's duties also include monitoring and adjusting the gas field. Additional staff support may also be given as needed.

Maintenance items for the engine include weekly monitoring of oil for contaminants. The gas compressor is inspected every 6 months. Oil is changed approximately every 2,000 engine operating hours, a task that takes about 4 hours. Engine overhauls, consisting of upper and lower end, are performed

TABLE 13. RESULTS OF SOURCE TEST ON COOPER-SUPERIOR ENGINE AT OTAY LANDFILL.

Tests conducted by volatile organic compound testing, San Diego, California, October 20 to 27, 1987. Standard operating conditions, full load. Stack gas flow 5,680 scfm. Several runs averaged.

For reference: Exhaust O_2 = 6.8 percent by volume, CO_2 = 13.4 percent by volume

Component	Concentration in exhaust gas, ppm
NOx	370
CO	448

Non-Methane Hydrocarbons: 0.0769 lb/bhp.hr

Allowable engine emissions limits, Otay landfill:

Component	One engine	Two engines
NOx, lb/yr	93,195	179,887
CO, lb/yr	154,413	288,306
NMOC, lb/yr	39,925	79,850

approximately every 8,000 hours. Other significant plant maintenance items are gas compressor maintenance once per year, and various degrees of engine servicing at 500, 1,000, and 5,000 hours, and annually.

5.2.6 Revenue and cost items

Economic data made available for the Otay facility are summarized in table 14. The power sale contract (under terms of a variant of the California Public Utility Commission's Interim Standard Offer Number 4) with SDG&E is favorable. Although power sale payments actually vary with time and other factors, the contract's features are such that when all utility payments are considered, the averaged per-kilowatt hour price paid for a continuous, constant power stream sold to SDG&E would be about $0.09 cents per kWh. This energy revenue includes capacity payments that are received by PEn in addition to the per kWh payments (note that these contract terms were finalized in the mid-1980s and contracts available currently would be less favorable). Thus, with power production typically over 90 percent of full-rated capacity, the Otay facility revenue at an output of 1,700+ kW is high. Gross electric power sale revenues in 1989 and 1990 were $1.2 million and $1.3 million, respectively. This revenue is distributed to several participants; its allocation is not available but is distributed to royalty recipients, as well as PEn.

5.2.7 Discussion

Performance effects attributable to landfill gas. Engine power output is somewhat reduced compared to nameplate rating or pipeline natural gas. The compression of landfill gas from atmospheric pressure to the carburetion pressure of the lean-burn turbocharged engine (an energy demand not present with pipeline gas) is a parasitic load probably reducing the net efficiency of the genset by several percentage points.

Regarding engine life and wear, PEn maintenance precautions involving frequent oil checks, other monitoring, other engine maintenance, and engine overhauls every 8,000 hours appear to prevent any landfill-gas-contaminant problems from becoming severe.

TABLE 14. REVENUE AND OTHER ECONOMIC DATA: OTAY ENERGY FACILITY

Averaged payments per kWh, 1990: $0.09
Total capacity payments, 1990: $240,000
Total gross electric revenue, 1990: $1.3 million
Averaged payments per kWh, 1989: $0.089
Total capacity payments, 1989: $240,000
Total gross electric revenue, 1989: $1.2 million
Gas system capital investment (excluding energy plant): $300,000
Estimated capital investment for energy equipment: Not available (confidential)

Lessons learned and other comments. PEn did not identify any issues that could be categorized as "lessons learned" from its Otay site. This is not unexpected since lessons learned from PEn's operation at other sites were presumably applied at Otay to forestall problems. PEn staff did point out, however, that emission standards changes, including those occurring "after the fact" of permitting and start-up, are posing serious uncertainties and cost impediments to projects such as Otay; such costs must be borne by cogenerators like PEn since there are no means for passing them through to power purchasers.

Plans. Because landfill gas is available and the permit allows for it, PEn is installing a second genset at Otay. (Note added as of September 1991: the installation has now been completed.) It would consider a third, if gas proved available and the permit could be modified to allow it.

Summary. PEn is a significant operator of landfill-gas-fueled electrical generating facilities. It has developed site selection criteria and operational practices that appear to serve well. Economic performance appears to have been good.

5.3 Electric Power Generation Using Waukesha Engines at the Marina Landfill

5.3.1 Introduction and general overview

The Marina Landfill is on Del Monte Road 1 mile south of California State Highway 1 in Marina, California. The facility at the site employs two Waukesha-engine-powered gensets for electric power generation and sale to the Pacific Gas and Electric Company (PG&E) grid. The gensets generate a net total of approximately 1,150 kW for export to PG&E. A photograph of the trailers housing the gensets is shown in figure 6.

With initial genset startup in 1983, this was one of the first landfill gas-to-energy projects to operate in the United States. General information on the site is summarized in table 15. The initial capital investment in the system, exclusive of the extraction system was about $1.3 million in 1983 dollars. Gross revenue from electric power sales within the past few years, including capacity payments, has typically been about $360,000 per year.

Current operating arrangements are also indicated in table 15. The Monterey Regional Waste Management District (MRWMD) owns and operates the engines, receiving the profit (or any potential loss) from engine operation. The Monterey Landfill Gas Corporation (MLGC) operates the gas system,

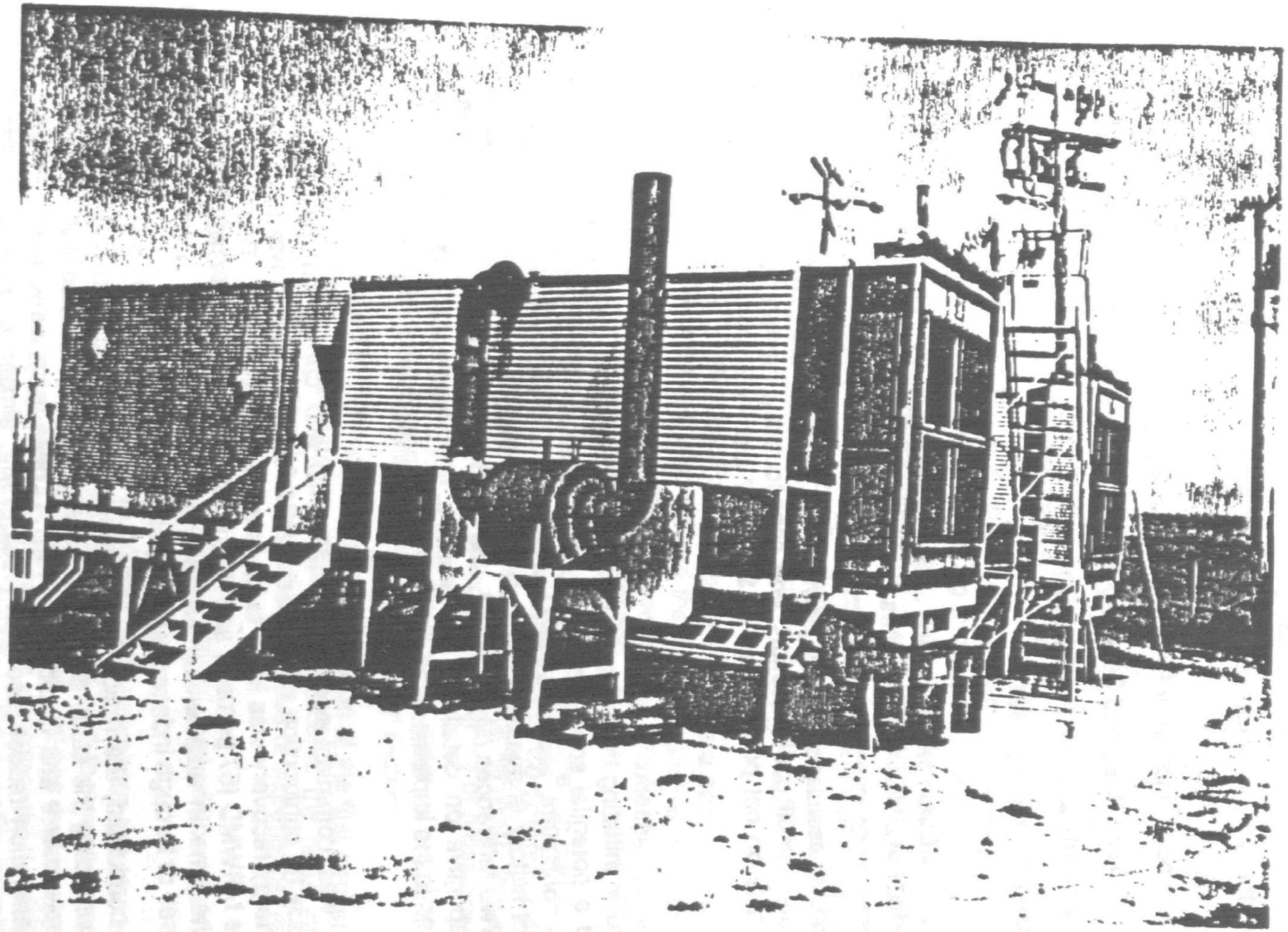

Figure 6 Marina Landfill Electrical Generation Facility. Each trailer encloses a Waukesha L7042 GU naturally aspirated engine and 650 kW generator. External cylindrical housing holds catalyst bed.

TABLE 15. ELECTRIC GENERATION AT THE MARINA LANDFILL

Site: Marina, Monterey County, California

Nature of application: Electric power generation and sale to grid.

Energy equipment: Engine-generator sets powered by Waukesha Engines, system designed by Perennial Energy

Owner and operator of Energy Equipment: Monterey Regional Waste Management District

Startup dates of gensets: December 1983 (first) and February 1984 (second)

Landfill Owner: Monterey Regional Waste Management District

Current tonnage in landfill: 4 million tons in early 1991

Fill rate: 850 tons/day.

Gas collection system: Designed by EMCON; owned by and operation/monitoring by Monterey Landfill Gas Corporation (MLGC), a subsidiary of EMCON Associates

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with additional gas system operating assistance being provided by MRWMD staff. The MRWMD's benefits come from power revenue, landfill gas collection, and consequent emission abatement. The MLGC's benefits come from a royalty on net power sales of $0.00667 per kWh and tax credits on the delivered gas.

5.3.2 History of project

Two factors were particularly helpful in initiating this project. The MRWMD directors and staff were aware early that landfill gas represented a potential source of energy and revenue for the district. EMCON Associates (EMCON), the district's consultant, also had early involvement and background in landfill gas energy issues. A complete project history is available because of the principals' documentation of the project in the technical literature. Two references (Myers, 1987, and Van Heuit and Pacey, 1986) present the MRWMD and EMCON's perspective on details of the project's implementation and subsequent experience to 1987. The major steps in the implementation of the project included the following.

Initial steps:

1. An initial feasibility study was commissioned by the MRWMD and carried out by EMCON in 1981. This study (in conjunction with gas extraction tests discussed next) showed that landfill gas energy recovery was likely to be feasible and profitable. This study was supported by the MRWMD (67 percent) and PG&E (33 percent). The PG&E utility was interested at the time in augmenting electric generating capacity in its service area (whether by itself or through independent suppliers).

2. Gas extraction tests were conducted, the major ones being a two-well test that had been conducted in 1977 (preceding the study discussed above) and another two-well test completed between September 9 and October 16, 1981. These tests, as well as the projections of a gas generation model (see Van Heuit, 1987; similar to models discussed in EMCON, 1982) indicated that sufficient gas was available to allow economic electric power generation. All extraction tests and gas generation projections were performed by EMCON.

3. EMCON suggested—with concurrence from PG&E—that using the gas to fuel electric power generation for sale to PG&E was the best alternative.

(Note: The further negotiating steps, with engine suppliers, exemplify complexities that can be encountered in attempts to implement an energy system. The brief summaries presented below that suggest their complexity, and additional detail can be found in Myers, 1987.)

4. Negotiations for an energy conversion system proceeded initially with Engine Power Company of Stockton, a large, well-established, and experienced vendor of engine-generator sets. Engine Power considered including financing with the complete package. In 1982, however, Engine Power elected to terminate negotiation due to financing considerations.

5. American Mobile Power was the next potential vendor of a complete package. It obtained an Authority to Construct from the local air quality district, and a power sales contract from PG&E during this negotiation. American Mobile Power could not, however, obtain the required financing. It terminated negotiations shortly thereafter.

6. The next step, undertaken to reconfirm the basis for the project and reassure potential participants, including those providing project financing, was a longer term gas test performed by EMCON in 1983, with sixteen 50-foot-deep wells to fuel a portable engine. These tests again showed the availability of adequate gas.

7. Proposals to the MRWMD were concurrently considered for energy packages and financing, which were made by Cambrian Energy Systems (Pacific Lighting) and Gas Recovery Systems (Genstar). A proposal including financing was also made by Palmer Capital (Palmer).

8. After extended negotiation, Palmer was selected as a partner. Perennial Energy, now of West Plains, Missouri, also offered the package judged best, to design, install, and maintain two trailer-mounted gensets powered by Waukesha 12-cylinder, 7,040 cubic-inch engines, for an initial cost of $1,300,000.

9. Financing for the energy facility was arranged by Palmer, in part through the formation by individual investors of the Marina Landfill Gas Corporation (MLGC), and in part through a loan from the Bank of New England. The MRWMD leased the gas rights to MLGC in exchange for royalties of at least 12.5 percent of gross power sales to PG&E.

10. Further emission-related issues were resolved in order to obtain a permit to operate from the Monterey Bay Unified Air Pollution Control District.

Steps 1 through 10 resulted in the installation and operation of the first genset in December 1983, and the second in February 1984. The installation can be considered the result of persistence by technically aware participants (though it cannot be said to be the result of experience, since no one had experience at that time).

Further occurrences after startup are of historical interest, and will be referred to in the later economic discussion:

11. In 1986, largely due to a decline in PG&E power payments, but also because of tax law changes, Palmer Capital donated its stock and sold the gensets to the MRWMD for $500,000. MLGC retained ownership of the gas and gas system (through 2001). As owner of the gensets and PG&E power-sales contract, the MRWMD now receives revenue from the sale of electricity; royalties are paid to MLGC. As a further informational note to the sequence of steps above, MLGC was purchased by EMCON in 1988 (for $200,000).

5.3.3 Landfill and landfill gas extraction system

Details of the landfill and landfill gas system are given in table 16. The Marina Landfill is a large landfill, termed an "area fill" type by the MRWMD (it could also be termed a cut and fill), in operation since 1966.

It had received about 4 million tons of predominantly residential municipal waste by early 1991. The depth of fill in areas from which gas is extracted ranges up to 90 feet.

TABLE 16. LANDFILL AND GAS SYSTEM CHARACTERISTICS: MARINA

Landfill

Location: North of Marina, in Monterey County, California; on Del Monte Road, 1 mile south of California Highway 1

Type: Area Fill

Date Opened: 1966

Waste in Place: 4 million tons

Waste Fill Rate: 260,000 tons per year

Total Fill Area: 490 acres

Area Now Filled: 90 acres

Climate: Mediterranean

Annual Rainfall: 11 inches

Daily Cover Soil: Sand/silt

Intermediate Cover Soil: Sand/silt

Final Cover Soil: Sand/silt with 1 foot of clay

Gas Extraction System

Type: Module 1 - vertical wells. Module 2 - horizontal trenches

Number Active Collection Units: Module 1 - 12 vertical wells; Module 2 - 7 horizontal trenches, Module 3 - none

Collection Unit Piping: PVC

Lateral/Main Header Pipe Material: PVC, aboveground

Collection System Details:

- Vertical wells: 18-inch diameter, 40-50 feet deep, permeable material and slotted pipe below 20 feet, bentonite seal at top of permeable material and at surface
- Horizontal trenches: 2 feet deep by 3 feet wide backfilled with 1 1/2 inch gravel, embedding 6 inches PVC solid pipe, no seal at joint (gas enters loose joint), 6-ounce geotextile cap over gravel.
- Pipe slope at minimum of 2 percent

Current Collection Rate: 580 cfm (LFG), or 850,000 cfd (LFG)

Adjustment Protocol: Keep methane concentration at 55 percent + since only about half of estimated gas availability is extracted.

Gas Analysis: Methane analysis by portable thermal conductivity based gas analyzer

The initially installed portion of the landfill gas system consists of 16 vertical extraction wells (first used for tests as described in Van Heuit and Pacey, 1987). Horizontal trenches have been installed subsequently as newer areas are constructed. The MRWMD has installed seven horizontal trenches in Module 2 and two horizontal trenches in the lower portion of Module 3. The extraction well system is maintained by MLGC, with assistance from the MRWMD.

The Marina landfill generates methane at a rate in excess of genset needs. Extant wells and connected horizontal trenches could provide significantly more gas than is required for the engines; in general, the field functions well, with few adjustments. Some wells are left wide open; wells yielding less than 50 percent methane, as occurs occasionally, are throttled back. The few other adjustments include periodic replacement of flex hoses and resloping of aboveground gas lines so that condensate drains properly. Condensate accumulation problems have occurred from time to time, and further condensate traps are being installed in response to needs.

5.3.4 Gas preprocessing and energy plant equipment

A simplified block diagram for the energy facility is shown in figure 7. Major gas preprocessing equipment and energy equipment items are listed in table 17.

Landfill gas handling and preprocessing. The features of the gas collection system were noted above. The equipment for landfill gas handling and preprocessing at Marina consists solely of a fiber filter medium (size cutoff not available) in a small housing, and two small Hauck blowers, one for each engine. The blowers and filter were engineered by Perennial Energy. This is considered very limited processing, based on practices elsewhere.

Engines. Each of the two gensets is powered by a Waukesha model L7042GU 12-cylinder engine. The noteworthy feature of this engine model is that it is naturally aspirated. As discussed in section 3, this means that the engine is carbureted at a near stoichiometric fuel-to-air ratio (the mix can be very slightly fuel rich) and that the fuel-air mix enters engine cylinders at near atmospheric pressure. This contrasts with the use of lean-burn engines, which are turbocharged, at most other U.S. sites where landfill gas is used to power IC engines. Further characteristics of the engines are shown in table 17.

The gensets are housed in two trailers, as originally designed by Perennial Energy. The trailer roofs were designed to be removable for maintenance. The trailers were originally mounted on railroad ties, but these were replaced in 1985 with a steel frame after vibration and settlement problems attributable to the railroad tie mounting occurred.

A catalytic converter, mounted on the outside of the trailer, is used to reduce NO_x, CO, and NMOCs in the engine exhaust. This catalyst (performance is discussed later), is a 3-way type very similar to that used for automotive exhaust purification. After trials with various forms of catalyst, the MRWMD has settled on a Riley-Beard catalyst on a bead-type support.

Performance/availability issues. Over-all performance and availability have been good since the first genset was installed in 1983. The MRWMD states that an average availability of more than 80 percent was obtained for the first 3 years of operation (Myers, 1987). One way in which the genset service factor may be calculated is to divide the actual yearly power output sold to PG&E by the number of kilowatts that could potentially be obtained at 1,150 kW with no downtime in a full year. Service factors calculated on this basis (for this report) from yearly kilowatt totals were 81 percent in 1987, 89 percent in 1988, and 82 percent in 1989 (the service factors might be slightly different if calculated on run time). The MRWMD has calculated a service factor, based on run time, of 80.4 percent for 1990. The most serious outages were a bearing failure in 1985, believed to be caused by the inadequacies of the railroad tie supports for the genset trailers, and an outage in 1990, not related to any fundamental genset problem in 1990, due to a supplier shipment of the wrong maintenance replacement parts.

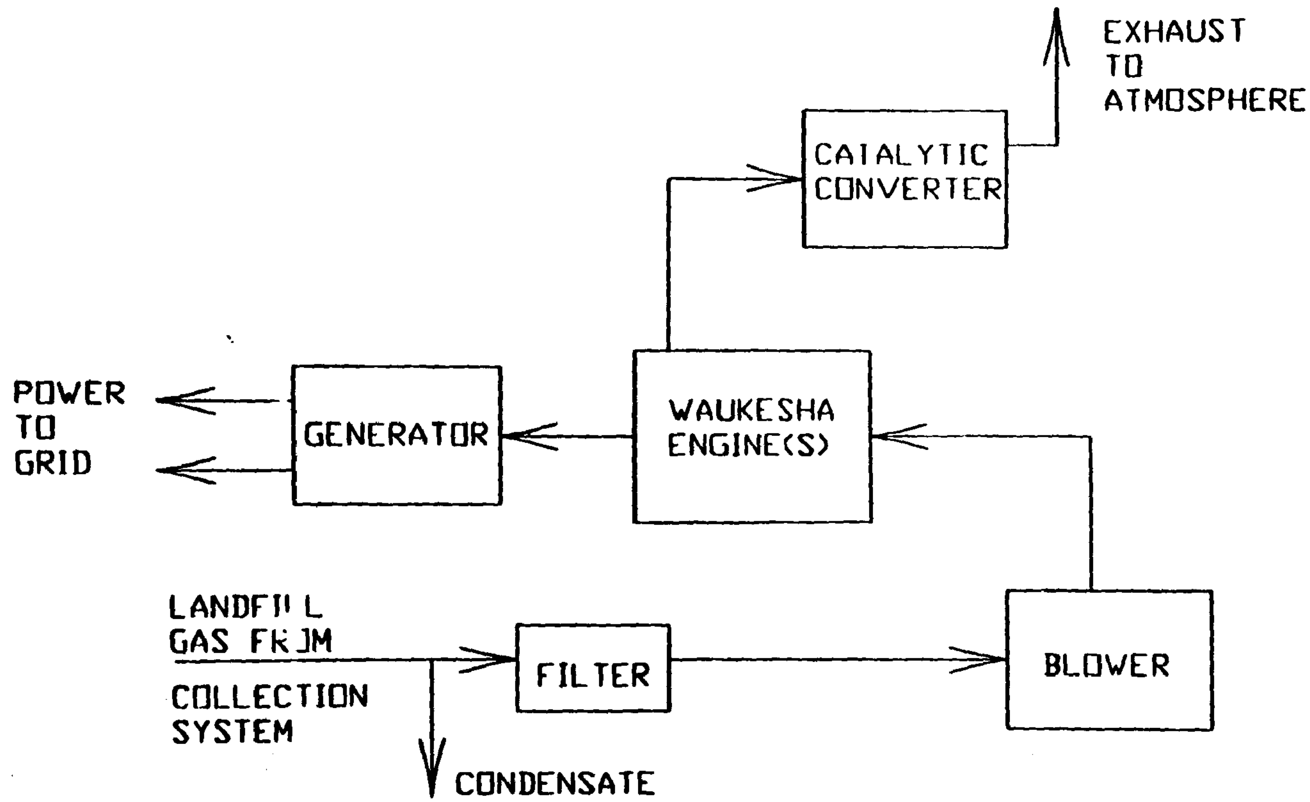

Figure 7
Electric Facility At Marina Landfill
Simplified Block Diagram Showing Major Components

TABLE 17. DETAILS OF LANDFILL GAS PREPROCESSING EQUIPMENT AND ENGINE-GENERATOR SETS AT MARINA LANDFILL

Gas Preprocessing

Blowers: Two Hauck, 4 hp, model TBA-16-3-T-1 (one per engine)

Custom filter unit: Cartridges in 2-foot diameter by 4-foot high housing; designed by Perennial Energy, West Plains, Missouri

Energy Equipment

Engines: Waukesha L7042 GU engines, naturally aspirated

Generators: Reliance model VHP 7100 G. Approximate maximum output 650 kW, normal output range 560 to 600 kW

Engine operation and maintenance data:

- Oil used is Mobil Pegasus 446 high alkalinity, 850 hours between changes
- Maintained 1983-88 by outside contractors, 1988 on by MRWMD
- Catalyst system: Riley-Beard catalyst. Catalyst in annular bed between inner and out cylinders; 4 inch catalyst bed depth, area of catalyst bed approximately 12 square feet

Other than bearing failure and spare parts problems, the 15 to 20 percent downtime has been for routine maintenance and a variety of other causes worth noting briefly. The engines have tended to overheat when ambient temperatures are over 70°F and winds are blowing from east to west (counter to the prevailing wind direction, which means the radiator is on the lee side). Some fatigue-related engine problems are said by Marina staff to be developing. The closeness of a hot exhaust pipe to the cylinder head was at one point a source of problems, as was the noted original mounting of the trailer enclosures on support beds of railroad ties. Some of the problems, as well as repair difficulties, appear to be the result of the deliberate decision to save money on the genset design. Given the reasonable on-line performance to date, however, it is not clear that spending more money initially on the gensets would have been highly cost effective.

Fuel efficiency. The calculation of engine fuel efficiency at Marina presents some uncertainties. (With a more than adequate gas supply—and a facility that is generator limited—there is currently no incentive to maximize, or even closely determine, the fuel efficiency of the engines, which are running at less than their greatest possible output.) One uncertainty that can be mentioned is just how much fuel is actually entering the cylinder on each stroke. Waukesha expects that the heat rate of this particular engine on pipeline natural gas at full power would be near 10,745 Btu/kWh shaft power[6]. It can only be said that, by various indicators (which are approximate), the Marina engines' fuel use would appear to be very substantially higher, when expressed as Btu/kWh sold to PG&E. This would in part reflect the expected generator inefficiency in converting engine shaft power to electric power.

Catalyst. Catalyst life, even with frequent dust removal and washing, has, until recently been short, about 3 months; catalyst replacement has therefore represented a significant expense. Catalyst

6 Personal communication, Walter Pontell, Waukesha Engine Division, Waukesha, WI. June 1991.

problems are considered to be landfill-gas specific, and generally due to attack from small quantities of HCl and HF formed during combustion (section 2). Recent changes to a higher alkalinity engine oil appear to be substantially increasing catalyst life. One additional problem identified by the operator is that under certain operating conditions, the catalyst temperature can increase, inactivating the catalyst (apparently by sintering). The operator states that, with the existing catalyst temperature sensing arrangement, damage appears to be done by the time the temperature rise is noted.

Specifics of catalyst performance in reducing emissions are presented next.

5.3.5 Environmental/emissions

The genset engines are emission tested consistent with requirements set by the Monterey Bay Unified Air Pollution Control District. Available results from three exhaust emissions tests are shown in table 18; these test results illustrate aspects of catalyst performance.

The emissions of an engine with an exhaust catalyst are a function of (1) the functional ability of the catalyst to reduce NO_x and oxidize other exhaust gas components and (2) the operating parameters, particularly carburetion, of the engine. Ideally, the engine carburetion will be close to stoichiometric, with just enough air to burn the fuel. The catalyst will cause the reducing gases (CO and NMHCs) in the exhaust to reduce NO_x to N_2, leading to substantial reduction of the reducing gases and NO_x in the exhaust gas. The emission performance of the engine in this (rather ideal) case can be good; without going into detail, note that the results (shown in table 18) of the first engine test (September 12, 1989) show pollutant emissions below any existing California or U.S. standards. On the other hand, deviation of the air/fuel mix from stoichiometric can lead to formation of more NO_x than can be reduced or more reducing compounds than can be oxidized; any of these conditions, or catalyst inactivation (which has

TABLE 18. SUMMARY RESULTS: EMISSIONS TESTS ON MARINA ENGINES

(Output at 560 kW, average of three 1-hour tests for each date shown)

	Exhaust component ppmv (as emitted)	Gm/ bhp hr	Measured lb/hr	Permitted lb/hr[1]
<u>September 12, 1989, engine M2</u>				
NOx	10	0.04	0.07	3.12
CO	78	0.21	0.34	11.45
TNMHC	<10	<0.01	0.02	3.12
<u>September 20, 1990, engine M2</u>				
NOx	2.5	0.01	0.02	3.12
CO	518	0.6	2.52	11.45
TNMHC	<10	<0.01	<0.01	3.12
<u>October 20, 1990, engine M1</u>				
NOx	25	0.13	0.22	3.12
CO	2211	7.31	12.10	11.45
TNMHC	0.02	0.01	0.02	3.12

1. Assumed as half of total permitted emission limits for two engines operating simultaneously

been a major problem at Marina), can cause the emissions to rise to unacceptable levels. This is illustrated by the last test of engine M1 on October 20, 1990, which shows elevated CO levels that might be due to an overly fuel-rich carburetion condition. (Note that only one tested emission level in table 18 can be considered to exceed permit condition, and that only slightly: October 20, 1990, for CO.)

As engine loads increase, at generator outputs above 600 kW, tests have also shown (detail omitted) that emission levels tend to increase significantly, even with the catalyst. Thus emissions have sometimes been limiting facility electric output; the degree of limitation will decrease if catalyst performance can be improved. The permit to operate currently limits each generator's output to 640 kW.

5.3.6 Economics

As a preface to a discussion of economics, some background on ownership should be noted. At the original purchase price of $1.3 million and with initial financial arrangements, MLGC's break-even level for power sale to PG&E was about 4 cents per kWh (total of all utility payments including those for capacity, averaged per kWh). The power sale contract (which had, among other features, a variable price component relating to the purchase price PG&E must pay for oil/gas fuel) was such that power purchase prices could and did fall below this in 1986. The system was at that point transferred to the MRWMD for $500,000 (Myers, 1987). With this transition, the arrangement changed from one in which the MRWMD received a royalty of 12.5 percent on gross power sales, with minimal risk, to one in which the MRWMD operated the system and bore the entire responsibility for profit and loss. The power sale royalties to the MRWMD, by years before the sale, were $33,084 in 1983 to 1984; $93,989 in 1984 to 1985; and $44,672 in 1986. The revenues beginning in 1987 (which are best expressed as net of various expenses, and with qualifiers), after the sale, are discussed below.

Revenues from sale of electric power to PG&E consist of payments that vary on a price schedule by time of day for kilowatt hours delivered, and also a capacity payment with this particular contract (the capacity payment reflecting, in essence, savings relating to generating capacity the utility does not need to build). Appendix I shows a typical schedule of sale prices per kilowatt hour for specified time periods, ranging from $0.028 to $0.034 per kilowatt hour in mid-1990. One feature of the contract to note is that PG&E may elect not to buy power for up to 600 hours within any given year. The MRWMD continues, however, to operate the engines and provides power to the PG&E grid, because of the environmental benefits at Marina, even when PG&E elects not to pay. The capacity payment, which reflects the higher value of generated power in meeting needs at times of high demand, is important and normally provides a large portion (about 35 percent) of the total gross electric revenue; it amounts to additional revenue in the range of $0.015/kWh. Capacity payments (by calendar year) at Marina were $138,000; $140,000; $130,000; and $13,700 in 1987 through 1990.

A problem with maintenance spare parts and down time in 1990 caused most of the 1990 capacity payment to be deferred until certain probationary conditions imposed by PG&E were met; these conditions were in fact met and the 1990 capacity payment was collected in 1991 (in addition to the normal 1991 capacity payment that was earned in 1991).

Table 19, derived from figures provided by Marina, shows gross electric revenues and operating expenses for the three Marina fiscal years beginning in the year July 1, 1987, to June 30, 1988. (1990 to 1991 figures are not available; the 1990 to 1991 revenue would be low as noted because of the deferral of capacity payment; this is not a permanent problem). The operating expenses include factors such as operating labor, maintenance, and royalties, but exclude capital-related charges such as interest on debt and depreciation. The table does not include a one-time tax payment of $82,000 that was peculiar to Marina's circumstances and would not be a normal expense. The operating revenue for the MRWMD is calculated in table 19 as the difference between the gross revenue and operating expenses. The average operating revenue, as defined above for the three typical MRWMD fiscal years 1987 to 1988, 1988 to 1989, and 1989 to 1990, has been near $166,000 per year. It is very important to note that this operating revenue specifically excludes the debits that would be due to financing charges, and depreciation necessary to reflect the eventual need for equipment replacement.

TABLE 19. ECONOMIC DATA FOR MARINA LANDFILL GAS ELECTRIC GENERATION FACILITY

Initial capital cost of facility (1983): $1,300,000

Purchase price paid for facility by MRWMD in 1986: $500,000

"Typical" per kWh price schedule for power sale: See appendix I

Calculation of operating revenue (see text) by year of operation:

Year	1987-88	1988-89	1989-90
Gross revenue	$369,328	$360,825	$360,927
Less:			
GASCO royalties	$56,125	$55,349	$50,755
Repairs, maintenance	$126,909	$85,672	$87,080
Salaries/fringes	$6,000	$36,000	$45,000
Misc outlays	$4,081	$13,407	$25,265
Net Operating Income	$176,213	$170,468	$152,827

MRWMD has paid off all capital costs with revenues, and now owns the system free and clear. It receives the benefit of landfill methane emission abatement in those areas where gas is being extracted. While the benefits are obvious and the MRWMD nets income, its capital cost has been well below the typical capital cost for similar equipment. Revenues would need to be higher than at Marina to assure acceptable economics if the equipment cost were more typical. Some further discussion of economic issues is presented in 5.3.8.

5.3.7 Operation and maintenance

Supply and other costs were listed above. The naturally aspirated engines can operate with only moderate attention. Operation and maintenance labor-hours are estimated at about 40 hours per week. These labor needs actually vary, given that a team of maintenance workers may be needed on occasion, while at other times very little operator attention may be needed. Parts cited as routine maintenance needs are head gaskets and cylinder heads. Marina staff rebuild the cylinder heads on site.

5.3.8 Discussion

Performance effects attributable to landfill gas. The impact of using landfill gas on the performance of the system, compared to what might be expected with the same system's performance on natural gas, seems minor. The Waukesha L7042GU engines would be expected to produce 1,173 horsepower, or 875 kW on pipeline gas.[7] Even allowing for an engine shaft power loss of 10 percent, due to dilution by CO_2, maximum engine shaft power output on landfill gas could still be expected to be about 790 kW. The generators however limit each genset's output to 600 kW, so CO_2 dilution is not the limiting factor on power.

Given the problems encountered at other sites, and the very limited gas preprocessing at Marina, the absence of engine problems attributable to landfill gas contaminants at Marina over an 8-year period is notable. None of the problems mentioned earlier with the engines/gensets relate specifically to contaminants. The Waukesha factory representative indicates that operation and maintenance of the

7 Personal communication, Walter Pontell, Waukesha Engine Division, Waukesha, WI. June 1991.

engines should be close to identical at their somewhat reduced load compared to full load operation, other things being equal[7]. It can be speculated that the lack of problems could be attributable to cleanliness of gas at the Marina site, or possibly some feature of stoichiometric-burn naturally aspirated engines that renders them less susceptible to landfill-gas-contaminant related problems.

Catalyst performance issues. Catalysts' performance has in general been poor when they have been used with landfill gas fueled stoichiometric burn IC engines in the past (Jansen, 1986). Low levels of HCl and HF combustion products typically attack catalysts and support, causing malfunction. This was the case until recently at Marina, as the catalyst bed had to be cleaned about once each month, and the catalyst had an extremely short service life (very rapid breakdown) versus that with normal natural gas applications. The adoption of a high-alkalinity oil whose ash is reported to coat the catalyst appears to be benefitting catalyst life (as might be expected chemically). As of the site visit, the most recent batch of catalyst had been performing well, with only limited dust removal, for more than 7 months. This performance, if sustainable, would reduce catalyst related costs and help make stoichiometric burn approaches such as are used at Marina more attractive.

As a summary comment on the potential of catalysts, the Marina results suggest promise for their use in reducing emissions of naturally aspirated stoichiometric burn engines. Their successful application would enable greater use of these naturally aspirated engines with their attendant operating simplicity. As seen at Marina, however, the various problems with catalyst attack, mixture control, and other areas are not yet completely solved.

Economic issues. As noted in 5.3.6 the Marina facility generates a positive cash flow, but it was acquired by the MRWMD for $500,000, a capital cost that was about 40 percent of the initial market cost. By way of comparison, costs of a brand-new facility with characteristics similar to the Marina facility can be roughly estimated to be between $1.5 and $2.5 million, or roughly $1,000 to 2,000/kW (excluding gas extraction). Depending on depreciation figures and financing costs (which are to some extent a matter of judgement), a new facility in this cost range would be losing a moderate amount of money by selling power to the grid with the actual power sale arrangement. The basic, overall import is that Marina, with its existing revenue structure, would not be implemented today because of economics. Facility expansion is precluded by economics and also emission constraints although the gas is available.

Lessons learned and other observations. Marina staff note that access to the current trailer is difficult for certain types of repair and maintenance. The lack of "as-built" drawings has also posed a problem in some areas, notably generator repair. Relating to overheating problems, Marina staff have suggested that these could have been reduced if roof-mounted radiators had been used.

Plans. With recent improvements in catalyst performance, a third engine installation might be permitted by the Air Pollution Control District; the gas is available and the MRWMD would attempt to install a third engine if it could obtain a satisfactory power sale agreement. PG&E now has a surplus of generating capacity, however, as well as low-cost power being vended to its grid. The chances of obtaining an agreement providing satisfactorily high power revenue in the near term appear small. (The PG&E utility does, however, anticipate a need for additional capacity later in the 1990s.)

5.4 Electric Power Generation Using Gas Turbines at Sycamore Canyon Landfill

5.4.1 Introduction and general overview

Sycamore Canyon landfill is located near San Diego, California. The facility at this site uses two Solar Saturn recuperated gas turbines to generate a total of slightly more than 1,300 kW (net) for export sale to the San Diego Gas and Electric grid. As of the site visit (March 1991) the facility was owned and operated by Solar Turbines (Solar). A photograph of the building housing the turbine generators is shown as figure 8.

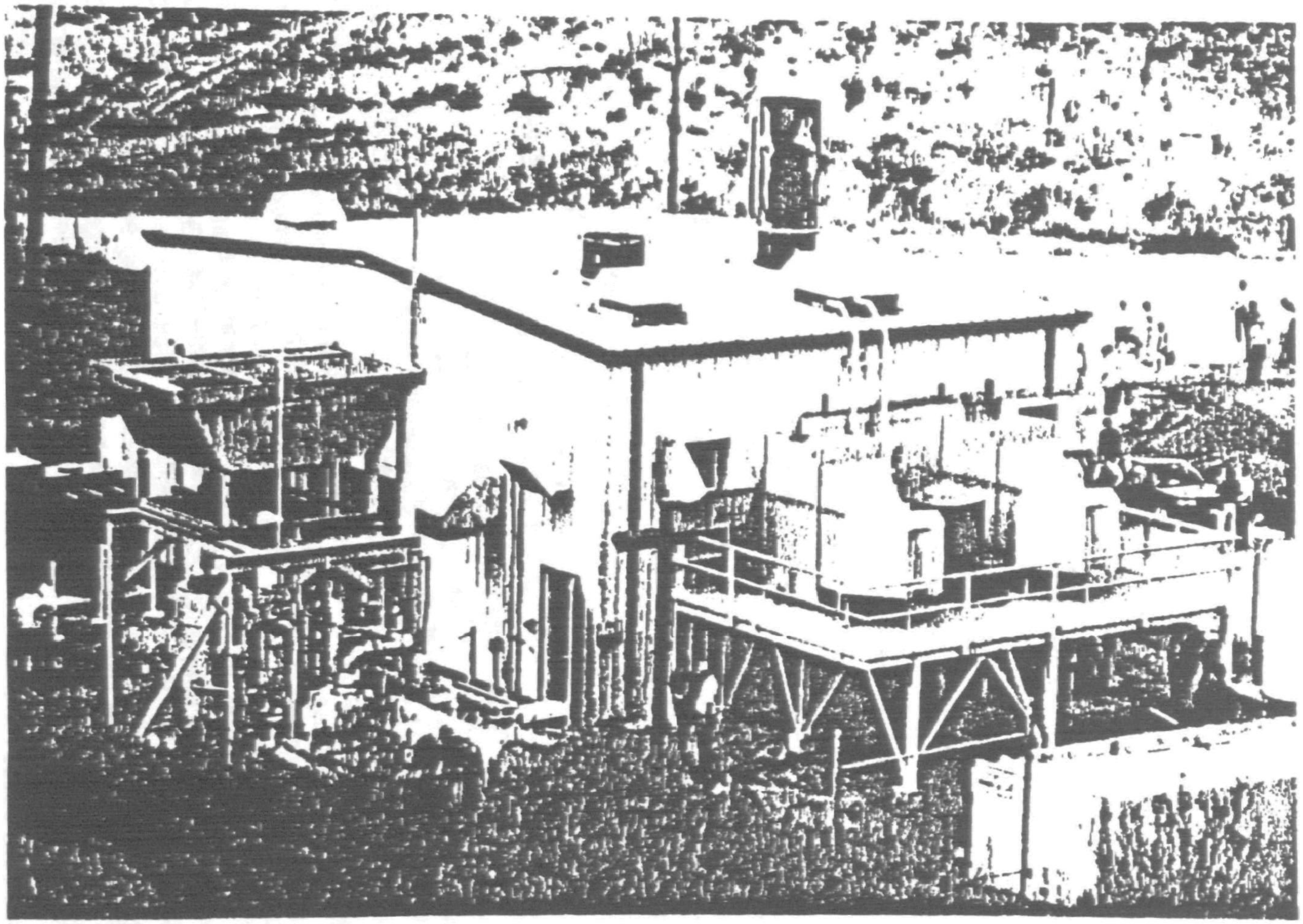

Figure 8 Sycamore Canyon Electrical Generation Facility: Building Houses two solar gas turbines, and associated generators.

General site information is summarized in table 20. The turbine generating system has been operating since 1989. Solar states that capital investment for this system was about $4 million; gross revenues from electric sales are currently running at about $650,000 per year. Solar operates and has maintenance and profit-and-loss responsibility for the generating plant. Solar also operates the landfill gas system. San Diego County has overall responsibility for operation of the landfill.

Further specifications and details on the energy application and operations at this site follow, beginning with the history of implementation.

5.4.2 History of system implementation

Solar staff indicated that motivating forces to embark on this project included (1) an acceptable projected return (2) a desire to sell Solar equipment (3) a desire to further expand their operating experience base on landfill gas (4) ample gas supply projected based on the tonnage of waste in place, and expected at closure, and (5) the project's contract to sell power at a favorable rate to the local utility under California's Standard Offer number 4. The convenience of the site's location to Solar's manufacturing facility in San Diego also appears to have played a part in the decision.

Solar was able to negotiate mutually agreeable terms with the owner of the landfill, San Diego County. The County was willing to have the energy system installed under terms where Solar operated the energy system, was responsible for maintenance of the gas collection system, and the operator and the County were provided a royalty from electrical sales of approximately 8 percent of net.

5.4.3 Landfill and landfill gas system

Details of the landfill and landfill gas system are given in table 21. The initial landfill gas system was designed and installed by GSF Energy. Current vertical well pipe is carbon steel, rather than the usual plastic; steel well pipe was selected based on its ability to better withstand compressive and shear forces from waste subsidence in this deep landfill. Wells are equipped with zinc anodes for corrosion protection. Collection well laterals are both below and aboveground, and the main header is aboveground. Solar states the length of the collection well lateral piping is about equally divided between above and below ground piping.

The 9 million tons of waste in place are expected to generate methane at a rate exceeding the gas needs for the two turbines operating at full power (which would together be expected to consume about 450,000 scf of methane per day). Despite cover soil that is reportedly relatively porous, standard well adjustment procedures produce an acceptable gas supply for the facility. The system has experienced

TABLE 20. GENERAL INFORMATION: SYCAMORE CANYON LANDFILL GAS ENERGY FACILITY

Location: 15 miles northeast of the City of San Diego, in San Diego County, California

General description of energy application: Electric power generation, sale to utility grid

Generating plant: Based on two Solar Saturn recuperated gas turbines, nameplate rated at 933 kW each, with other standard Solar components

Startup date: Early 1989

Owner and operator of energy equipment: Solar Turbines

Landfill owner and overall operator: San Diego County

Current and projected tonnage in place: 9 million tons in 1991, 30 million tons at closure in 1998

Landfill gas collection system: Vertical well, operated by Landfill Energy Partners

TABLE 21. SYCAMORE CANYON LANDFILL AND GAS SYSTEM CHARACTERISTICS

Landfill

Location of landfill: Mission Gorge Road, San Diego County

Type of landfill: Municipal waste, largely canyon fill

Date opened: 1962

Tonnage in place (early 1991): Approximately 9 million

Scheduled tonnage at closure: 30 million in 1998

Climate: Semi-arid, rainfall about 10 inches per year

Cover soil material: "porous," permeability not stated

Acres/Acres filled: 530/390

Gas System Characteristics

Designed and installed by: GSF Energy

Operated and monitored by: Landfill Energy

Number of vertical wells: 50

Depth of wells: Approximately 80 feet (variable)

Depth of permeable zones in wells: Bottom third to two thirds

Current gas collection rate: 1.2 million cubic feet of landfill gas per day

Gas analysis: Three times weekly by gas chromatograph for methane

Procedure for well adjustment: Wells below 50 percent methane, throttled; flow rate of those above 50 percent, increased as appropriate.

few problems from "overdrawing" (air infiltration through the surface associated with a high rate of extraction), although it has had some problems associated with piping leaks. Leaks can result in problems caused by gas being diluted with air. To forestall such problems, an oxygen sensor at the plant triggers an alarm when the oxygen concentration exceeds 1.8 percent, and a system shutdown when oxygen concentration exceeds 3.6 percent.

5.4.4 Plant equipment: Gas preprocessing and energy

A simplified schematic of the energy equipment is shown in figure 9. Gas preprocessing equipment and energy equipment characteristics are shown in table 22.

Landfill gas handling and preprocessing. The features of the gas collection system were noted above. The equipment for further landfill gas handling and preprocessing within the plant was engineered by Solar. Gas enters the plant through the gas system main header. A vacuum of 2 inches mercury, or about 25 to 30 inches water column, is typically maintained at the point where the main header enters the plant. Vacuum for gas extraction from the landfill, and motive power for initial pumping of landfill gas within the plant, is provided by an oil-flooded screw compressor within the plant (see flow schematic and table 22). Immediately on entering the plant, and before the compressor, this raw gas passes through a

TABLE 22. GAS PREPROCESSING AND ENERGY EQUIPMENT AT SYCAMORE CANYON

Landfill Gas Preprocessing Equipment

In-line liquid removal by "slug catcher": Modified tank (see text)

Landfill gas flow monitoring: Daniels orifice

Landfill gas oxygen content measurement (see text): Teledyne fuel-cell based oxygen meter

Gas filtration for particulate and water removal: Peco coalescing filter (4 inches w.g. pressure drop), 10 micron cutoff, and vane-type coalescer

Landfill gas compressor: Solar/Howden oil-flooded two-stage, -28 inches w.g. to 150 psi

Energy Equipment

Overall generator set description: Saturn T-1300

Turbine subcomponent of generator system: Solar Saturn, Model GSC 1200R, 1988 model year.

Generator subcomponent: Marathon, 950 kW

Other electrical power system components: Standard Solar engineered package

device to intercept free liquids ("slug catcher"). This is essentially a baffled tank designed to intercept quantities of condensate liquid that build up or pool at low points in the gas system and may "very occasionally" mobilize in the gas system and move with the flowing gas as a large "slug" to the plant. Any such liquid must be intercepted to prevent damage to plant equipment. After the slug catcher, the gas passes consecutively through a coalescing filter and vane scrubber, where aerosols and particulates down to 10 microns are removed. The volumetric flow rate of the gas is measured by a Daniels orifice flow meter. The scrubbed landfill gas undergoes two stages of compression in an oil-flooded screw compressor (see block diagram in 9); gas exits the first compressor stage at about 50 psig and the second stage at about 150 psig. The compressed gas temperature when it leaves the second stage is about 200°F. The gas contains entrained oil from the screw compressor, which is then removed by a knockout vessel and coalescing filter. Gas then passes to a cooler, where water is condensed out. The gas is then reheated to 35 to 40°F above the dewpoint before passing through a gas pressure regulator and then to the turbine. This final reheat is needed to produce the dry gas required for trouble-free operation of the gas turbine fuel metering system.

Turbomachinery. The two Saturn turbine powered gensets (table 22) are adaptations of standard Solar designs for power generation at sites such as offshore gas platforms. Plant thermal-to-mechanical efficiency and electric power generating efficiency are improved through recuperation of inlet air with turbine exhaust, as is commonly practiced. The need for operator attention is kept fairly low by using a process monitoring and control system developed by Solar. This system acquires, conditions, and processes data and has capabilities including process control, operational data logging, and remote data acquisition. The remaining equipment is also standard. Other specifications and characteristics of the turbines and generating equipment are presented in table 22.

Performance/availability Issues. Solar states the net heat rate for power generation by the facility to be about 14,500 Btus/kWh based on gas lower heating value, which translates to about 16,000 Btus/kWh based on the landfill methane's higher heating value. The overall plant generating efficiency with this gas turbine is lower than would be obtained on "normal" pipeline natural gas fuel; this is mostly attributable to

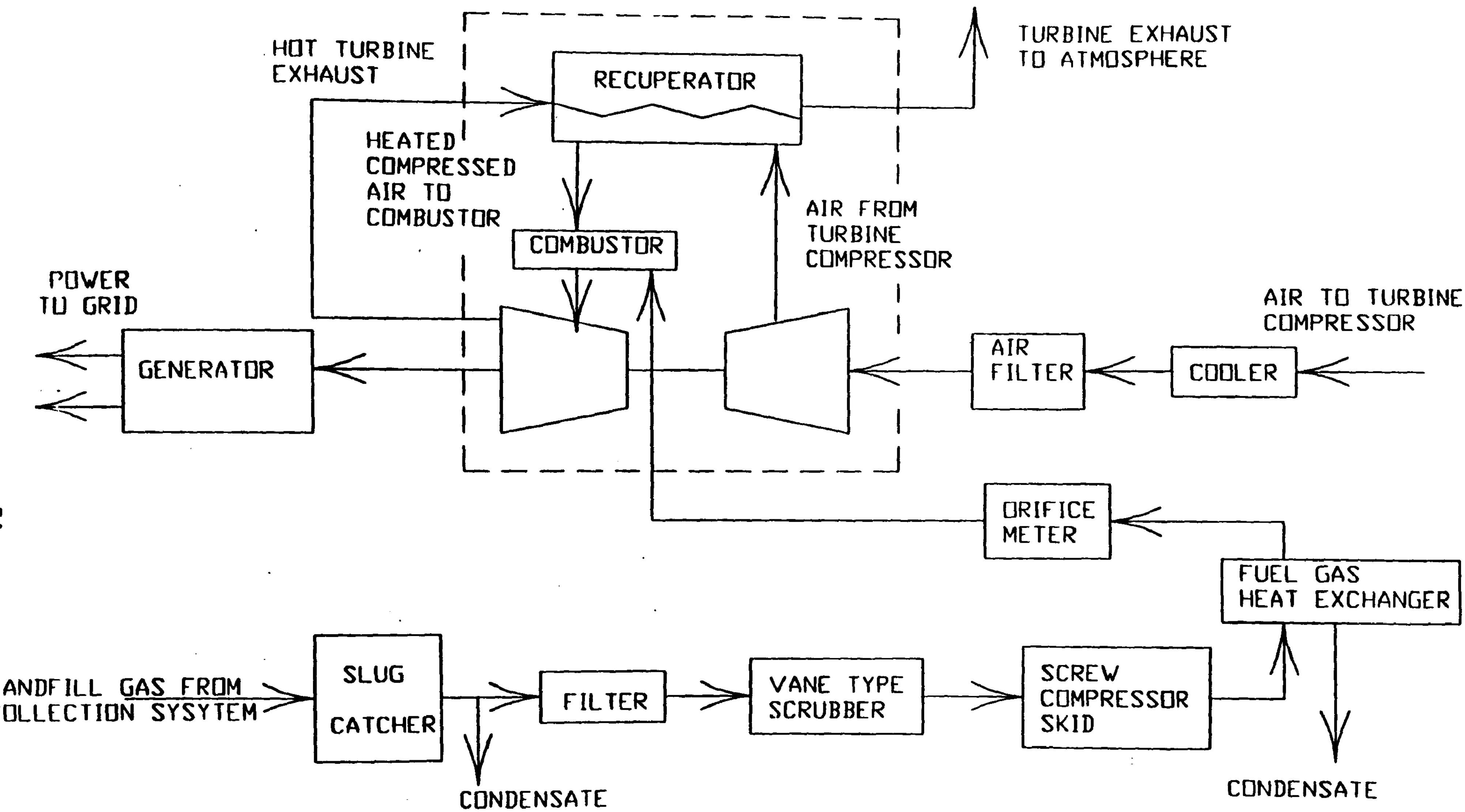

Figure 9
Gas Turbine / Electric Power Facility At Sycamore Canyon
Simplified Block Diagram Showing Major Components

parasitic compression work required for landfill gas. (Pipeline gas fuel is normally available under pressure, and requires no further compression when used as a turbine fuel; however, landfill gas at atmospheric pressure requires additional work to compress to 200 psi, as discussed in earlier sections.) Efficiency may be slightly further reduced because less air recuperation can be practiced; air subject to recuperation is a lower fraction of the total feed gas entering the turbine than would be the case with natural gas fuel. (The carbon dioxide portion of the landfill gas makes up a greater portion of the diluent gas and, with current practice, it is not recuperated.)

These factors (predominantly gas compression) add to the parasitic load (200 kW) and reduce the efficiency, resulting in a net output of 1,325 kW.

As normally constrained by blade temperature limits, the turbine's maximum power output increases with the mass of gas that the turbine can take in; this mass and thus the power output increases as the temperature of the gas intake decreases. The entering combustion air is therefore precooled on hotter days by passing it through an evaporative cooler. Necessary on-site makeup water for this cooler is being provided by Culligan Water until permanent city water lines are installed.

Availability. Turbine availability may be expressed as hours of on-line availability in response to need. It can also be compared to that for the same turbine operating on a normal 100 percent available natural gas supply. Solar states that an availability of 90 to 93 percent with landfill gas would be expected. Such availability with normal natural gas is stated by Solar to be 98 percent, since downtime for gas turbine maintenance is typically low. The additional downtime with landfill gas is attributable to landfill gas field supply problems and modifications of that part of the plant specific to landfill gas processing.

5.4.5 Environmental

Source test of generating facilities are required under rules of the San Diego Air Pollution Control District. Two source tests have given actual exhaust gas composition results as shown in table 23.

Permitted emission levels were not obtainable. Solar states "Emission levels were consistent with current production gas turbines. This has not limited energy recovery."

5.4.6 Economics

Economic factors are summarized in table 24. From limited data provided by Solar, economic return appears to have been lower than desirable to date. It must be emphasized that these economic indices are for a limited term, and specific to this site and situation. The continuing installation of such turbines at landfills by others (particularly Waste Management, Incorporated) attests that such turbines can be economically attractive.

TABLE 23. SOME EMISSION TEST RESULTS AT SYCAMORE CANYON

	Test date	
	Feb. 2, 1989	Feb. 3, 1989
Percent O_2 (for reference):	17.51 percent	17.56 percent
NO_x:	49.07 ppm	40.70 ppm
CO:	4.71 ppm	4.68 ppm
NMHC:	3.5 ppm	1.7 ppm
SO_2:	0 ppm	0 ppm

TABLE 24. ECONOMIC DATA: SYCAMORE CANYON GENERATING FACILITY[1]

1. Capital investment for energy facility: $4,000,000
2. Gross revenues from electric sales (as operated)

1989:	Sales	$400,000
	Capacity payment	$150,000
	Total	$550,000
1990	Sales	$500,000
	Capacity payment	$150,000
	Total	$650,000

3. Standard Offer number 4 electric sales contract—80 percent fixed, 20 percent floating. Further details not available from Solar.
4. Typical operating and maintenance (not including gas): $400,000/year

   Operator 40 to 48 hours/week (cost included as component of above)
5. Total gas cost (includes royalties and other costs): $350,000/year
6. Gas royalties to County: Approximately 2.5 percent of net electrical sales
7. Landfill gas system operation and maintenance costs of approximately $15,000 per month

1. All figures provided by Solar

5.4.7 Operation and maintenance

Day-to-day operations of the generating plant (excluding service visits and operation of the gas collection system) are carried out by one site operator, and Solar reports an operator labor requirement of 5 to 6 days per week. The principal maintenance items were stated to be lubricating oil, spare parts usage and overhauls.

5.4.8 Discussion

Performance differences attributable to landfill gas. Solar reports that efficiency is reduced by 13 percent from the efficiency that would be obtained with the same turbine on more conventional pipeline gas or distillate fuels. This loss is almost entirely due to the greater parasitic load posed by landfill gas compression.

Other problems or malfunctions of the energy equipment, specifically attributable to landfill gas, have not been seen. (Such problems have been seen and addressed with similar turbines at other sites and were discussed in 3.1.5. The gas preprocessing system at Sycamore as designed by Solar appears to be adequate to prevent these problems). One problem that can be considered landfill-gas specific is posed in gas preprocessing by the "slugs" of liquid, which occasionally mobilize and reach the slug catcher at the plant.

Plans. A larger "slug catcher" is planned to further reduce the possibility of damage due to liquid entering the plant. (While this modification is judged desirable by Solar, it also must be noted that this plant has suffered no damage from this source to date.) As of the site visit, Solar stated that there were no plans for facility expansion.

Lesson learned. Other than the need to protect the plant with a larger "slug catcher," Solar did not identify any lessons learned regarding the energy plant itself.

Note added: In 1992, the facility was reported by Solar as sold to Laidlaw Gas Recovery Systems, Incorporated[8].

5.5 Landfill Gas Fueled Boiler: Raleigh, North Carolina

5.5.1 Introduction and general overview

In Raleigh, North Carolina, a boiler fueled by about 900 cfm (1,300,000 cfd) of landfill gas generates steam at a rate typically near 24,000 pounds per hour to meet the needs of a pharmaceutical plant. The energy conversion system uses gas collected from a municipal landfill (Wilder's Grove). It consists of a pipeline transmission system, a boiler (Cleaver-Brooks), and the building housing it at the pharmaceutical plant (Ajinomoto). Basic features of the facility are listed in table 25. A photograph of the boiler (more details are presented later) is shown in figure 10. Capital investment for the pipeline, pumping station, and boiler totals approximately $900,000. Gross revenue from steam sales is running in the range of $450,000 to $500,000 per year.

Participants in the project include Natural Power, Inc. (Natural Power), which had major responsibility for implementing the project; Raleigh Landfill Gas Corporation (RLGC), an affiliate of Palmer Capital, which installed the gas collection system and provide gas to the facility; Ajinomoto USA (Ajinomoto); and the City of Raleigh (City), which owns the landfill. The ownership and operational arrangements are also summarized in table 25. Natural Power revenues are derived from the sale of steam to Ajinomoto. Royalties from the steam sale revenues are paid to the City of Raleigh. Landfill gas used in making steam is purchased by Natural Power from RLGC. The City also gains environmental benefits from operating a gas system at its landfill, and RLGC benefits from tax credits on the landfill gas sold to Natural Power. Ajinomoto is supplied steam for its pharmaceutical plant operations at a competitive cost. System performance to date appears satisfactory for all participants.

5.5.2 History of project implementation

The history of this project provides another example of complexities that can be encountered in attempts to find appropriate landfill gas energy uses, and then to implement a system. Securing needed landfill gas rights was difficult; much further analysis and investigation was also involved in the selection of an energy application and user. Events that occurred along the way to implementation of the current energy system included the following.

Negotiation for landfill gas rights. The City initially recognized the energy and income potential of gas from its landfills, and offered gas rights to its landfills by auction in 1984. Natural Power was one of six bidders for these rights. The award of rights was based largely on the royalty offered by bidders on landfill-gas-derived energy income, and rights were awarded to another bidder, promising the highest royalty. About 2 years were required to establish that the bid winner (now out of business) did not have the necessary resources to implement an energy system; the total delay engendered by these events was well over 2 years.

8 Personal communication, R. Aucskiewicz, Solar to D. Augenstein, EMCON, February 1992.

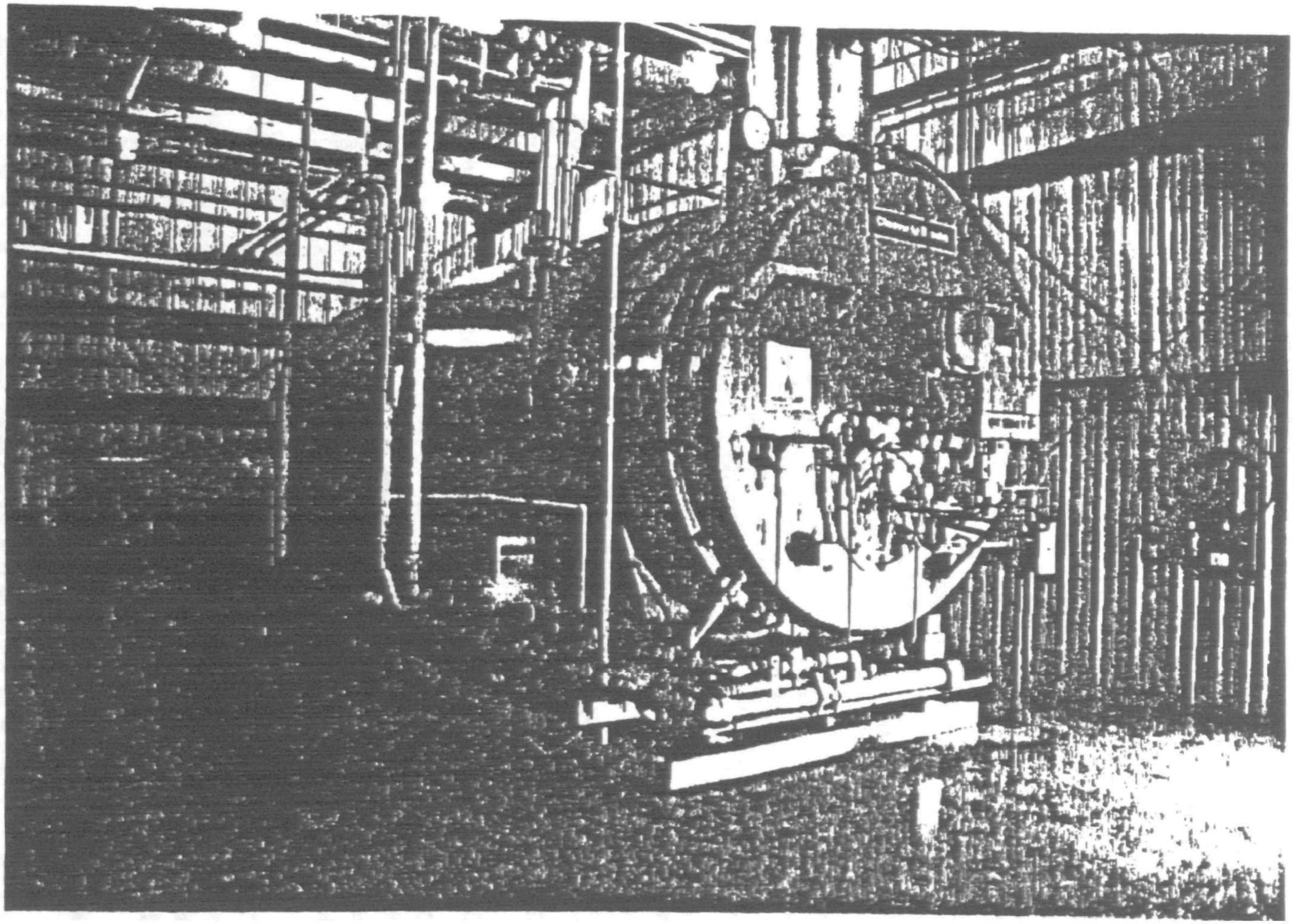

Figure 10 Cleaver-Brooks Boiler at Plant of Ajinomoto, USA. Landfill gas fueled boiler generates up to 24,000 pounds per hour of steam for plant process use.

TABLE 25. STEAM BOILER FUELED BY LANDFILL GAS: BASIC FEATURES

Location: Approximately 5 miles east of Raleigh, North Carolina

Nature of application: Landfill gas is extracted, piped 3/4 mile and used to fuel a boiler. The boiler supplies the steam needs of a pharmaceutical plant.

Project start date: December 1989

Participants: Natural Power, Inc. (Natural Power), Raleigh Landfill Gas Corporation (RLGC), Ajinomoto, Inc. (Ajinomoto), and City of Raleigh (City)

Component	Owned by	Operated by
Landfill	City	City
Landfill gas system	RLGC	Natural Power
Pipeline	Natural Power	Natural Power
Boiler (Cleaver-Brooks)	Natural Power	Ajinomoto/Natural Power
Boiler facility	Natural Power	Ajinomoto/Natural Power

Natural Power continued its efforts and the City Council ultimately awarded Natural Power the gas rights to Wilder's Grove landfill. It was known that the amount of waste in place was likely to produce sufficient gas. Gas availability was confirmed with a 12-well test program in 1987. Natural Power had meanwhile been examining energy options; the experience and interests of Bill Rowland of Natural Power, had included the use of two small (85 kW) landfill-gas-fueled Caterpillar engines at the Rowland landfill in Raleigh beginning in 1983. In the mid-1980s, Natural Power had begun to look at generating units based on Caterpillar, Cooper-Superior, and Waukesha IC engines and Solar Gas turbines, and investigated these more intensively with the acquisition of gas rights. Boilers were also investigated; they were determined to be among the most fundamentally attractive of the options based on return on investment, and specifically in light of revenue based on avoided costs of natural gas or oil, which landfill gas could displace.

In 1987, Ajinomoto, under a mile from the landfill, was found to be a potential customer for boiler steam fueled by landfill gas from Wilder's Grove. After further evaluation it was determined that the Ajinomoto boiler option was the best of the alternatives. Palmer Capital (through RLGC) established a development relationship with Natural Power and the arrangement that currently exists was implemented.

Natural Power notes that the present arrangement only came about after many years of work on the project during which there was no financial return. The project came to fruition only because of the continued interest, knowledge, and persistence of the participants.

5.5.3 Landfill and landfill gas system

Details of the landfill and landfill gas system are shown in table 26. Wilder's Grove is a large "cut and fill" landfill that has been in operation since 1972. The landfill receives 1,200 to 1,400 tons per day of waste, 5 days per week, and is expected to contain approximately 6 million tons of waste at closure. The landfill gas system was adapted by Natural Power from an initial design by SCS Engineers and, as of early 1991, had 70 wells. Other characteristics are as noted in the table.

By indicators including waste in place, the 1987 12-well test, and operational experience, the Wilder's Grove landfill generates methane at a rate probably greatly exceeding conversion needs. A good clay cover undoubtedly helps maximize methane recoverability and prevent air entrainment. Satisfactory gas

TABLE 26. LANDFILL AND GAS SYSTEM CHARACTERISTICS: WILDER'S GROVE

Landfill

Location: Raleigh, North Carolina

Type: Cut and Fill

Date Opened: 1972

Waste in Place (1991): 3.3 million tons

Waste Fill Rate: 325,000 tons/year

Total Fill Area: 125 acres

Area Now Filled: 65 acres

Climate: Temperate, warm, wet

Annual Rainfall: 50 inches

Daily, Intermediate, and Final Cover Soils: Clay

Gas Extraction System

Type: Vertical Well

Pipe Material: HDPE

Lateral/Main Header Piping: Below ground

System Details: Waste depth 40 to 100 feet. Well depth typically 80 percent of waste depth. Laterals and headers typically 3 feet below surface.

Current Landfill Gas Collection Rate: 900 cfm (1.3 million cfd)

Well Adjustment Protocol: GasTech® meters used to analyze for methane. Wells with flow below 50 percent throttled; flow of wells above 50 percent maintained and metered as needed.

Gas Composition: Near 51 percent methane

Gas Analysis Frequency: 12 times each month

quality of about 51 percent methane is obtained with a three-times per week monitoring and adjustment schedule. (Some problems have occurred with leaks and their detection in below-grade lines but these have not been serious enough to impede energy operations.)

5.5.4 Energy equipment: Blower station, pipeline and boiler

Equipment characteristics are summarized in table 27.

Blower/pumping station. Motive power for gas extraction and gas pumping through the pipeline is provided by a blower as shown in table 27, which receives gas at up to 40 inches of water vacuum and discharges it at approximately 12 psig. A filter system, with particle size cutoff of 1 micron, removes particles and aerosols from the gas. The pumping station with blower and filter was engineered by Perennial Energy, Inc., of West Plains, Missouri.

Pipeline. The pipeline extending from the pumping station at the Wilder's Grove Landfill to the boiler at the Ajinomoto factory is a 12-inch outer diameter HDPE pipe. The pipeline slopes from each end toward

TABLE 27. SUMMARY OF ENERGY EQUIPMENT CHARACTERISTICS

Blower station

- Blower: Hoffman 9 stage with GE motor
- Filter: Dual particulate (custom design, Perennial Energy)

Pipeline

12-inch outer diameter HDPE, length 3/4 mile

Energy Equipment

Boiler: Cleaver-Brooks CB 800 hp; normal rating 26,800 lb/hr steam on natural gas or oil

Building housing boiler: Standard rectangular, 25-foot by 52-foot; dimensions adequate to allow access, tube removal, and other maintenance work

the center so that all condensate can be collected at a single low point, located at a city sewer line near the midpoint of the pipe. The pipeline is sized for greater than the current gas flow to allow for possible increased landfill gas consumption by the end user (Ajinomoto, see later).

Boiler and building. The Cleaver-Brooks boiler is nominally rated at 26,800 pounds per hour of steam on natural gas. Landfill gas is fed to the boiler at 8 to 9 psi. Other characteristics of the boiler are listed in table 27 and presented in appendix J. This is a standard industrial boiler; its load varies as plant steam demand (for steam sterilization and other purposes) varies over the day. It is housed in a building specifically designed for it (as noted in the table), furnished by Natural Power.

One important boiler feature is its ability to operate on several different fuels: pipeline natural gas, number six fuel oil, and landfill gas. This provides insurance against steam supply interruptions because of a lack of landfill gas fuel. The principal modification to the boiler to adapt it to landfill gas use was (according to Ajinomoto factory staff) an increase in the number of gas injection ports (to accommodate the greater flow of landfill gas that must be introduced into the burner) and "minor" modifications to the air supply. Some fine-tuning was required after boiler installation.

5.5.5 Performance

Boiler. Over-all boiler availability and performance has been very good. The Cleaver-Brooks boiler normally supplies about 75 percent of the pharmaceutical plant's steam needs as the "primary" and lowest cost steam source; other backup boilers at Ajinomoto can fill in when it is not available. Natural Power reports that the boiler's availability to meet its share of plant steam needs when its steam production could be used has been near 97 percent since installation. Much of the initial down time has been shutdown for normal preventive maintenance and adjustments; a boiler gasket also had to be replaced. No operating problems that would be attributable to operation on landfill gas, such as unusual corrosion, have been observed.

The thermal efficiency of the boiler, as measured by Cleaver-Brooks at the Ajinomoto plant, has been 81.5 percent. This is close to the efficiency expected with pipeline gas and above the 80 percent efficiency Cleaver-Brooks guarantees with pipeline gas. At full output the steam generation rate has been near 24,000 pounds per hour, compared to an expected rate with pipeline gas of 27,600 lb/hr. This decrement in steam output of about 10 percent is expected as a normal consequence of the CO_2 dilution effects with landfill gas. The controls, which balance the air and gas feeds based on exhaust oxygen levels to tune the boiler, function well.

Other. The pipeline blower station, and blower and filter provided with it, have been performing well with no unexpected problems. Natural Power reports that no modifications have been necessary.

5.5.6 Emissions

Ajinomoto notes that the emissions have been standard for a boiler of this type, and satisfactory based on regulations.

5.5.7 Operation and maintenance

To date Ajinomoto reports that operating and maintenance needs for the boiler are "as normally experienced" for boilers of this size and type. The impact of minor maintenance work on boiler service was mentioned above. Automated controls allow the boiler to be operated with very little attention. The boiler incurs charges for electricity, inspections, fees, and insurance, which are discussed under "Economics" (section 5.5.8).

The filter in the automated condensate drain of the landfill gas pipeline requires cleaning, a minor job that is reported to take about 2 hours once a year. The filter in the pumping station has to be replaced when pressure drop increases significantly (from 2 inches w.g. to, say, 3 inches).

Note that much of the system has not operated long enough for indicative operation and maintenance histories to be developed.

TABLE 28. ECONOMIC DATA FOR LANDFILL-GAS-FUELED BOILER: RALEIGH, NORTH CAROLINA

Approximate system capital costs:

Item	Cost	Owner	Financed by
Landfill gas system	$500,000	RLGC	RLGC
Blower station	$100,000	RLGC	RLGC
Pipeline	$200,000	Natural Power	Natural Power/First Citizens Bank
Boiler and Building	$600,000	Natural Power	Natural Power/First Citizens Bank

Price paid for steam: Typically near $3.00/1,000 lbs.

Gross steam revenue, December 1989 (installation) to February 1991: $458,371

Current gross steam revenue, annualized: $450,000 to 500,000

Gross steam revenue distribution: Net proceeds to Natural Power, after royalties and gas purchase, are approximately 40 to 45 percent of gross revenue, approximately 40 percent of gross revenue goes to RLGC and approximately 15 percent to the City

Tax credits (to RLGC): Approximately $0.85/mmBtu sold in 1990 (this will fluctuate based on inflation factor)

Natural Power payments relating to boiler: Electricity, $12,500 per year; insurance, $26,400 per year; inspections/fees, $3,000 per year

Payments by RLGC to Natural Power for gas system operation and maintenance: Approximately $42,000 per year

5.5.8 Economics

Economic data are shown in table 28. The source of revenue is steam sales to Ajinomoto; the steam price is tied to the lowest cost fuel that is a reasonable alternative to landfill gas, usually natural gas from the local utility. This results in a steam revenue, as stated by Natural Power near $3 per 1000 lbs. Gross revenue figures from inception to February 1991 are as shown in table 28. Natural Power states that, based on current experience, annual revenue will continue to be $450,000 to $500,000. Gross steam revenue, paid to Natural Power, is used to pay royalties to the City of Raleigh and to purchase landfill gas from RLGC.

RLGC, owner of the landfill gas system and provider of the gas, also receives tax credits. The specifics were not available but are at a rate based on the Wilder's Grove gas recovery rate and should exceed $150,000 per year.

Other payment arrangements are as shown in the table, by Natural Power for boiler maintenance, and by RLGC to Natural Power for operation of the gas field.

Translating these figures into a return to the participants would need more detailed information in various areas such as financing arrangements and depreciation schedules and is not attempted here. All participants do appear to be satisfied with the economics.

5.5.9 Discussion

Performance effects attributable to landfill gas. The significant difference in energy equipment performance due to using landfill gas is the reduced boiler steam output, (approximately 10 percent). This is an expected consequence of the CO_2 dilution of the methane when landfill gas is used. In all other respects, performance appears to be comparable to that expected with more conventional fuels.

Other Issues. The performance of other equipment has been as expected, and the parties contacted (Natural Power and Ajinomoto) appear to be pleased. Economic performance has been satisfactory.

Lessons learned. The principal lesson learned to date appears to be that the system can function as planned and, more generally, that boiler fueling with landfill gas can be an attractive application.

Plans. In view of the availability of gas, additional pipeline capacity, and performance of the system to date, Ajinomoto and Natural Power are considering various additional gas uses including absorption chillers and steam turbines.

5.6 Electrical Power Generation Using Caterpillar Engines at the Central Landfill, Yolo County, California

5.6.1 Introduction and general overview

The Yolo County Central Landfill is about five miles northeast of the town of Davis, California. Gas from the landfill fuels an energy conversion system consisting of three Caterpillar engine powered gensets, whose collective output totals near 1,500 kW. The generated power is delivered via an interconnect 3/4 mile to nearby PG&E high voltage power lines. A photograph of the facility is shown in figure 11.

General site and equipment information is shown in table 29. The various participants and their responsibilities in the project are:

- Yolo Gas Recovery Corporation, a partnership between Palmer Capital and Hazox, has until recently owned and had overall managerial responsibilities for the energy equipment, that is, the gensets, gas cleanup train, interconnect and other associated equipment.

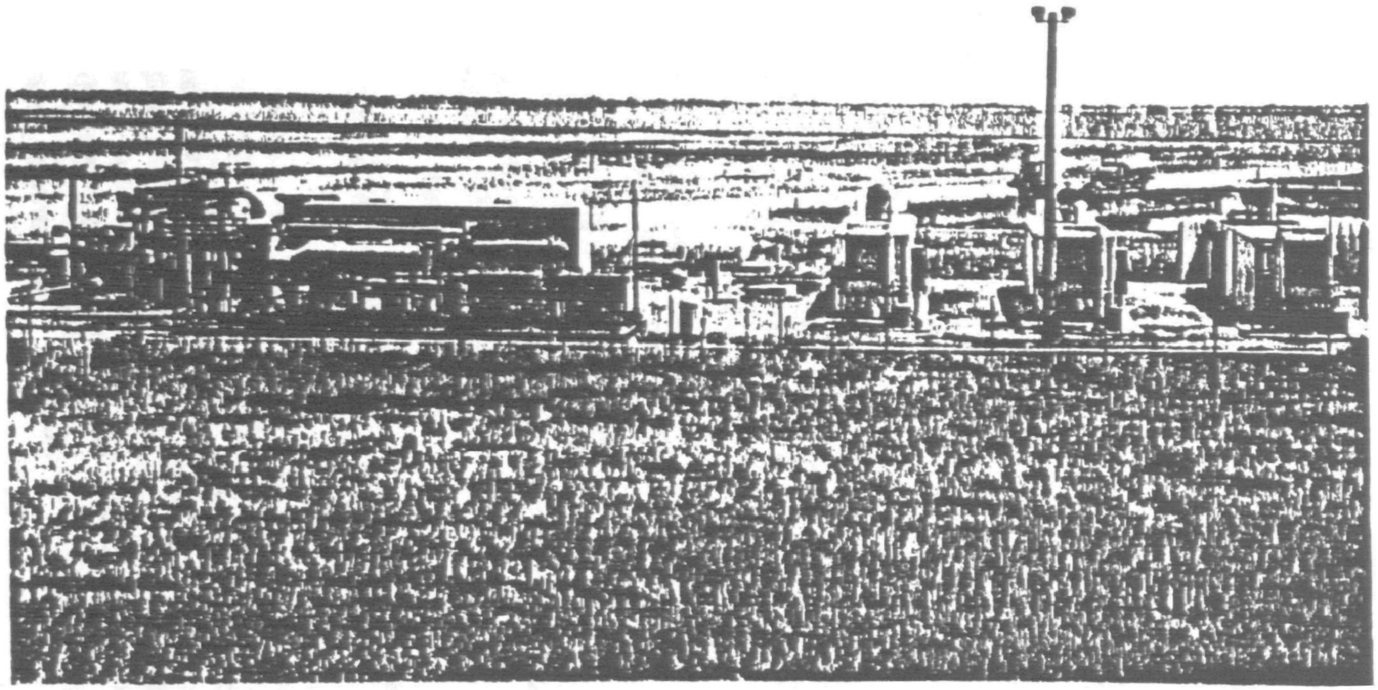

Figure 11 Electrical Generating Facility at Yolo County Central Landfill. Trailers each house engine-generators driven by Caterpillar G399 engines. Gas pretreatment equipment is to left of picture.

- Stowe Engineering has most recently been managing the day-to-day operation of the energy equipment.
- Operation, maintenance, and management of the landfill gas system and delivery of collected gas to the gensets has been the continuing responsibility of Monterey Landfill Gas Corporation, a subsidiary of EMCON Associates.
- Yolo County, the owner of the landfill, receives royalties based on net power revenue but has no managerial involvement.

YGRC has until recently received its benefits in the form of a portion of the gross electrical power revenue. Stowe and other equipment operators (see below) have received contract payments for operating the equipment, which are in part tied to performance. MLGC receives benefits in terms of tax credits, and a royalty on net electric sales.

This project has been marked by several difficulties, posed both by site conditions and equipment problems. Although some of the problems have been resolved, the problems and consequent falling revenue have been severe recently. These are discussed below. It must be recognized that records are in some cases incomplete because of recent changes and events that have occurred.

5.6.2 History of project implementation

The County initially commissioned a landfill gas recovery study in 1983, conducted by EMCON. Test well extractions were run in 1983 (and subsequently). The recoverable gas was also forecast at several times using various assumptions and an EMCON model. One set of the model projections for this landfill have been published (Augenstein and Pacey, 1991); the well tests indicated somewhat higher availability than did the model projections. Based on a combination of model and test well results, as well as assumptions about future waste placement rates, gas availability was judged sufficient to support the three gensets actually installed (if not immediately on installation, then within a reasonably short time thereafter as gas recovery would continue to rise over time).

In 1987, the county commissioned additional work with EMCON to develop a bid package to enable the selection of a developer for a gas recovery project. Several factors were helpful to implementation of this project: a favorable electrical energy pricing schedule, a significant and growing waste repository, and an enthusiastic and progressive County administration. This project was difficult to implement as the competition for the project involved a number of bidders and an extended bid process. Near the end of the bidding process, the local utility terminated the offering of its most favorable energy pricing contract (A California Standard Offer Number Four), which was one key to project viability. Palmer Capital had secured such a favorable standard offer contract from the utility just before the deadline, but no other bidder did so. Subsequent to Palmer's securing the standard offer, the County awarded Hazox the contract to develop the project. Hazox was unable to secure a contract as favorable as Palmer's from PG&E; however Hazox and Palmer recognized that each held a necessary ingredient for a successful project. They were able to jointly able to agree on a partnership approach which led to the formation of YGRC.

YGRC, which had responsibility for the energy equipment (excluding landfill gas recovery) invited EMCON to acquire the landfill gas rights and to undertake the collection system installation, operations and management. EMCON placed this project into its gas recovery subsidiary, MLGC.

Gensets driven by three Caterpillar G399 engines were secured by YGRC from Tenco Corporation, of Sacramento, California. This acquisition was possible at a favorable price, because this line of engines was being discontinued by Caterpillar and two of these engines were surplus to other needs that had been anticipated earlier; the third engine was reconditioned. This engine model has been used extensively as a naturally aspirated landfill gas engine (see GRCDA/SWANA, 1989). However, Yolo represented its first use in a lean-burn operating mode.

TABLE 29. BASIC FEATURES: ELECTRICITY GENERATION AT THE YOLO COUNTY CENTRAL LANDFILL

General Nature of Application: Electric power generation and sale to grid

Location: Five miles northeast of Davis, CA. (also, 12 miles northwest of Sacramento, CA)

Energy equipment: Gensets powered by three Caterpillar G399 Engines, with auxiliaries including gas processing skid and interconnect

Energy equipment owner: Yolo Gas Recovery Corporation (YGRC)

Gas extraction system design: EMCON Associates

Gas system operation: Monterey Landfill Gas Corporation (MLGC)

Landfill owner: Yolo County

Landfill operating contractor: Earthco

A compression/refrigeration approach to gas cleanup was selected, based on availability of a low-cost reconditioned unit that was obtained from Southern California where is had been previously used for landfill gas treatment. The possible significance of this choice to project problems is also discussed later.

Design and construction of the facility was carried out by Wellhead Electric Corporation of Sacramento, California. The first electricity production was in October 1989.

Of note as part of this implementation process is that a number of operators have been employed since startup. Wellhead Electric was the initial operator of the system from October 1989 to July 1990. EOS, Inc., was operator from July 1990 to February 1991. From February 1991 to May 1991, the system operation was supported by the efforts of Richard Ontiveros of Palmer Capital. From May 1991 to November 1991, Perennial Energy headquartered in West Plains, Missouri, was the operator; subsequent to withdrawal of YGRC and Perennial from the project (in November 1991) Stowe Engineering of Quincy, MA has been responsible for operations, as well as certain other managerial duties related to energy equipment.

5.6.3 Landfill and landfill gas extraction system

Details of the landfill and landfill gas extraction system are presented in table 30. The Central Landfill is a large landfill of the "area fill" type, begun in 1976. Fill rate is about 1,000 tons per day of mostly municipal waste; slightly over 3 million tons had been placed as of early 1991. Depth of fill ranges from 30 to 70 feet in the areas where gas is currently extracted.

The landfill is managed to maximize landfill gas recovery while maintaining a relatively high level of methane concentration (generally 49 to 51 percent). Modules are of variable size and depth; each module is monitored at least twice weekly and appropriate well and header adjustments in flow are made to achieve the desired control. There is relatively small fluctuation in gas quality and quantity on a short-term basis. Occasional problems occur in the gas collection system delivery, generally attributable to pipe joint failure, or flexible coupling failure. These conditions are usually repaired within a few hours of their occurrence. All piping is PVC and, with exception of the vertical wells, is above ground.

Landfill gas quantity should increase gradually as the waste resource expands over the coming decades.

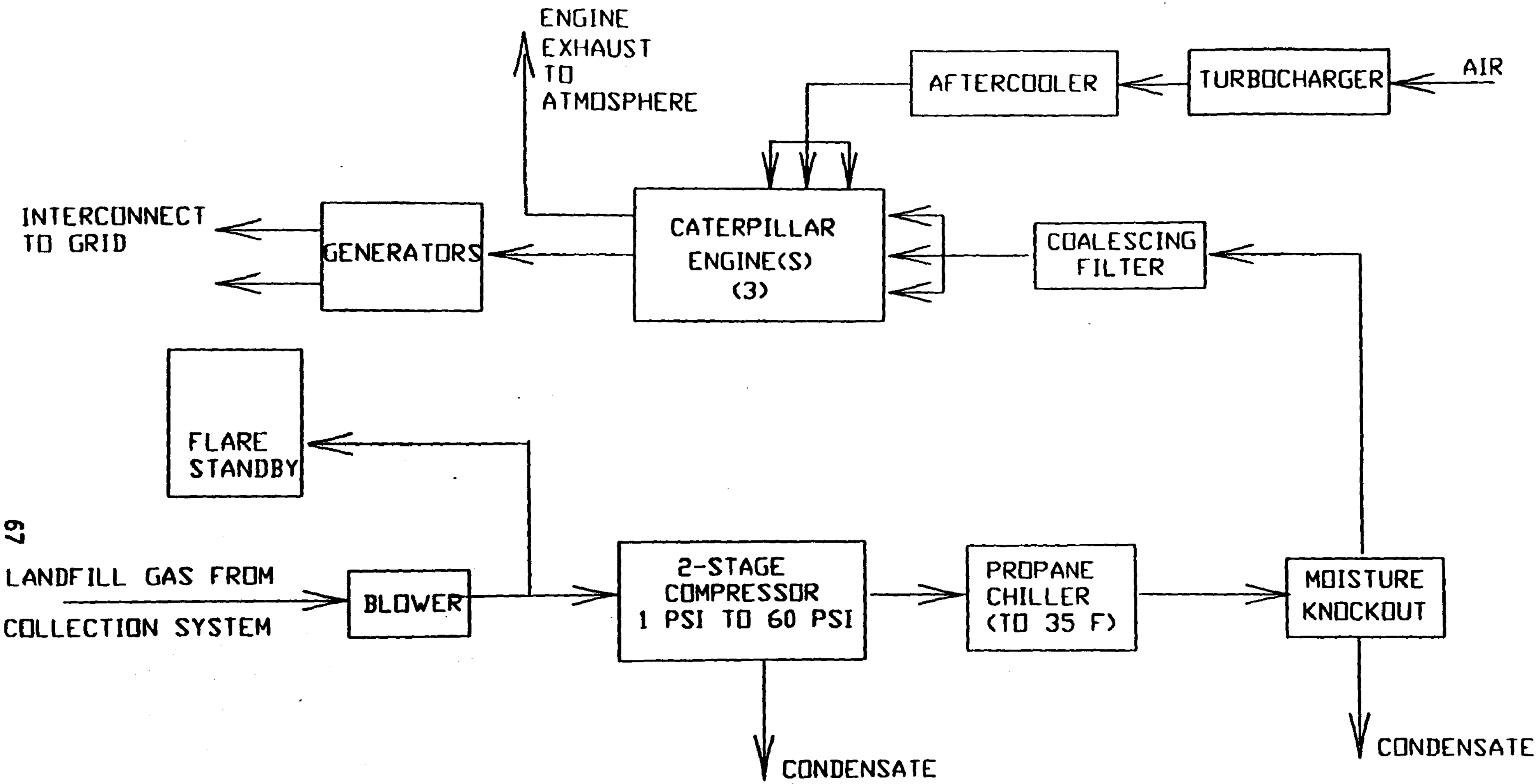

Figure 12
Electric Power Generation Based On Caterpillar Engines
At Yolo County Central Landfill
Simplified Block Diagram Showing Major Components

TABLE 30. LANDFILL AND LANDFILL GAS SYSTEM: YOLO COUNTY CENTRAL LANDFILL

Landfill

Landfill type: Area fill

Location: Yolo County, 5 miles northeast of Davis, CA (12 miles northwest of Sacramento, California)

Waste type: Residential municipal

Waste depth: To more than 70 feet

Fill rate: 280,000 tons/year (in 1991)

Climate: Semi-arid (rainfall: 15 inches per year)

Final cover: 4 feet of clay

Gas extraction System

Type: vertical well

Number of active vertical wells: 80

Laterals and main header: PVC, above ground

Permeable zone of wells: Extending from 20 feet below landfill cover to bottom of well.

Current collection rate: 900 to 950 cfm

Well adjustment objective: To maximize Btu delivery to gensets, while maintaining gas concentrations over 52 percent

Adjustment protocol: Flow of wells showing over 52 percent methane increased until concentration begins to fall; wells under 52 percent throttled. Wellhead composition monitored and well flows adjusted approximately once per month.

Gas analysis method: Wells and main header by GasTech® thermal conductivity based methane meters.

5.6.4 Gas preprocessing and energy conversion equipment

A simplified block diagram for the energy conversion system is shown in figure 12. A listing of the gas pre-processing and energy conversion equipment is presented in table 31.

Landfill gas handling and pre-processing. A variable-speed Hauck centrifugal blower normally provides the vacuum used to extract the gas from the landfill. The gas is delivered to a 2-stage compressor. The first stage compresses the gas to 15 psig, and the second stage further compresses the gas to a discharge pressure of 60 psig. (The blower may also be bypassed, and the field vacuum provided by the compressor.) Pre-treatment occurs initially by passage of the gas through 2 knockout pots before the gas enters the compressor. The gas entrains some oil and is heated to about 275°F in the compression cycle. The gas is then cooled to 78°F as it passes through oil knockout and an aftercooler. It then passes through a refrigeration unit to lower the temperature to 35°F; resulting condensate is bled at several takeoff points from the aftercooler and in refrigeration steps. The gas is reheated to 80 to 90°F as it leaves the refrigeration unit and passes through a coalescing filter just prior to being delivered into the internal combustion engines.

Electrical genset equipment. The internal combustion engines are Caterpillar units, Model Cat G-399, each rated nominally at 650 kW on pipeline natural gas. These are an earlier line of Caterpillar natural-gas-adapted engines. They are stated to be without certain landfill gas adaptations incorporated by Caterpillar[9] engines of more recent manufacture. Cooling water at the site has been provided by on-site wells; other options are under consideration because of water quality. An evaporative cooling tower is provided in association with each engine to cool air for carburetion.

The YGRC facility includes an interconnect that steps up voltage from that of the generator to power lines 3/4 mile away. The contract for power sale by the facility would permit the sale of up to 12 MW of power to the grid. Since the facility can typically generate near 1.5 MW, more than 10 MW of additional generating capacity could be accepted.

5.6.5 Performance and availability issues

Net engine output. The gross capacity of the gensets—if operated on natural gas—would be around 1,950 kW. The net power output has been experienced, however, at between 1,300 and 1,500 kW depending on operating factors. Factors leading to the lower power output include a normally expected decrement of about 200 kW due to the use of landfill gas, as opposed to pipeline or natural gas. An additional loss is due to about 200 kW of parasitics (including about 80 kW of power used by the refrigeration equipment on the skid). These two factors would alone reduce output from 1,950 to about 1,550 kW. Other problems including engine landfill gas compressor inefficiency (due to corrosion and suspected piston blowby), reduce output still further. An additional consideration is that less gas has been extractable in summer, when the landfill clay cover dries and is more permeable, than in winter. Gas does not limit output during the winter (the California rains seal the cover) but does slightly in summer; the result of all of these factors is that output is in the 1,300 to 1,500 kW range. (The expectations of YGRC were, apparently, that 1,700 kW of net output would instead be obtained at optimum operating conditions)

TABLE 31. GAS PRE-PROCESSING AND ENERGY CONVERSION EQUIPMENT AT THE YOLO COUNTY CENTRAL LANDFILL

Gas Handling and Processing

Blower: Hauck 25 HP. (at maximum power) model TBG-9-071-271-FX-1

Compressor: Joy Manufacturing, appx. 1 psig to 60 psig. (model WBF72XHD)

Chiller: York, propane working fluid, cools gas from ambient to 34-36°F (model not available)

Moisture knockouts and demisters: Custom fabricated

Final gas filtration, just prior to engine: Coalescing, model not available

Energy Equipment

Gensets: Three Caterpillar G-399 16 cylinder engines, driving generators. 650 kW (gross nameplate capacity on pipeline natural gas)

Cooler for engine intake air: Custom design, evaporative

On-site water supply: Wells

9 Personal communication, Curtis Chadwick, Caterpillar Corporation, Mossville, Illinois. September 1991.

Regarding efficiency, YGRC reports that the heat rate of the engine, when operating optimally, has been near 12,500 Btu/kWh (which is good). Note, however, that this value is somewhat uncertain given some gas flow measurement uncertainties.

As an introduction to further discussion of performance and availability issues, note that these have been poor because of both equipment and site-specific problems. These have included, but are not limited to, the following:

- Engines damaged by liquid landfill gas condensate entering the engine intake manifold with the landfill gas. (This is shown in site operating logs.) This has apparently occurred despite the existence of knockout pots and other equipment that were designed to prevent such occurrences.
- Corrosion of all engines, typical of engine attack by acidic combustion products as outlined in section 2. The most serious problem began with valve and valve guide erosion, which occurred to such an extent that valve play resulted in valves hitting and scoring cylinder liners, damaging them.
- Problems relating to well water hardness. As noted, the well water, which has been used for cooling is extremely hard (hardness reportedly increased sharply in 1989 after the major October earthquake, which may have cracked the well casing). This has led to deposit buildups in the engine block and oil cooler ports, through which the water circulates. Such ports had to be manually cleaned frequently, or else engines and oil overheated. Solids buildup and blowdown also posed a problem with evaporative coolers.
- Limitations posed by landfill gas supply. For reasons identified earlier, landfill gas supplies have been adequate during wet seasons when the moist clay final cover sealed well, but may have been slightly limiting (reducing power by up to 10 percent relative to that otherwise attainable) when the cover dried in the summer.

In addition to all of the above, less serious mishaps have occurred, such as Hauck blower breakdowns causing limited shutdowns, refrigeration equipment breakdowns, and electrical panel shutdowns because of overheating. There was also an extremely hard freeze in December 1990 that damaged water lines (by freezing and bursting), evaporative coolers, and other equipment.

Engine corrosion/wear problems might be considered among the most serious problems at the site. These are exemplified by recent experiences with the three genset engines, after an earlier overhaul that left cylinders in good condition. The findings were by borescope (a process allowing the interior of the cylinder to be inspected visually for damage). Engine 1 had run about 1,200 hours, engine 2 about 2,400 and engine 3 slightly over 3,000 hours. Borescope inspection showed that the cylinder liners of engines 2 and 3 were severely damaged. The damage apparently resulted from a sequence in which wearing valve guides allowed valve stems to wobble, the wobbling valves wore the seats, and this wear also allowed the valves to hit, score, and seriously damage the cylinder liners. The damage to engines 2 and 3 was serious enough that they were shut down. Engines 1 and 2 were renovated and put back into operations as of December 1991.

The problems above have resulted in service factors (output in relation to a selected standard of full continuous power production) which are low. Net kilowatt hour sales for 1989, 1990, and 1991 are shown in table 32. If service factor is defined as output in relation to continuous output at a power operation of 1,400 kW, the service factors for 1989 would be less than 50 percent, and for 1990 68 percent. YGRC's preliminary projection for 1991 (see further discussion below) was for power production which translates to a service factor of 47 percent.

5.6.6 Environmental/emissions

YGRC states only that the facility has been in compliance with all permit requirements, and that no problems have been experienced.

5.6.7 Operation and maintenance

The normal day-to-day operations at the site are carried out by a single operator. Additional maintenance is carried out such that YGRC has reported a total labor requirement at the site of about 60 hours/week.[10] Engine oil was initially Hydrotech, changed at approximately 1,000-hour intervals, but was recently switched to Mobil Pegasus 446. Intervals between changes are currently around 850 hours. YGRC, while not reporting exact intervals between engine rebuild, maintenance steps, and so on, reports (as could be expected) that these have been far more frequent than desirable[10]. The range of other operating difficulties described in 5.6.5 has been very much outside of routine; such information as was available on those problems was presented in that section.

5.6.8 Economics

Table 32 shows that economic information available when this report was prepared. A portion of the energy equipment capital investment was provided by a loan from the State Street Bank and Trust Corporation of Boston, Massachusetts. Gas rights were purchased by EMCON associates for $1.4 million dollars, and EMCON also furnished the gas system construction for an additional $300,000 as shown. The power purchase contract is a variation of California's Standard Offer Number 4. The contract allows PG&E to curtail (not pay) the vendor, YGRC, for up to 1000 hours per year. The gross revenues for 1989 and 1990, as well as YGRC's estimates for 1991 revenue are shown. It should be emphasized that 1991 revenues are only estimates; exact 1991 revenue and its allocation to participants is not currently available.

The economic situation has been quite evidently bleak. To summarize, the combination of lower than expected revenues, combined with high repair costs, caused default on the loan from State Street Bank in November 1991. Perennial Energy withdrew from the project in November. Stowe Engineering of Quincy, Massachusetts has taken over management of the energy equipment operations from YGRC and Perennial; MLGC (EMCON's) role remains unchanged and it is continuing to operate the gas system.

Despite these serious problems, these are positive factors from economic and other standpoints. The site has a good power contract, interconnect, and other features. With successful operation of the gensets at service factors comparable to Brown Station Road, Otay, or Marina as discussed in this report, Yolo is judged to have the potential for an acceptable return.

5.6.9 Discussion

The energy facility at the Yolo County Central Landfill has experienced problems that have been serious by normal standards of landfill gas energy projects, which often experience problems. The causes of the problems remain to some extent speculative, but it is worth offering speculation both as to cause and the potential remedies.

The corrosion problems seen with the gensets seem attributable to the combination of (1) reliance on a compression/refrigeration system for gas cleanup, with (2) engines whose conventional construction of earlier design may have imparted little resistance to acid gas corrosion. As noted in section 2, refrigeration will not be particularly effective in removing lower molecular weight halocarbons,

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[10] Personal communication, David Marquez, Palmer Capital Corporation, San Francisco, CA, September, 1991.

TABLE 32. ECONOMIC DATA: ENERGY FACILITY AT YOLO COUNTY CENTRAL LANDFILL

Capital investment for energy equipment: $1.8 million

Payment for gas rights, by EMCON: $1.4 million

Cost of gas extraction system (paid by EMCON): $300,000

Kilowatt sales and power revenue by year:

year	kWh output	PG&E power payments
1989	900,720	$70,844
1990	8,366,190	$877,518
1991 (est).	5,800,000	$700,000

Tax credits realized by EMCON: 1989 = $215,900, 1990 = $198,920

Power Contract: Variant of California Standard Offer 4.

Terms of Perennial Energy Contract: Payments based on kWh output--further detail not available

Distribution of power revenue to participants: Not currently available

Operating costs: Not currently available

particularly the CFCs. Halocarbons have evidently entered the engines and acid gas combustion products have been produced. Information is not available on how, specifically, the existing Caterpillar G399 engines that are not landfill-gas adapted differ from later models that are. It is, however, clear that corrosion susceptibility has been a major cause of problems at the site. (Also note that the G399 engine in stoichiometric-burn mode has served extensively in earlier landfill gas applications. See Chadwick, 1989).

The problem of condensate entering the engine appears, in retrospect, to be due to an unanticipated sequence of events that occur when one or more engines are idle. Line layout and design were such that with one or two engines operating, condensate would pool in the gas lines entering the idle engine(s) and on restart would be entrained into the engine being re-started in spite of traps.

Other problems at the site have already been discussed in some detail in 5.6.5.

Potential mitigating steps. It is not clear that the landfill gas refrigeration skid provides engine protection commensurate to its cost or energy consumption (80 kW). It is possible that effectiveness in removing the halocarbon components is minimal. Stowe Engineering, now in charge of the energy equipment (on behalf of State Street Bank) is considering eliminating it entirely. Stowe is also considering the replacement of certain key engine parts, currently corrosion susceptible, such as valve guides, with parts made of more corrosion resistant materials. This is in planning stages. Other problems have straightforward solutions: condensate entry into the engines can be eliminated through proper redesign. A soft water supply can be obtained by several possible routes now under consideration such as reverse osmosis. Gas supply problems to the extent seen could be readily eliminated by pipeline gas supplementation. Analysis and planning for a combination of such mitigating steps are underway.

5.7 Other Relevant Case Studies and Information

The preceding case studies presented recent information on six representative landfill gas energy applications in the U.S. Many additional descriptions and studies of past and current landfill gas energy applications, with varying amounts of detail, can also be found in the literature. Some further information sources are as follows.

Methane Recovery from Landfill Yearbook. The Government Advisory Associates, Inc. (GAA) has published (in 1986, 1988, and 1991) the *Methane Recovery from Landfill Yearbook.* GAA circulates a questionnaire to all U.S. landfills identifiable as delivering their gas to energy applications. The yearbook publishes data based on all responses obtained, which includes summary information on landfill features, gas recovery, type and capacity of energy application, owners/operators, contacts, and other information. Statistical analyses of collected data are also performed to develop overviews of issues such as economics (some of the statistics have been cited in this report). Although data in some areas are not as complete as the case study data in this report the yearbook contains a wealth of information and is by far the most complete available reference in terms of numbers of sites covered in the U.S.; it is available from GAA, 177 East 87th Street, New York, New York 10128.

SWANA/GRCDA *Landfill Gas Conference Proceedings.* Descriptions of landfill gas energy applications are found in past proceedings of landfill gas symposia sponsored by SWANA (Solid Waste Association of North America; formerly the GRCDA), as follows:

Tour Sites. In many instances the SWANA annual landfill gas conferences were held near the sites of landfill gas energy applications. These were generally available to be toured by conference attendees, and fact sheets including site description, application, and other data are published in the conference proceedings. A list of the descriptions of specific tour sites is presented, arranged by year and proceedings issue, in table 33. (Note that, as published in the conference proceedings, the data on many tour sites may be rather limited.)

Some of the more detailed case histories in past SWANA proceedings (in many cases listed under GRCDA), providing information somewhat similar to the case studies of this report, include the following:

- A discussion in the 1989 proceedings by major engine manufacturers (Caterpillar, Cooper Superior, Waukesha, Solar Gas Turbines) of experience on landfill gas (articles beginning on page 187). Discussions of corrosion effects are included.
- A discussion in the 1986 proceedings (page 158) on the selection of the energy conversion process and project implementation, for a landfill gas fueled boiler project for a Goodyear plant in Lansing, Michigan (Guter and Nuerenberg, 1986).
- A discussion in the 1986 proceedings of several electrical energy projects (Jansen, 1986, page 135, and Cortopassi, Toth, and Williams, 1986, page 185).
- A case study in the 1984 proceedings on the collection and use of landfill gas at a wastewater treatment plant (McDonald, 1984, page 109).
- A discussion in the 1984 proceedings on three small electric projects (Nielsen, 1984, page 135).
- A discussion in the 1984 proceedings on the planning of a medium Btu plant in Cinnaminson, New Jersey (Yeung, 1984, page 238).

SWANA, from whom past proceedings are available, is located at 8750 Georgia Avenue, Suite E-140, Silver Spring, Maryland, 20910.

U.K. Program. After the United States effort, the United Kingdom's (U.K.) effort is perhaps the largest. The documentation of energy uses in the U.K. has been extensive; a wealth of information has been compiled with active government support. Some brief fact sheets on two electrical generating projects and two boiler projects are included for reference in appendix K. . Lengthier case studies of interest include the following:

- A description of the electrical generating project at Stewartby, U. K., (ETSU, 1989) amplifying the summary description of this site in appendix K.

TABLE 33. SWANA LANDFILL GAS ENERGY FACILITY TOUR SITES

SWANA/GRCDA Proceedings Year	Tour site Described	Capacity and Application[1]
1991	Otay[2], San Diego, CA	1.7 MW, IC
"	Sycamore Canyon[2], San Diego, CA	1.3 MW, GT
1989	Crazy Horse, Salinas, CA	1.3 MW, IC
"	Santa Cruz, CA	0.9 MW, GT
"	Marina[2], CA	1.3 MW, IC
1986	Mountaingate, Los Angeles	4 mmcfd, SH
"	Olinda, Brea CA	5 MW, IC
"	Toyon, Los Angeles CA	9 MW, IC
"	Penrose, Sun Valley CA	8 MW, IC
"	Bradley, Sun Valley CA	3 mmcfd, PH
"	Industry Hills, Industry CA	SH
"	Puente Hills, Whittier CA	50 MW, ST + 3 MW, GT
1984	Cinnaminson, NJ[3]	PH
1983	Azusa, CA	PH
	Scholl Canyon, CA	IC
	Duarte, CA	2 MW, IC
	Sheldon-Arleta, CA[3]	
	North Valley, CA[3]	1.1 mmcfd
	Monterey Park, CA[3]	HBtu

1. Notation and abbreviations:

   MW = Megawatts electrical capacity
   IC = Reciprocating internal combustion engine application
   GT = Gas turbine application
   ST = Steam turbine/electric
   SH = Space heat application
   PH = Process heat application
   HBtu = High Btu for pipeline use
   mmcfd = Nominal extraction rate of landfill gas, million cubic feet per day

2. Also described in more detail in this report

3. Facility currently shut down

- A description of gas extraction from the Stone 1 Landfill and its uses. Uses include fueling a cement kiln, process heat for metals refining, process drying of chalk powder, and fueling cogeneration by an IC engine. Information is contained in Robinson, 1990.

Reports on these and many other British landfill gas projects are found in the U.K. Landfill Gas Energy User's Bibliography (British Library Document Supply Center).

5.8 Other Supplemental Literature

Three supplemental texts are included in appendices L, M and N. These became available too late to include them in preceding sections of the report.

The text "The Economics of Gas Recovery Systems in the United States" by George Jansen, is included as appendix L. (This work was presented in Melbourne, Australia on February 27, 1992.) It provides information and perspective on many issues covered earlier in this report from the viewpoint of a significant developer of landfill gas systems (Laidlaw Gas Systems). In particular, additional information is provided on internal combustion engine system economics, rate of return criteria, recovery project histories, and energy and economic trends. Appendix M presents the text of "Waste Management of North America, Inc. Landfill Gas Recovery Projects" by Michael Markham. This work was presented at the SWANA 15th Annual International Landfill Gas Symposium, March 24 to 26, 1992. It documents experience and operating philosophies of Waste Management of North America, Inc. (WMNA), the largest U.S. operator of landfill gas energy systems, at its 25 U.S. energy projects. Appendix N, "I-95 Landfill Gas to Electricity Project Utilizing Caterpillar 3516 Engines" describes a recently constructed facility using Caterpillar 3516 engines, which are engines adapted for low-pressure gas, and particularly landfill gas, use.

6. REVIEW, COMMENTARY, AND CONCLUSIONS

This report has presented case studies of projects where landfill gas has been used, generally successfully, in energy applications. It has also attempted to present an overview of the important issues regarding landfill gas energy uses, and (within existing constraints) a brief review of costs and other economic aspects. Some major conclusions can be offered based on this report's review and case study work. Technical areas can be identified where work on obstacles appears most likely to advance landfill gas energy use. The findings of this report also provide a context in which to review suggestions (by others) for facilitating landfill gas energy use by addressing nontechnical barriers.

6.1 Conclusions

Major conclusions from this report are as follows:

- Landfill gas can be a satisfactory fuel for a wide variety of applications, and its use in these applications provides environmental and conservation benefits. Many types of energy equipment that operate on more "conventional" fuels can also operate on landfill gas.
- Some reduction in the energy output of conventional equipment, of about 5 to 20 percent compared to its output on conventional fuels, is normally associated with landfill gas use.
- When landfill gas is used as a fuel, its properties, unique nature, and particularly its contaminants, must be considered. Many pitfalls are possible in landfill gas energy applications. Especially important are equipment damage from the gas contaminants, and gas supply problems such as shortages resulting from incorrectly estimating the availability of the gas.
- Cleanup stringency and methods vary widely. The necessary degree of landfill gas cleanup has not been well established. Cleanup by methods such as refrigeration can be expensive, both economically and in energy requirements.
- The optimum tradeoffs between cleanup stringency and the frequency of maintenance, such as oil changes, are not well established.
- Collection technologies are developed but probably could be further improved.
- Methods of forecasting gas availability for new sites are available but could be improved.
- Economics vary greatly; at some sites, economics may be excellent but at others, economics are a major limitation. Economics now tend to preclude smaller scale uses and remote site uses where electric power sale prices are low and there are no other convenient energy applications.
- Emission limits in some U.S. locations may also inhibit landfill gas energy uses despite an environmental balance sheet that would generally appear to be strongly positive.

The case studies of this report, comprising three reciprocating internal combustion engine sites, one gas turbine site, a site combining interval combustion engines and space heating, and one boiler site, have illustrated some of the possible applications of landfill gas. Recognize that these studies are only "snapshots," representing a small part of the total number of landfill gas energy projects and experience. Nonetheless the case studies illustrate some of the particular considerations regarding landfill gas, and support the conclusions presented above.

6.2 Further Needs

Based on the above case studies and cited literature, further needs for landfill gas energy use appear to include (as a partial list)

- Examining ways to improve and standardize gas cleanup for specific applications.
- Examining further the tradeoffs between approaches such as more stringent gas cleanup and maintenance measures such as more frequent oil changes.
- Examining further the optimum operating parameters, such as the best oil, coolant, and exhaust gas temperature for IC engines.
- Examining and documenting further the appropriate engine and other equipment design modifications to reduce current contaminant-related problems experienced with landfill gas use.
- Improving technology in ancillary areas that relate to energy uses, such as forecasting gas recoverability and improving gas collection efficiency and reliability.
- Developing and improving economic small-scale uses for the landfill gas.
- Developing further detailed documentation of experienced problems, and attempted and successful solutions to them, to benefit the community of present and future landfill gas users.
- Examining ways to reduce economic (and institutional) barriers to landfill gas energy applications. Further discussion of this issue is presented below.

6.3 Facilitating Landfill Gas Energy Use

Increasing collection and energy use of landfill gas would have consequences considered positive, as outlined in earlier sections (this is also reflected in the various regulations cited in this report regarding landfill gas). Technical obstacles remain, and technical improvements as outlined above should obviously help advance landfill gas uses. Nontechnical barriers appear, however, to be as important as the technical. As illustrated in section 4, high costs can combine with low energy sale prices at specific sites to make energy applications of much landfill gas that is generated uneconomical. Barriers can also be posed by other factors such as local emissions limits. Most gas generated by landfills is probably not yet being used for energy because of such reasons (although precise statistics are not available) with economics the dominant barrier. Incentives have therefore been recently recommended (as opposed to approaches such as mandated energy use). They were favored by expert groups such as the participants in the U.S. Environmental Protection Agency/Japan Environment Agency Workshop on Methane Emissions and Opportunities for Control (U.S. EPA/JEA, 1991) and an earlier workshop by the U.S. Environmental Protection Agency and the U.S. Department of Agriculture (U.S. EPA/USDA, 1989).

Some regulatory incentives now exist; federal facilitation is provided by tax credits under section 29 of the Code of Federal Regulations. The examples of policies in Michigan and Illinois that result in more favorable prices to landfill gas fueled electric generation are mentioned in appendix D. Some of the other suggestions worth noting that have been made for overcoming economic and other nontechnical barriers are as follows:

- Improving current federal tax credits and furthering state regulations benefitting landfill gas energy users (Workshop participant conclusions, U.S. EPA/JEA, 1991).
- Allowing greenhouse gas and NMOC emissions "offsets" for landfill gas energy use. (Conclusions of workshop participants, U.S. EPA/JEA, 1991).

- Using environmental "balance sheets" for landfill gas energy conversion that consider the total picture: not only the secondary emissions that tend to be the current focus of local and other regulations, but also the wider benefits to the environment by reducing radiatively forcing gas and other emissions and conserving other energy resources. Workshop conclusions in U.S. EPA/JEA (1991), state that "incentives should reflect the environmental benefits that will accrue from the implementation of the technologies and practices."
- Imposing a "methane tax" on decomposable waste that is landfilled, as suggested in Augenstein (1990). This would provide funding toward methane abatement, and could be preferentially collectible if the methane were abated through energy use. This option is akin to the "carbon tax" that is suggested on fossil fuels as a way of reducing their use and greenhouse CO_2 emissions.
- Supporting landfill gas energy uses with a levy on fossil fuel use (reflecting the emission consequences of fossil fuel use) similar to the British non-fossil-fuel-obligation (NFFO) (Richards and Aitchison, 1990)
- Creating goals for nonfossil energy production (Workshop Participant Conclusions, U.S. EPA/JEA, 1991).

Implementing any of these suggestions involves judgements on the valuation of various environmental benefits, relative to costs, and policy decisions, that must be made elsewhere. The pertinent factor to note is simply that these approaches would appear appropriate as means for facilitating landfill gas energy uses in the context of this report's findings.

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APPENDIX A
ESTIMATING GAS AVAILABILITY FOR ENERGY USES

Knowledge of the gas quantity likely to be available over time is critical for determining possible and appropriate energy uses and sizing equipment; this appendix presents a limited discussion of approaches to prediction. Note that the available gas is the generated gas, multiplied by the recovery efficiency (confusion often exists on this issue, or at least with the terminology).

Although existing knowledge is far from complete, for much of the waste in the U.S. the methane generation potential has been estimated as likely to be between 1 and 2 cubic feet per pound of total waste on a dry basis (in metric terms, 62 to 125 liters/kilogram, [l/Kg]) as stated in Augenstein and Pacey (1991). Similar estimates are given by Barlaz and Ham (1990) and Barlaz et al. (1990). Most of this gas will be generated over a period of 10 to 40 years after filling; this also corresponds to various rules of thumb that methane generation rates from wastes during the decade or so after placement may range from 0.04 to 0.2 cubic feet per pound of dry waste per year (EMCON, 1982; Van Heult, 1986). The recoverability of this generated methane for energy use is most likely to lie between 50 and 90 percent.

Generalizations such as above leave wide bounds on possible gas availability, and are of little value in sizing energy equipment, but the gas availability can be determined more precisely (and more usefully) by modeling, field pilot tests, or a combination of these. Without an in-place extraction system, or information from sources such as pilot tests, modeling techniques using waste placement and other appropriate data can still be used to develop *de novo* estimates of gas generation over time. The advantage of model projections is a cost typically less than 10 percent of field testing approaches. Work by various investigators has resulted in the development of several such models for predicting methane recoverability (EMCON, 1982; Van Heult, 1986; Zison, 1990; and Augenstein and Pacey, 1991). Gas generation does appear to be predictable, within limits, by the models but, unfortunately the error limits are large; generation predictions are consequently often expressed as a range (commonly upper and lower bounds are separated by a factor of two). The imprecisions that affect forecasts of gas availability come from several sources, including the difficulties in assessing the types and quantities of waste that were initially landfilled, temperature, moisture content, and many other critical variables (as listed in Augenstein and Pacey, 1991). Work to refine available models does not appear to have been extensive, although such work is now being undertaken as described in Thorneloe and Peer, 1991.

In addition to assessing the likely gas generation by modeling, pilot extraction tests may also be conducted over a limited portion of the landfill area (EMCON [1982], Biezer et al. [1985], and Woodfill and Barnum [1985]). Such tests are also inherently and sometimes seriously imprecise if extrapolations for the total landfill are made based on a few wells. Sources of error include, for example, inability to readily determine the volume from which a well, or groups of wells, is actually extracting, and the variabilities of gas generation over an inherently heterogeneous fill. Interpretations of models and small-scale field extraction tests require correction factors that tend to be site-specific and often have judgement components.

Once a gas extraction system has been installed (see next) and has been functioning long enough for a steady-state near-maximum recovery rate to be reached (depending on tuning and other factors, this is usually a few months), gas recoverability information will be reasonably precise and the available recovery results can be used to refine model predictions into the future. Models can be refined as discussed in Zison (1990) and Augenstein and Pacey (1991).

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APPENDIX B
GAS EXTRACTION SYSTEMS

Gas extraction systems are a complex topic; only a brief overview is given in this appendix. Much literature is available and ample detail can be found elsewhere (some starting points can be found in EMCON, 1982, and Poland, 1987).

The overall concern of the gas energy user is that the gas system will continue to deliver a reliable supply of gas, in the needed quantity, and that problems with the gas system will not reduce the output of, nor shut down the energy equipment. Collection efficiency is also a concern.

As an overview, gas extraction systems suitable for energy applications typically employ vertical wells or horizontal trenches to collect the gas from the mass of the landfilled waste. These are connected by laterals to a main header that ultimately carries the gas to the energy equipment. Vacuum is nearly always used to extract the gas. Several design considerations are important in assuring that the gas system functions correctly, including the most basic one of sizing pipes adequately for gas flow, and allowing for subsidence effects, draining condensate from lines to prevent its buildup, and allowance for accessibility to the system for leak detection and repairing breaks.

The overall extraction efficiency is typically affected by well spacing, and the permeability of the cover layer, typically the final cover. Collection efficiency is variously increased by reducing well spacing, and decreasing the permeability of the cover layers. It must be emphasized, however, that if the cover is at all permeable (and it almost always is), collection efficiency cannot, even in theory, be 100 percent with well systems as currently designed; economic limits on well spacing and other factors limit collection efficiency to levels that are more typically between 50 and 90 percent. Well spacing and depth are important issues; readers reviewing literature will note that the concept of "radius of influence" is often cited with respect to spacing wells. Within this radius, gas is assumed to be extracted by the well; outside this radius gas is assumed to be not extracted. However, problems with this concept have also been pointed out, in that the pressure influence of extraction changes gradually with the radius, and that the radius of influence is therefore difficult to define and apply (EMCON, 1982). (This comment is presented so that readers will be aware that differing opinions exist on both the radius of influence topic and others.)

Once the gas system is installed, it is adjusted ("tuned") to maximize recovery. Typical tuning involves gradually increasing extraction rates from wells over time, until falling wellhead methane levels indicate that air entrainment through the landfill surface, and into the collected gas, is significant. (Too much air entrainment limits gas extraction since it can alter methane generation rates unpredictably and undesirably, reduce gas usability for energy because of dilution, or even cause the landfill to ignite.) If methane production falls too far, the well must be throttled. The lag time between adjustment and attainment of the final equilibrium composition is significant, and overshoots and undershoots are common enough that tuning must often continue until several interstitial void volumes of gas are extracted, or for several months.

A more recent approach, which has only had limited application, uses the pressure drop across the cover as an indicator of extraction efficiency and to enable adjustments (Zison, 1990). This has the advantage in principle of enabling more accurate and rapid adjustments.

Oversizing the energy equipment because of too-optimistic gas availability estimates is one of the more common problems in landfill gas energy projects; gas estimates in such cases usually come from modeling or field pilot tests made without a full gas recovery system in place. When energy equipment is then installed (concurrently with the necessary gas system) the gas supply is found to be less than is needed. Installing the gas recovery system, determining availability as outlined above, and then installing the energy equipment would appear to be a preferred course to avoid such problems.

This has been very limited summary of gas extraction equipment, practice, and associated issues; the reader is referred to EMCON (1982), Poland (1987), and U.S. EPA (1991) for more detailed descriptions of extraction systems. The topic of collection systems and practice is important because difficulties with collection systems are also among the most common causes of problems with energy facilities.

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APPENDIX C
COMMENTS ON ENVIRONMENTAL AND CONSERVATION ASPECTS OF LANDFILL GAS ENERGY USE

Landfill gas energy use clearly has economic consequences, which in successful cases will include benefits to both energy producers and recipients of the energy. Using landfill gas for energy is also associated with significant environmental consequences, considered predominantly beneficial; these are best seen from the standpoint of the consequences if landfill gas emissions are not controlled.

If control is not attempted, the generation/emission of landfill gas poses some immediate hazards. Risks include fire and explosion from migrating gas, at the landfill itself, or in structures on adjacent properties, as well documented in Geyer, 1972 and U.S. EPA, 1991. The gas poses asphyxiation risks, since it may enter culverts, or other enclosed spaces. Concerns about these hazards were the impetus for many of the early gas control systems; many were simply barriers, such as trenches, to prevent gas migration, although some included extraction.

The next concerns that developed, first in areas of the country with air quality problems (such as the Los Angeles Basin), were those regarding emissions of the nonmethane organic compounds (NMOCs), reactive organic gases (ROGs), or ozone precursors contained in the landfill gas. Various estimates of the magnitude of these emissions have been presented, but at whatever magnitude may be correct, they are significant (U.S. EPA, 1991). Concern over these has risen steadily to the present and further discussion of air quality impacts and regulations is presented elsewhere in this report.

The final concern regarding landfill gas, from a global standpoint and over larger time periods, is its potential contribution to changes in the earth's climate (Thorneloe and Peer, 1990; Augenstein, 1990). Interest in this issue has increased sharply over the last few years. This interest relates to the continuing atmospheric buildup of "greenhouse" gases, of which one of the most important is methane. Whatever the details, it is expected that if current trends continue some climate change should occur (although timing and magnitude are uncertain) and some consequences could ultimately be serious (Houghton and Woodwell, 1989).

Landfill methane's significance to climate change arises because the radiative forcing ("heat blanketing") effect of methane, as a greenhouse gas, is about 25 times that of an equal volume of CO_2. Enough waste is landfilled annually in the U.S. that conversion of even a modest fraction of the landfilled organic material to methane in landfill gas, which is then evolved to the atmosphere, contributes significantly to the ongoing increase of global "heat blanketing" or radiative forcing that is due to greenhouse gas buildup. Estimated landfill methane emissions in references that include U.S. EPA (1991) and Augenstein (1990) typically range from 3 to 20 teragrams per year (Tg/year) for U.S. landfill methane emissions to the atmosphere. Based on atmospheric modeling, even a lower estimated range of emissions of U.S. landfill methane of 3 to 8 Tg/year could be making a difference of 1 to 2 percent in the earth's annual increase in total greenhouse gas radiative forcing (Augenstein, 1990).

The collection and destruction of landfill methane, whether through energy use or other routes, ameliorates hazards and nuisances mentioned earlier and obviously prevents its emission into the atmosphere; it results in a reduction in NMOC emissions, and any global warming consequence that would otherwise occur from that methane. Emitted methane's greenhouse potency—compared to the CO_2 that would result from burning that same methane—depends on atmospheric residence time, and other factors. Considered from the standpoint of time intervals of up to 40 years, the combustion of methane to CO_2 has been calculated to reduce the greenhouse impact (radiative forcing) that would otherwise occur from it by over 90 percent (Augenstein, 1990). In that work the economics of landfill methane abatement (without necessarily using the gas for energy) were found quite attractive (1 to 10 percent as expensive per unit radiative forcing benefit) compared to other approaches—photovoltaic or nuclear for coal—whose costs could be identified (Augenstein, 1990). Similar conclusions, that landfill methane abatement is one of the lower cost United States approaches to address potential climate change problems, have been reached by a recent study by the National Academy of Sciences (1991).

While landfill methane extraction and abatement appears attractive as an approach to global warming to the extent that it can be practiced—an economic "fix" to the landfill methane component of the problem—using methane for energy has additional benefits. The energy use itself will typically offset fossil fuel use elsewhere, reducing net CO_2 emissions to the atmosphere (fossil fuels, usually oil, are the "swing" fuels whose use is most typically displaced). When energy and other methane recovery-related revenue depend on efficient collection of the gas that is generated, it is also reasonable to assume that recipients of the resulting revenue will make efforts to maximize collection efficiency. The economic incentives likely facilitate the attainment of environmental benefits (as reduced methane emissions).

Using landfill gas for energy also uses an asset that would otherwise be wasted, and the beneficial energy use therefore represents conservation. Although estimates of landfill gas energy potential cited in section 1 were "only" about 0.2 to 1 percent of the energy total used in the U.S., this quantity of energy is still highly significant by most standards—equivalent to the total energy requirement of half a million to possibly well over a million U.S. citizens.

Although the results of using landfill gas for energy can be considered primarily beneficial, some negative consequences can be of concern. These are principally the emissions from the energy uses; the most significant negative impacts (affected by regulations) are oxides of nitrogen (NOx) and carbon monoxide (CO); NOx is the most important and can be a limiting factor. On balance, however, the benefits of landfill gas energy use do appear to outweigh the negatives. Emissions and other regulatory issues are addressed in elsewhere in this report.

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APPENDIX D
REGULATORY ISSUES WITH LANDFILL GAS USE

Regulations are another area of complexity, for which this appendix presents a brief overview with historical notes. Regulations in several areas significantly affect landfill gas energy use. Some of these regulations concern hazard and nuisance abatement, and air pollutant emissions reduction. Another pertinent set of regulations are statutes, both state and federal, providing incentives to facilitate energy applications and outlets for the produced energy.

In the history of landfill gas control regulations, regulations initially addressed the landfill-gas-related dangers and nuisances (discussed in appendix C). These were followed by regulation, primarily local, that addressed ROGs. (Earliest federal regulations did not normally directly affect landfills, except, for example, as they favored landfilling over previous disposal methods for health and safety).

Some of the most pertinent current legislation on the national level is that of recently enacted amendments to the federal Clean Air Act. Details of the proposed regulations, which as applied to landfills are being finalized, are documented (Federal Register, May 30, 1991). The primary purpose of this legislation is to reduce emissions of NMOCs (ozone precursors), although other important objectives exist (U.S. EPA, 1991). It is expected as a consequence of the proposed regulations that most of those landfills capable of supporting energy systems, but that are now without any controls, will be required to install gas recovery systems.

The proposed regulations prescribe the methods for determining whether landfill gas recovery is required at specific sites, and the degree of NMOC abatement to be obtained with the recovered landfill gas. In very brief overview, landfills established to emit 150 Mg or more a year of NMOC's are required to install controls. Energy conversion equipment such as gas turbines, IC engines, and boilers may serve for control if equipment accomplishes 98 percent destruction of NMOC's or has 20 ppm or less of NMOC's at the outlet. Performance testing is required to verify the degree of control. These are but summaries of some key points; readers should consult U.S. EPA (1991) for full detail.

Many other state and local regulations exist regarding other landfill-gas-related issues, including condensate disposal, effectiveness of gas migration control, and so on (Maxwell, 1989; Petersen, 1991). Discussion cannot be presented here; the reader should simply be aware that such regulations exist and are very likely to have significant impact on energy applications.

Some local emission regulations and regulatory guidelines are tending toward greater stringency than federal standards, as exemplified by California's recent proposed guidelines (California Air Resources Board, 1991). California's draft guidelines propose that energy conversion approaches must meet that state's definition of best available control technology (BACT). Further discussion is omitted here except to note that such stringency may limit equipment and approaches (and could tend to reduce the amount of landfill gas energy use).

The benefits of landfill gas energy use (see appendix C), in combination with a general congressional and state intent to facilitate small-scale energy use, have resulted in legislation that helps facilitate market acceptance for electricity produced from landfill gas (and similar sources) as well as legislation providing credits and various incentives.

The provisions of the Public Utility Regulatory Policies Act (PURPA) are very important to those producing electricity from landfill gas. PURPA allows producers of landfill-gas-fueled electricity in the U.S. to sell to utilities at the utility's "avoided" cost, that is the sum of costs the utility would otherwise experience in terms of fuel, new plant construction, and other categories to produce the power. Provisions of federal law are somewhat general with numerous accounting and costing methods possible; states such as California have somewhat standardized the purchase agreements with "standard offers" (Hale, 1989) that simplify the negotiation process.

The congressional wish to encourage alternative energy has also resulted in federal tax credit legislation (Hatch 1991). This legislation provides a variable U.S. income tax abatement, or offset, credit with a current (in 1991) value near 0.85/MMBtu for gas collected and sold for energy applications. The energy application must be profitable for the credits to be realized, and there are other constraints.

Some state legislation to facilitate landfill gas energy use also exists. Michigan law, for example, specifies an avoided cost formula for sale of electric power by a landfill gas facility to a public utility that gives a favorably high price; Illinois specifies that a utility must buy electricity generated from landfill gas in a county at the same average rate at which it sells it to customers in the county (Greenberg, 1990).

Regarding the impact on landfill gas energy use, the control regulations, and in particular the Clean Air Act regulations, will probably result in the installation of gas recovery systems at many landfills that could support energy systems. The gas system required for energy could thus be regarded as a "given" and in the energy economics would not necessarily need to be accounted for as an expense against energy production. The emission limits under the federal Clean Air Act were based on a review of currently attainable equipment performance.

Regarding legislation that facilitates landfill gas energy use, the energy use tax credits provide a benefit that can favor various energy applications, for example by offsetting gas collection expenses. State provisions are also obviously beneficial where they exist. PURPA provisions facilitate sale acceptance by grids of the output of electrical cogenerators (note, however, that the sale price now available for landfill-gas-cogenerated electricity has tended to fall for reasons including falling avoided fuel costs, utility generating overcapacity, and a hotly competitive auction market in which other cogeneration sources bid to sell power to utility grids).

The restrictions on energy equipment emissions, on the other hand, as applied or developing in many areas in the U.S., imply significant additional expenses on landfill gas energy uses. These emission restrictions characteristically treat the landfill gas emissions as a *de novo* source. This does not consider, as part of an overall assessment, the environmental benefits such as more efficient NMOC emission control and other consequences that occur due to energy applications. In particular, the energy conservation, and also the offset effect of landfill gas energy use in reducing net emission of radiatively forcing gases, is typically not now considered by state or local regulators.

REFERENCES TO APPENDIX D

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Federal Register, Vol. 56, No. 104, Thursday, May 30, 1991. Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills. Part III, p. 24468.

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APPENDIX E
GAS COMPOSITION ANALYSIS

In contrast to the case with more "conventional" energy sources, landfill gas users may need to check the composition of their fuel more or less regularly. Methane and energy content can change as the consequence of extraction procedure, or other factors. Oxygen in the gas can indicate leaks that need repair. Gas system "tuning" is often needed to provide a gas stream of appropriate quality to keep energy equipment running, and this tuning can require frequent well-by-well analysis. In addition the gas will contain a range of contaminants, whose level varies with landfill, and over time. As composition can have important energy consequences, gas composition analysis is reviewed briefly here.

Methane and oxygen content can be determined by various techniques of which the most common is a portable meter combining thermal-conductivity-based methane analysis with electrochemical-cell oxygen analysis (manufacturers include GasTech and MSA). This equipment has the advantage of speed and portability. Greater precision is available through gas chromatography techniques. This equipment is less portable and less frequently used, most often to sample the total gas stream supplied to the energy application. A discussion of methodologies for methane and oxygen content analysis is presented in Van Heuit, 1983. One "bottom-line" indication of gas quality is of heat of combustion, which may be checked by on-line calorimetry.

Compositional analyses for gas trace components (all components other than methane, carbon dioxide, nitrogen and oxygen) down to extremely low levels can be accomplished by a variety of methods including gas chromatography/mass spectroscopy (for example as described in Gas Research Institute, 1982). Chlorinated hydrocarbons are usually the greatest concern because of equipment corrosion potential (discussed elsewhere in this report); techniques for analyzing for these with portable equipment are described in Zimmerman et al. (1985) and independent outside laboratories recommended by engine manufacturers for chlorine content analyses are given in Chadwick (1989).

This is largely presented to provide awareness that analysis may be required to assure performance. Interested readers should seek further information from literature, equipment manufacturers and/or contact others with expertise on this issue.

REFERENCES TO APPENDIX E

Chadwick, C.E. 1989. Application of Caterpillar Spark-Ignited Engines for Landfill Gas. Proceedings from the GRCDA 12th Annual International Landfill Gas Symposium. GRCDA/SWANA, Silver Spring, Maryland.

Gas Research Institute (GRI): Landfill Methane Recovery. Part II: Gas Characterization. Final Report (1982). Gas Research Institute, Chicago.

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APPENDIX F
COST, REVENUE, AND OTHER ECONOMIC COMPONENTS: DISCUSSION

Readers must recognize how site-and-situation specific landfill gas energy economics can be; the site-to-site variation in capital and operating cost were reviewed in the main text. Development or presentation of detailed process economics are beyond this report's scope. It is possible, and can be helpful, however, to review some more commonly encountered components of energy systems (whether electrical or other) with some discussion, where possible, of cost basis and reasons for variation over typically experienced ranges. The discussion to follow addresses, in turn, capital and related costs, operating and maintenance costs, and revenues and other benefits.

Capital cost items

"Capital cost" for equipment can have various definitions. It is convenient here to use the installed cost, defined as including the total burden of engineering, installation, and permitting as well as other cost (as well as these can be estimated and allocated) to arrive at the total cost for a functional plant equipment component. Capital cost will be expressed either for the total for a site, or in terms of the normal capacity units of the equipment, such as cost per kW or Btu/hr. (For interested readers wishing to translate cost components from one basis to another, note that 1 cfm of landfill gas corresponds to about 2 to 3 kilowatts, 20 to 25 pounds per hour of steam, or about 500,000 to 650,000 Btu per day of space heat.)

Capital costs for frequently encountered items or categories using the definition above are as follows:

Gas system. Gas system costs will be likely to lie between $200 and $2,000 per standard cubic foot per minute (scfm) of landfill gas, based on recent SWANA and U.S. EPA cost data (SWANA, 1991; U.S. EPA, 1991). ($1.00/scfm landfill gas will correspond to about $0.40 to 0.50 per kW of electrical capacity or $0.035 to $0.05 per pound per hour of steam, or $1.30 to $1.50 per million Btus per day of process heat when energy equipment is continuously on-line. Thus for the cited figures it may be worked out that the gas system costs may lie roughly at $80 to $1000/kW electric capacity, $7,000 to $100,000 per pound per hour of process steam, or $250 to $3,000 per million Btu per hour of peak space heating capacity.) The costs tend to rise relatively slowly with size, that is, gas systems become more economic per unit throughput as scale increases.

This cost might or might not be allocated to the energy application, depending on whether the system would be required in any event without the energy system (see discussion in appendix D for Clean Air Act implications).

Gas cleanup. Landfill gas cleanup system costs can be extremely variable and, based on experienced costs, would appear to range from as low as $5 to well over $100 per cubic foot of landfill gas flow per minute (corresponding roughly to $10 to $500/kW for electrical applications). Part of the reason for this variability is that needs vary by site. Also, in the absence of knowledge about what type or degree of cleanup is most cost-effective, a wide range of equipment is applied.

Condensate removal and treatment. The costs for this, on an incremental basis, can be small if the condensate can be returned to the landfill or combined with leachate flow, to which it adds a minor volumetric increment. However handling costs may be higher in many areas where separate condensate handling and treatment is required. No figures are immediately available but discussions of the issue are presented in Maxwell (1989) and it is well for potential energy users to recognize this as a potential expense; it is a cost component incurred if gas recovery is mandated, whether or not energy recovery is practiced. Like the cost of the gas system itself, is a cost that might be a "given" and not necessarily expensed against conversion.

Energy equipment

Electric generation-reciprocating internal combustion (IC) engines. Electrical generation using these engines has been to date the application for the majority of U.S. sites. Costs for complete, new reciprocating IC engine-generator sets would appear to lie in the range of $1000-2500/kW. This includes the basic genset package (engine, turbocharger if used, and control systems) but excludes costs such as those for interconnects presented elsewhere in this capital cost summary. Costs per kW fall with size, or can be reduced if equipment is acquired used, as it has been for many sites.

Electrical generation using gas turbines. For combustion gas turbine-generator sets costs would appear to lie between $2,000 and $3,000 per kilowatt.

Fuel cells "future technologies." As a potential electrical generation technology, fuel cells come off well in terms of capital costs, with cost estimated to be under $2000/kW. However attainment of this will require further manufacturing cost reduction from current levels, and validation of operation characteristics on landfill gas, which is planned (Sandelli, 1992).

Interconnects with electrical utility grids (specific to electrical generation). These are another item whose costs can vary widely; the range of variation within this report's case studies is from about $20/kW (reported for Marina) to $500/kW (reported for Prince George's County). The reasons for variation include whether the interconnect is one or two-way, the voltage step-up needed for power sale, the scale, and of particular importance as many landfill sites are remote, the distance power lines must be run from the generation site.

Boilers. Capital cost of boilers, where they are used, will vary with size, steam pressure and other factors. Full cost data for boilers are not available, and landfill gas boiler applications are few, but for one example (a case study described in this report), capital costs are about $25,000 per 1,000 pounds of steam per hour, including all ancillary control equipment. This is but a single case, and it is likely that boiler costs per unit capacity will vary substantially with circumstances. Qualifiers to cost issues are that the case study cost included a building (not always a needed component) and that pipelining costs will be extra (they are an additional $6,000 per 1,000 pounds of steam per hour for the case study site, on top of the cited $25,000 per 1,000 pounds of steam per hour). Pipelining costs will probably be significant because appropriate users of steam, if available, will often be some distance from the landfill.

As an overview, the capital cost of a boiler will be 10 to 20 percent of an engine-generator set that uses landfill gas at the same rate, and with appropriate situations very attractive returns are possible on their relatively low capital investment. Specific capital cost information on boilers will be available from vendors.

Capital costs of other energy technologies. Numerous other applications are possible for landfill gas (for example process and space heating, vehicle fueling, and other applications as mentioned above) but capital costs are so situation-specific that cost estimates will not be attempted here. The capital costs for many of these technologies fueled by conventional fuels are available from manufacturers and other sources. The recommended approach would be to obtain these costs on more conventional fuel sources and then add to them the additional costs estimated as specific to landfill gas fueling.

Other capital cost categories. There are, in addition to cost items above, other situation specific and quite frequently major capital costs. These can include rights to the landfill gas, or rights to favorable power contracts. Other cost categories include pipeline costs and the costs for providing on-site utilities such as water at remote sites. Power contracts and landfill gas rights can be evaluated in a present worth type of evaluation, in terms of the extra return component over time expected from gas production or contract. Other comment will be omitted on these costs because of their variability except to note that such cost components may exist and comprise large fractions of total capital cost.

Capital-related fixed costs

The capital-related fixed costs are charges related to the investment which can include interest on debt, taxes, insurance, depreciation, and the like. They are the part of the energy cost that results directly from the capital investment, and are proportional to the capital investment (which is why lower capital investment is desirable). As capital costs are highly variable, fixed costs are likewise variable; in fact on a percentage or ratio basis the fixed costs will be even more variable than capital costs (the greater variability relating to interest rate variation and other factors).

(Note that fixed costs continue whether the facility is producing energy or not. Problems such as energy equipment or gas system breakdown or other factors that result in lowered energy revenue can result in failure to cover fixed costs, and serious financial problems. These can include, if not loss of investment, loan defaults or worse.)

Operating costs

Only brief comment on operating costs will be given here. Detailed, publicly available data are limited (and the case studies of this report may add somewhat to the existing body of publicly available information).

Operating and maintenance costs can either be viewed against a baseline of operation of a similar energy application on more conventional fuels, or as the cost of operation reported by the equipment operators in terms of units of output. In contrast to capital costs, which can be broken out to a fair level of detail, lumped operating costs are frequently reported for all of the equipment in the aggregate in an energy application. They tend to be closely proportional to the energy production.

Gas system. Some of the factors in operation of gas systems are discussed in Augenstein and Pacey (1991). Variables include landfill size, porosity of cover, frequency of tuning required, and objectives (i.e. pipeline or low Btu gas extraction). Operation and maintenance costs will range from a low value of around $30,000 per year to well over $200,000 per year.

Engine operation costs. The cost of operation and maintenance of reciprocating IC engines on landfill gas, compared to operation on more conventional fuels, is of interest because of the extent to which such engines are used.

One industry observer has commented[1] that the operating and maintenance costs of landfill gas fueled engines increase very roughly by 25 percent compared to more conventional fuels. Clearly, the extra cost will vary from engine to engine and site to site, (as it obviously does for engines operated by that organization as documented in Vaglia, 1989). In addition relative cost will differ with cleanup effectiveness. Nonetheless this number is one useful guideline estimated by an organization with extensive experience in such operation.

The operation and maintenance costs of engines have also been reported as cents per kWh of electrical output. One reference (Jansen, 1986) presents an averaged cost of 1.83 cents per kilowatt hour for generation scales of 500 to 1000 kW based on Gas Recovery Systems' (now part of Laidlaw Gas Systems) experience, of which 0.0035/kWh is labor and the rest cost of an on-site operator. This cost, updated to the present, would imply a cost of about $0.02/kWh. One engine manufacturer has recently detailed estimated life-cycle maintenance costs for an engine (its G7042GSI) on natural gas in deriving 1.1 megawatts of generation under "severe" operating conditions, defined as operating at maximum continuous recommended load[2]. These costs, amounting to $0.0045 per kWh, do not include on-site operator labor, or costs for maintenance of other aspects such as gas cleanup, that would be required at a landfill gas facility. Operator labor at an assumed burdened cost of $50/hr full time and an engine service factor of 80% would add $0.013/kWh to give a total of $0.0175/kWh. The gross totals of the

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1 Personal communication, Stan Zison, Pacific Energy, to Susan Thorneloe and Don Augenstein, March 1991.

2 Personal communication, Jeff Balis, Waukesha, June 1991.

Waukesha estimate and Jansen (1986) both imply current costs near 2 cents per kilowatt hour, which would seem a representative benchmark for a scale near one megawatt. However variability in such estimates is illustrated in that, between the estimates, both the labor and equipment maintenance components vary threefold and are reversed.

Even for smaller electrical operations, it has been found to date that full-time on-site operators are still required. Labor costs for such smaller scale operation are such that few electrical projects at 500 kW or less can presently be viable.

Interconnect. Often associated with electric power generation is the cost for an interconnect. If the interconnect is utility financed, charges are levied for both operation and maintenance, and the utility's fixed charges and return may be a total of about 2 percent of the capital cost per month.

Operation and maintenance costs for other equipment. There have been relatively few reported data for landfill gas fueling of boilers, kilns, process heat applications and the like. In several cases for which information is available (which include a boiler and space heating application presented in this report) no operation and maintenance differences or cost associated with them could be identified. Operation and maintenance costs for such specialty applications should in any case be derivable from the equipment on conventional fuel with add-ons if established as necessary for operation on landfill gas.

In general, operation and maintenance costs are specific to scale, equipment, and site, and factors such as gas contamination. They are dependent on the diligence with which maintenance is performed. Compared to a basis of trouble-free operation on "clean" or pipeline gas, these costs will obviously escalate sharply on a unit energy output basis when operating problems as described earlier are encountered, which both increase costs and reduce output.

Royalties. Royalties are typically a variable cost levied as a fraction of the total gross energy revenue, they are often zero and otherwise most typically in the range of 5 to 20 percent.

In theory, for a viable project, the sum of costs above should be below revenue, discussed next.

Revenue Components

Benefits that a project accrues can include cash sales of energy, costs avoided through displacement of energy purchases, as well as ancillary benefits such as gas abatement and tax credits. A brief discussion of these follows.

Cash sales of energy: electric power. Although electric power sales to the grid will be possible at the majority of sites, the revenue for power sold varies widely. The "averaged" power sale rate for continuous, constant-rate production that would occur uninterrupted over a year varies over the U.S. from a low of approximately 2 cents per kWh (areas such as the Pacific Northwest), to over 10 cents (Hawaii).

Avoided costs: electric power. When landfill-gas-generated electricity is used in lieu of utility power from the grid, electric utility retail costs are avoided. These "avoided cost" benefits are almost invariably higher than the price for which the power could be sold to the utility. Avoided costs may be from 25 percent to more than twice the price for direct sale of power to the utility depending on whether the utility requires capacity or has a large amount of expensive generation operating. Averaged avoided costs for a continuously generated electrical power stream consumed by a large user, depending on U.S. location, will typically lie between 4 and somewhat over 10 cents per kWh. In any case, the benefit will typically be greater than for sale to the grid.

Other energy sale prices. The sale price received for forms of energy other than electricity is typically set by the price of competing fuels. For example, at a current oil price of $20/barrel, or the equivalent pipeline gas cost of slightly over $3/1,000 cubic feet, the sale price realized for landfill gas might be near $3/1,000 cubic feet of methane content. In practice the sale price will vary depending on local price of competing pipeline gas, and other additional costs or effects specific to landfill gas, but the percentage variation in gas sale price across the U.S. would typically be much less than is true of electricity. If a product such as steam or hot water is sold, the price might be 20 to 50 percent higher on a Btu basis than the local price of competing fuels to reflect efficiency and cost of conversion.

Tax credit benefits. The Federal alternative energy tax credit is a benefit that may be available to an independent entity ("provider") owning and operating the gas system, and providing the energy to a user (user). The provider must be less than half owned by the gas user. A reduction of the provider's federal income tax, up to the provider's tax total, is obtained under a formula based on the price of oil. The credit is currently close to $0.85 per million Btus. Its effect on energy economics may be realized in various ways; it is most often realized through the provider's subsidy of costs for gas system construction and operation that would otherwise be a component of the energy cost. This is a major benefit, amounting to slightly over $0.01/kWh for electrical generation. It would appear to have facilitated a large number of projects.

Other miscellaneous benefits: gas system. Although the gas control system may be mandated by regulations whether or not the energy is used, it is often convenient for the entity operating the energy system to also participate in operating the gas system. This is because staff are available, and gas flow and composition need to be analyzed for both gas system and energy equipment operation. When this occurs, a major fraction of gas system operation costs that would otherwise be experienced (see above) can be avoided; the allocation of such savings is typically a matter of negotiation among project participants.

Total costs and overall economics

Total costs of a project including all components would be determined by summing capital, operating, and maintenance costs in categories above. Economics would be determined by comparing the total of these costs to the sum of the benefits. This report generally avoids presenting "the" economics by application, because of wide variation and also partly for lack of data; the specific case of reported capital costs of electric power facilities versus capacity has been addressed in the main text.

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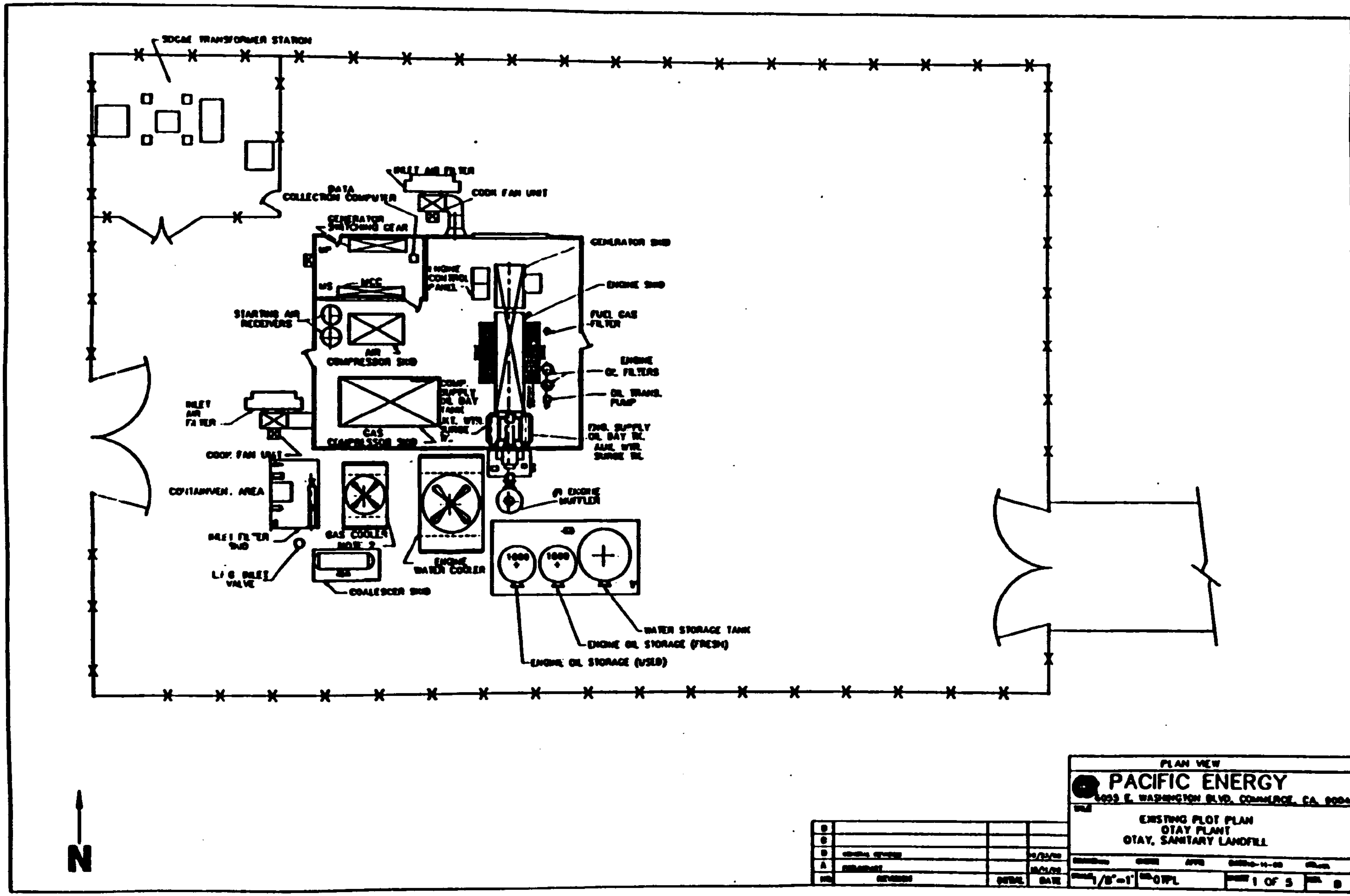
APPENDIX G

SITE LAYOUT, OTAY ELECTRIC GENERATION FACILITY



PACIFIC ENERGY

EQUIPMENT DETAILS, OTAY FACILITY, PACIFIC ENERGY

NAME OF PROJECT: Otay Power Station

OWNER: Pacific Energy

BRIEF DESCRIPTION:

The Otay Power Station, located in Southern California on the County of San Diego's Otay landfill in Chula Vista, generates electric power using gas recovered from the landfill. The landfill gas (containing about 47% methane) fuels a single internal combustion engine/generator to produce up to 1.7 megawatts (MW) of net power which is sold to San Diego Gas & Electric. The plant began operation in December 1986 and has a typical availability factor (on line time) of over 90% including scheduled maintenance.

KEY PROJECT DATA

- Project Location.............Otay, California
- Landfill Name ....Otay Sanitary Landfill
- Landfill Owner ....County of San Diego
- Gross Power..................1,900 KW
- On Site Power Use............5% to 10%
- Net Power to Grid............1,700 KW
- Power Purchaser..............San Diego Gas & Electric
- Equiv. Homes Served..........1,700 (maximum)
- Barrels of Oil Saved/yr......22,000 Barrels (maximum)
- Fuel Used....................Landfill Gas
- Landfill Size................525 Acres
- Landfill Depth...............90 feet (current average)
- Landfill Fill Rate ....500,000 tons per yr.
- Landfill Opened..............1966
- Landfill Closure.............beyond year 2000
- Number of Gas Wells..........Thirty-two
- Number of Engine-Generators..One
- Type of Engine ....Gas fired, internal combustion, 16 Cyl
- Type of Generator ....1,875 KW 4,160 Volt, synchronous
- Type of Transformer..........4,160 Volt to 12,000 Volt, step-up
- Project Start-Up.............December, 1986
- Project Life (Estimated).....20 years
- Project Operator/Owner.......Pacific Energy
- Project Employees Total......One
- Project Employees 1st Shift..One
- Project Employees 2nd Shift..Not required, automated operation
- Project Employees 3rd Shift..Not required, automated operation

XPANSION PLANS:

ne plant will be expanded to incorporate an additional engine-generator nd related equipment to double power output. Construction is to begin oout April 1st. Start-up is scheduled for summer 1991.

OTAY POWER STATION (Key Components)

MOTOR CONTROL CENTER (MCC)
Contains starters and controls for all electrical motors at the power plant. Including: Gas compressor, air compressor, gas cooler, water cooler, building fan, etc.

GENERATOR SWITCH GEAR PANEL
Houses instruments and controls for the plant's generator (4160 Volt, 3 phase, 60 Hz).

AUTOMATIC DIALER
Provides automatic "dial-up" or page alert notification to plant operators in the event of a plant shut-down. The system is programmed to provide a voice synthesized message alerting the operator which component initiated the shut-down.

DATA COLLECTION COMPUTER
Receives and stores information from the plant's gas chromatograph, as well as various transducers and thermocouples located throughout the plant. Computer compiles various information and reports on plant production. All data and reports produced at the plant can be accessed via a phone line link up to Pacific Energy's headquarters office.

AIR COMPRESSORS (2)
Provides compressed air to operate plant instruments, pneumatic valves, pneumatic pumps and for engine start-up.

GAS COMPRESSOR
Draws gas from landfill at a typical vacuum of 10" to 20" water column and discharges gas at 100 psig to the engine. Electrical motor driven. 150 horsepower. Two stage reciprocating.

ENGINE
Internal combustion. 16 cylinders. Turbocharged. 2650 Brake horsepower. 13,194 cubic inch displacement. 900 RPM. 85-90 psig inlet gas pressure.

ENGINE CONTROL PANEL
Houses instrumentation and controls for Cooper Superior "Clean Burn" engine.

GENERATOR
Produces 1875 Kilowatts at 4160 Volts. 3 phase. Single Bearing. Synchronous. 900 RPM.

GAS CYLINDERS
Contains Helium (Carrier gas) and reference gas mixture (Span gas), for calibrating the plant's gas chromatograph which measures and records the percent of Methane (CH_4), Carbon Dioxide (CO_2), Nitrogen (N_2), Oxygen (O_2); also calculates heating value (BTU/CF).

GAS FILTER -- INLET
Removes particulate and water from inlet gas to compressor.

ENGINE OIL FILTERS (2)
Filters designed to remove oil particulate down to 10 to 15 microns.

ENGINE OIL STORAGE (fresh oil)
Provides on-site bulk storage of fresh oil for the plant's internal combustion engine. 1600 gallon. Manually operated.

ENGINE OIL STORAGE (used oil)
Provides on-site storage of used oil from the plant's internal combustion engine. 1600 gallon. Manually operated.

WATER STORAGE TANK
5000 gallon capacity.

SUBSTATION
Owned and maintained by Pacific Energy. Steps-up voltage from Pacific Energy's power plant from 4160 Volts to 12,000 Volts to match SDG&E's transmission lines receiving the power. Station contains main transformer, auxiliary transformer, air switches, and power measurement meters.

Pacific Energy 6055 East Washington Boulevard, Commerce California 90040 (213) 725-1135 FAX (213) 725-8772

APPENDIX I

PG&E POWER PURCHASE RATES, MARINA

Pacific Gas and Electric Company

77 Beale Street
San Francisco, CA 94106
415/972-7000

ENERGY PRICES FOR QUALIFYING FACILITIES EFFECTIVE MAY 1, 1990 - JULY 31, 1990

The energy prices applicable to purchases by PG&E from qualifying facilities are shown below. They are the product of the weighted-average utility electric generation (UEG) natural gas rate and the Incremental Energy Rates plus an adjustment for the revenue requirement for Cash Working Capital, the Geothermal Adder and the Variable O&M Adder. The Incremental Energy Rates and the Variable O&M Adder were adopted by the California Public Utilities Commission in Decision 89-12-015. The Geothermal Adder was adopted in Resolution No. E-3139, dated July 19, 1989. The revenue requirement for Cash Working Capital is calculated in accordance with Decision 89-12-057. The average UEG gas rate is based on the most recently adopted forecast of UEG volumes in Decision 90-04-021, the current UEG transportation tariff as filed in Advice No. 1586-G and the natural gas commodity charge to core-elect customers on the date of posting.

	INCREMENTAL ENERGY RATE Btu/kWh** (1)	AVERAGE UEG RATE $/MMBtu (2)	REVENUE REQUIREMENT FOR CASH WORKING CAPITAL $/kWh (3)	GEOTHERMAL ADDER**** $/kWh (4)	VARIABLE O&M ADDER $/kWh (5)	ENERGY PURCHASE PRICE*** $/kWh (6)=[(1)x(2)]+(3)+(4)+(5)
WITH TIME-OF-DELIVERY METERING:*						
Peak	9.290	3.3532	0.00012	0.0004167	0.002326	0.034013
Partial-Peak	9.045	3.3532	0.00012	0.0004167	0.002326	0.033189
Off-Peak	8.542	3.3532	0.00011	0.0004167	0.002326	0.031495
Super Off-Peak	7.747	3.3532	0.00010	0.0004167	0.002326	0.028819
WITHOUT TIME-OF-DELIVERY METERING:						
Seasonal Average (Period A)	8.648	3.3532	0.00011	0.0004167	0.002326	0.031852

FOOTNOTES:

*

TIME PERIOD	MAY 1 - OCTOBER 31 (Period A)	NOVEMBER 1 - APRIL 30 (Period B)	
PEAK:	Noon - 6:00 p.m.	None	Monday - Friday, except holidays
PARTIAL-PEAK:	8:30 a.m. - Noon		Monday - Friday, except holidays
	6:00 p.m. - 9:30 p.m.	8:30 a.m. - 9:30 p.m.	Monday - Friday, except holidays
OFF-PEAK:	9:30 p.m. - 1:00 a.m.	9:30 p.m. - 1:00 a.m.	Monday - Friday, except holidays
	5:00 a.m. - 8:30 a.m.	5:00 a.m. - 8:30 a.m.	Monday - Friday, except holidays
	5:00 a.m. - 1:00 a.m.	5:00 a.m. - 1:00 a.m.	Saturday, Sunday and holidays
SUPER OFF-PEAK:	1:00 a.m. - 5:00 a.m.	1:00 a.m. - 5:00 a.m.	All days

(Holidays include New Year's Day, Washington's Birthday, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day.)

**Incremental Energy Rates are derived from PG&E's marginal energy costs.

***The energy purchase price excludes the applicable energy line loss adjustment factors. As ordered by Ordering Paragraph No. 12(j) of Decision No. 82-12-120, this figure is currently 1.0 for transmission and primary interconnection voltage levels, and for secondary distribution is as follows:

	Period A	Period B
Peak	1.0148	-
Partial-Peak	1.0131	1.0119
Off-Peak	1.0093	1.0087
Super Off-Peak	1.0093	1.0087

****On April 10, 1990, PG&E submitted Advice No. 1282-E-A to supersede Advice No. 1282-E and to propose a Geothermal Adder of $0.0004519/kWh. Advice No. 1282-E-A has yet to be approved by the CPUC. PG&E has requested specific CPUC authorization to apply the $0.0004519/kWh adder to energy payments for variable-priced energy purchased on and after May 1, 1990.

APPENDIX J

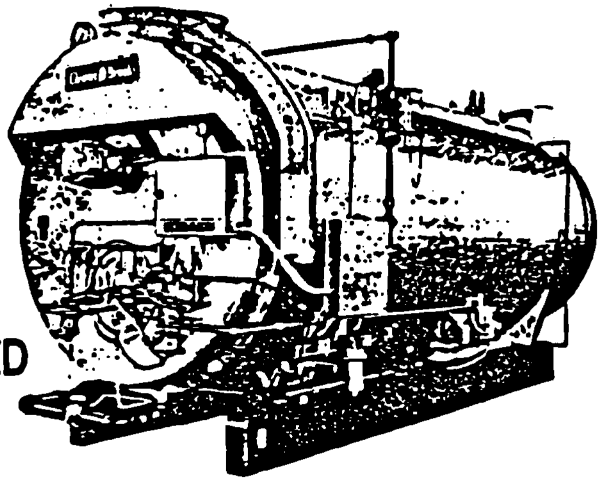
SPECIFICATIONS FOR CLEAVER-BROOKS BOILER

Cleaver-Brooks

MODEL **CB**® **Packaged Boiler**

STEAM OR HOT WATER

800 HP OIL, GAS OR COMBINATION FIRED



- COMPACT
- EFFICIENT
- PERFORMANCE PROVED

UNEQUALED FUEL ECONOMY: Four pass, forced draft construction; efficient burner design:

Guaranteed minimum 80% fuel-to-steam efficiency from 25 to 100% of rating on either gas or oil fuels.

Guaranteed minimum fuel-to-steam efficiency at 100% of rating is 82.0% with gas firing and 83.0% with oil firing.

EASY MAINTENANCE: Hinged or davited doors; modular control panel, retractable burner nozzle.

QUIET: Sound levels are lower than strict hospital and school standards due to unique caseless fan design. Less than 88 db in high fire — less than 85 db in low fire when measured on the "A" scale.

HEATING SURFACE: 3500 sq. ft. on the fireside — 3800 sq. ft. on the waterside.

AUTOMATIC, SAFE: Eye level control panel; centralized combustion controls; modulated firing; electronic flame safeguards.

FUEL CONTROL: Precise metering of fuel via special metering cam.

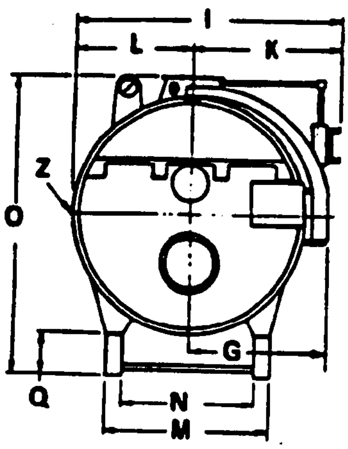
AIR CONTROL: Unique rotary damper for accurate metering of combustion air.

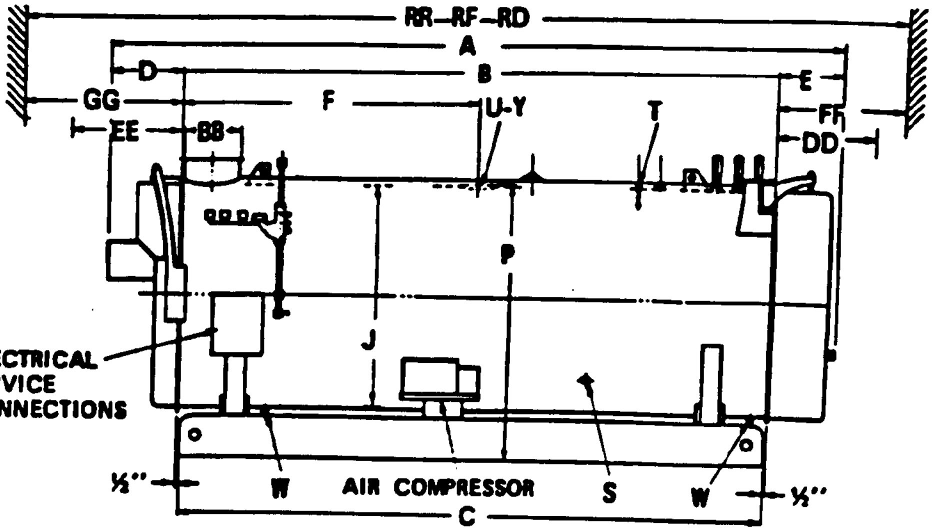
CLEAN FIRING: Accurate air-fuel ratios throughout the modulating range. CB designed air compressor, and efficient oil or gas burner design.

PACKAGED: A complete unit from a single source. Cleaver-Brooks designs, builds, tests and ships to your job site ready for quick hook-up. Starting service assures peak on-the-job performance.

STEAM BOILERS DIMENSIONS AND RATINGS

(15 LB. AND 150 LB. STEAM)





NOTE: DIMENSIONS MUST BE CONFIRMED FOR CONSTRUCTION

LENGTH

Overall	A	25'-11"
Shell	B	21'- 3"
Base Frame	C	21'- 2"
Front Head Extension	D	29"
Rear Head Extension	E	27"
Front Ring Flg. to Nozzle (15 & 150 lb.)	F	128"

WIDTHS

Overall	I	116"
I. D. Boiler	J	96"
Center to Water Column	K	65"
Center to Lagging	L	51"
Base, Outside	M	72"
Base, Inside	N	58"
Center to Outside Hinge	G	62"

HEIGHTS

Overall	O	10'- 8"
Base to Steam Outlet	P	9'-10"
Height of Base	Q	18"

BOILER CONNECTIONS

Feedwater, Right and Left	S	2½"
Auxiliary Connection	Z	1¼"

Low Pressure (15 lb. only)

Steam Nozzle	U	12"FL †
Drain, Front and Rear	W	2"

High Pressure (150 lb. only)

Surface Blowoff, Top C	T	1"
Steam Nozzle	Y	8"FL ††
Blowdown, Front and Rear	W	2"

Connections threaded unless indicated – Fig. † – 150 lb. ANSI
Fig. †† – 300 lb. ANSI

VENT STACK

Diameter (flanged connection)	BB	24"

MINIMUM CLEARANCES

Rear Door Swing	DD	4'- 5"
Front Door Swing	EE	9'- 0"
Tube Removal, Rear	FF	19'-10"
Tube Removal, Front	GG	18'- 4"

MINIMUM BOILER ROOM LENGTH DOOR SWING AND TUBE REMOVAL

Rear of Boiler	RR	50'-1"
Front of Boiler	RF	44'-0"
Thru Window or Doorway	RD	34'-8"

WEIGHT IN POUNDS

Normal Water Capacity	27,790
Approx. Ship. Wgt. 15 lb.	52,000
Approx. Ship. Wgt. 150 lb.	53,600
Approx. Ship. Wgt. 200 lb.	56,600

CAPACITY

Rated capacity in lbs. steam/hr. (212 F)	27,600
BTU output (1000 BTU/hr.)	26,780
EDR steam gross	111,600

FUEL CONSUMPTION

Gas CFH	
1000 BTU-natural	33,500
Gas (therms per hr.)	335.0
Light Oil GPH	239
Heavy Oil GPH	223

POWER REQUIREMENTS

Blower motor	50 HP
Oil Pump – Light Oil	1 HP
Oil Pump – Heavy Oil	¾ HP
Air Compressor (Oil Firing Only)	7½ HP

MINIMUM REGULATED GAS PRESSURE

Standard Train	73" WC
IRI Train (Former FIA)	73" WC
FM Train	73" WC

GUARANTEES AND TESTS

:FICIENCY – The CB 800 HP packaged boiler is guar-d to operate at a minimum fuel-to-steam efficiency of r greater over the operating range.

:OP TESTS – The packaged boiler shall receive factory by the manufacturer to check construction and ion.

All tests may be witnessed by purchaser at his own expense and upon sufficient notice.

3. STARTING SERVICE – After boiler installation is completed, a field representative will start the boiler and train the operator. This service is not to exceed two consecutive days. Any additional starting instruction or service required by the purchaser or ultimate owner will be charged at prevailing rates.

Extra service time requested by the purchaser or caused by incomplete installation work or other factors not a part of the Company's responsibility will be charged to the purchaser at prevailing rates for labor and expense.

August 1990

UNITED KINGDOM CASE STUDIES

BEST PRACTICE PROGRAMME

New Practice—Final Profile 19

ELECTRICITY GENERATION USING LANDFILL GAS

Project Objective

To demonstrate the feasibility, energy saving and commercial advantages of using landfill-gas-fuelled spark ignition engines to generate electricity in parallel with the national distribution network.

Potential Users

Remote or rural landfill sites without easy access to direct consumers of landfill gas.

Investment Cost

Stewartby: £418,500
Replicators: £464,000
(1987 prices)

Savings Achieved

Stewartby: £158,000/year
Replicators: £99,400 — £118,900
(1987 prices)

Payback Period

Stewartby: 2.4 years
Replicators: 3.2-4.7 years

Project Summary

In this project, three 275 kW spark ignition engines fuelled by landfill gas were installed at a landfill site at Stewartby in Bedfordshire. They are used to generate over 6.6 million kWh/year of electricity, the power generated being sold at peak periods to the London Brick Company system and at other times to Eastern Electricity. A small proportion of the power was used in-house. The project was prompted both by the incentive to harness the energy in the environmentally controlled landfill gas at the site and by the success of early on-site experiments with the use of landfill gas for power generation.

Host Organisation

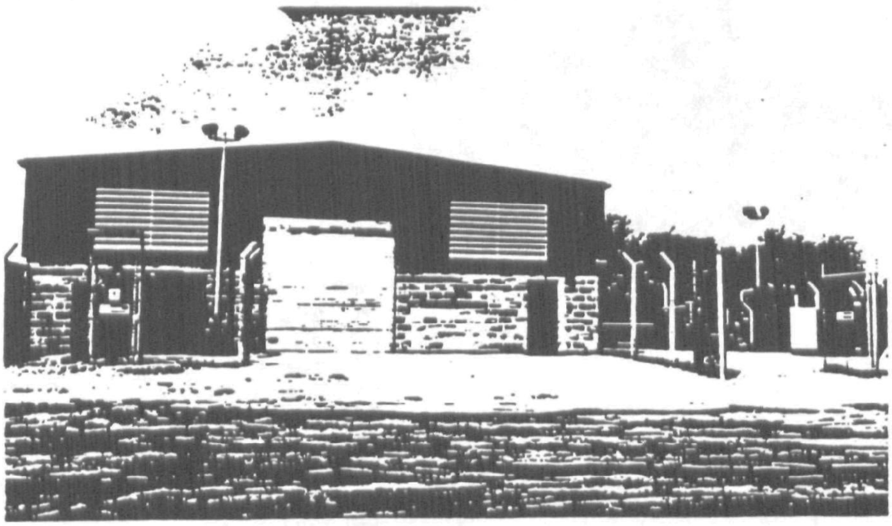
Shanks & McEwan (Southern) Ltd
Woodside House
Church Road
Woburn Sands
Milton Keynes
MK17 8TA

Monitoring Contractor

Ewbank Preece Ltd
Prudential House
North Street
Brighton
Sussex
BN1 1RZ
Tel No: 0273 724533
Telex No: 878102
Mr M R Hornsby

Equipment Manufacturer

Dorman Diesels Ltd
Tixall Road
Stafford
ST16 3UB
Tel No: 0785 223141
Telex No: 31656
Fax No: 0785 215110
Mr D L Jones
Mr J J Lusby



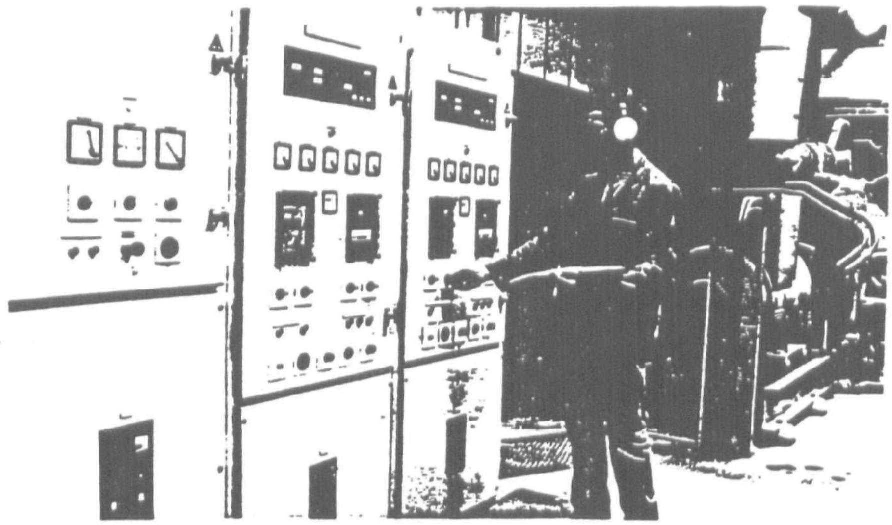
Landfill gas power generation facility and abstraction plant

Energy Efficiency Office
DEPARTMENT OF ENERGY

The Stewartby Site

The Stewartby site of Shanks & McEwan (Southern) Ltd (SMS) occupies a total of 74 ha and had an original void volume of 10 million m^3. It receives approximately 1,000 tonnes of waste per day transported by rail from London, together with some local waste. Adjacent to the site is the London Brick Company (LBC) Stewartby brickworks which produced about 12 million bricks/week in 1987.

SMS's initial involvement in the development of landfill gas extraction in 1979 led to gas from five wells being used to fire bricks in a nearby LBC kiln. This was followed by an early study of the feasibility of electricity generation based on a Rolls-Royce B81G 8-cylinder gas engine driving a 75 kVA generator.



Control panel

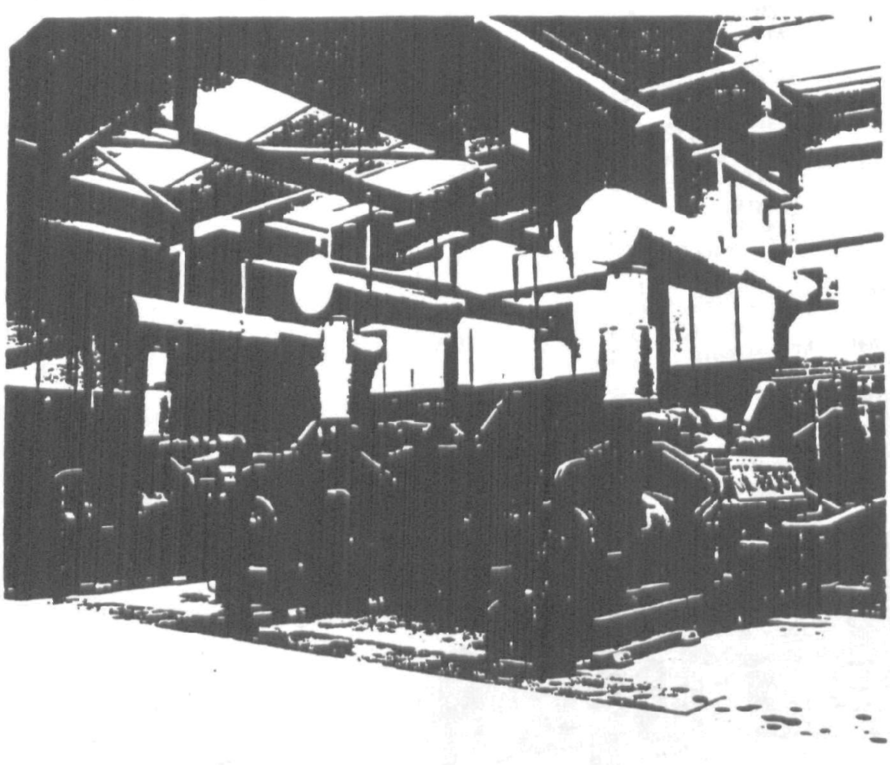
Development

The success of the initial electricity generation trials led to the installation of three Dorman type 12STCWG spark ignition engines coupled to air-cooled generators.

Both vertical and horizontal wells have been installed to extract the landfill gas, and more are planned for the future. Knock-out drums for water removal are located in each of the polyethylene lines from the landfill site, two on the longer (500m) line and one on each of the other lines. The gas is passed through pre-filters prior to compression.

The compressor, a single, constant displacement vane-type unit manufactured by Hammond Engineering Ltd, is driven by a 45 kW electric motor. It is rated to supply 680 m^3/h against 1.3 bar g. The compressed gas passes through an aftercooler, baffle water separator, chiller and fine filters before being supplied to the adjacent engine house. Any surplus gas is flared.

Each turbo-charged, 4-stroke, 12-cylinder, Vee-form engine unit is rated at 275 kW output at 1000 rpm when running on landfill gas. Because of the lower calorific value of this fuel, the rating quoted is some 11% below the engine's normal rating when operating on natural gas. The units are cooled by radiators mounted on the same framework as the engines, and the air used is drawn from outside the engine room. Twin, paper element air filters are provided for each cylinder bank, and each engine is fitted with a single exhaust ducted horizontally to exit through the engine-room wall.



Dorman diesel engines

The engines are directly coupled to Newage Stamford air-cooled generators. These are rated at 350 kVA and generate at 415 V. The entire generation plant is housed in a single-roomed engine house which also contains control panels and the lubricating oil tank. The units are designed to operate unattended, so comprehensive interlocks are provided to trip the units in the event of low gas pressure, spit-back in the carburettor, low oil pressure, high engine temperature or engine overspeed. All engine trip circuits are linked by telephone to a 24-hour call-out system.

Electricity is supplied at 415 V for in-house use and a small proportion of the power exported is supplied at the same voltage to LBC. The main export power is, however, stepped up to 6.6 kV via a single transformer. During the daytime all this power is taken by the LBC system. LBC have a peak power consumption of about 5.6 MVA during the daytime when the brickworks are in operation. Overnight and at weekends, however, their load falls to a minimum of about 300 kW. As landfill gas cannot be stored economically, the generating plant at SMS is operated continuously, and the balance of power generated during periods of low demand is exported to Eastern Electricity at 33 kV.

Plant Performance

The gas compressor has operated almost continuously since February 1987. During that time there has been a failure in the oil supply, requiring a new electric oil pump, and three compressor failures resulting from water getting through the water separation systems. These failures required compressor replacement or rebuild in each case and action has been taken to prevent any recurrence. Three subsequent failures (for different reasons) were also rectified and the compressor has operated without major problems since the last quarter of 1988.

The generators have run almost continuously apart from major service shutdowns and minor faults. Most of the faults were electrical and were rectified by adjustments to equipment. There have been few problems with the use of landfill gas as a fuel, although low methane content has occasionally caused the units to trip. A typical methane content in the gas during the early stages of monitoring was 50%. This has since increased to 58% after rectification of air leakages in the gas collection pipework.

The generation units have shown consistently high service factors (94-95% for Units 1 and 3 and 93% for Unit 2). The engine service at 22,000 hours showed the engines to be in generally good condition with only minor problems of wear.

Annual Power Generation and Distribution

Based on operation to date and an annual capacity factor of about 91.5%, annual power generation is assessed at 6,612,705 kWh year.

This total comprises

- exports to LBC: 4,827,275 kWh/year (73%);
- exports to Eastern Electricity: 925,779 kWh/year (14%);
- internal consumption: 859,652 kWh/year (13%).

Approximately 23% of internal consumption (198,381 kWh/year) is used in SMS's own offices on site and represents a saving to SMS who no longer have to import from Eastern Electricity.

Income from Electricity Sales

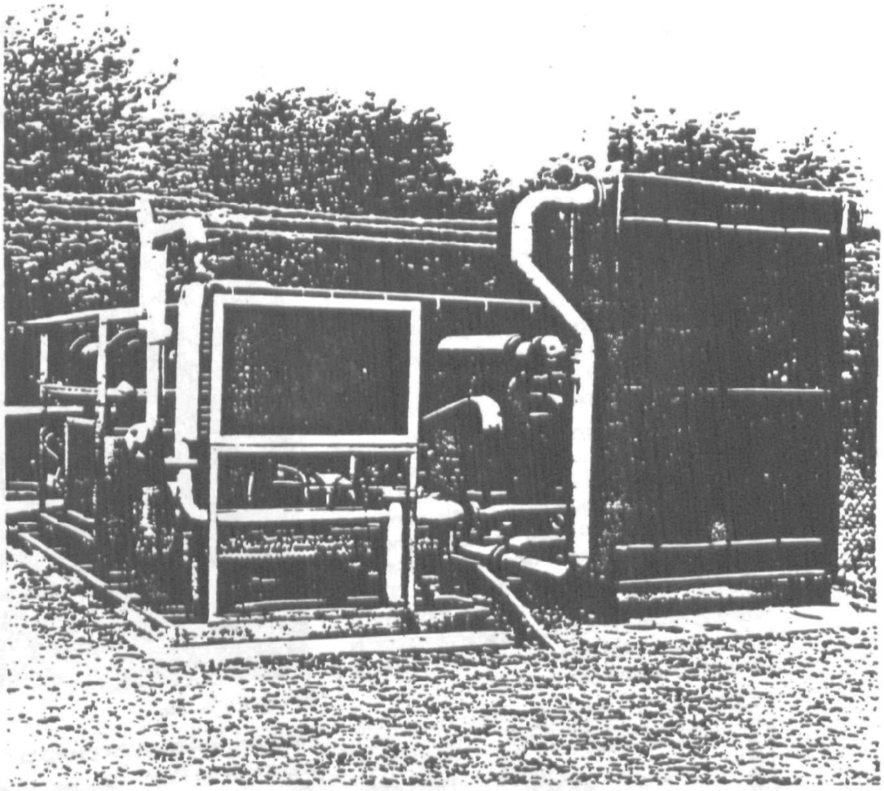
Sales to LBC at a rate of 2.93p/unit total £141,439/year.
Sales to Eastern Electricity at a rate of 2.36p/unit total £21,848/year.

The additional money available to SMS from savings on imported electricity amounts to £6,467/year giving a total income of £169,754/year.

A further identifiable saving derives from the fact that, if SMS did not have a power generation project, they would still need to flare the landfill gas. This would involve a compressor and the power to drive it which, in this particular location, would cost about £48,000/year.

Allowing for operating and maintenance costs of £59,800/year, total net income and savings at the Stewartby site amount to £157,954/year.

The capital cost of the project was £418,470. For the purposes of this analysis, the cost of the compressor (£36,650) has been excluded from the total cost as this would be required anyway to flare the gas. Based on the resulting investment cost of £381,820, the simple payback is 2.4 years.



Gas abstraction plant

Financial Benefits to Replicators

Assuming that 90% of the units generated (5,951,435 kWh/year) are exported at an average tariff of 2.75p/unit, the annual income would be £163,664/year. Additional savings made against the hire and operation of a portable generator for the compressor amount to £15,000/year in the case of a replication site with a suitable power supply. Operating and maintenance costs remain at £59,800/year. Net annual income is therefore £118,864/year, giving a payback period on a £381,820 capital cost of 3.2 years.

For a replicator for whom gas control is not a prerequisite, no allowance can be made against the portable generator for the compressor, and an additional figure of £4,500/year must be added for operation and maintenance. This gives a net annual income of £99,364/year. SMS estimate that, prior to the start of this project, £45,500 had already been spent on the gas collection system and associated wells. If this figure and the cost of the compressor is charged to the project, then the capital cost to the replicator would be £463,970 giving a payback period of 4.7 years.

Combined Heat and Power Generation Potential

The engines at Stewartby operate purely as power generation units. However, the potential does exist for heat recovery from the plant both as steam from waste heat boilers on the exhaust and as hot water from the cooling water circuits.

Estimates from Dorman indicate that, at full load and allowing for losses, about 110 kW could be recovered from each engine's exhaust. Using an 85% capacity factor, the total heat energy available from the three engines would amount to 8,850 GJ/year.

A further 260 kW would be available from the cooling circuit equivalent to 20,900 GJ/year. The recovery of this low-grade heat (at about 70°C) would depend on an appropriate demand being available.

The cost of generating the 29,750 GJ in either gas or gas oil-fired boilers operating at 75% efficiency would be £2.50/GJ. A combined heat and power generation system would therefore save a further £100,000/year (£30,000/year if heat from the exhaust systems only was recovered) and would reduce the payback period to 1.5 years (2.0 years). These figures make no allowance for the capital, operating and maintenance costs of waste heat boilers.

	Stewartby	**Replication site without gas system**	**Replication site with gas system**
Annual power generation (kWh/year)	6,612,705	6,612,705	6,612,705
Exports (kWh/year)	5,753,053	5,951,435	5,951,435
Internal consumption (kWh/year)	859,652	661,270	661,270
Income from power sales	£169,754	£163,664	£163,664
Operating and maintenance costs	£(59,800)	£(59,800)	£(64,300)
Savings on portable generator for compressor	£48,000	£15,000	
Net annual income	**£157,954**	**£118,864**	**£99,364**
Capital cost	**£381,820**	**£381,820**	**£463,970**
Simple payback	**2.4 years**	**3.2 years**	**4.7 years**

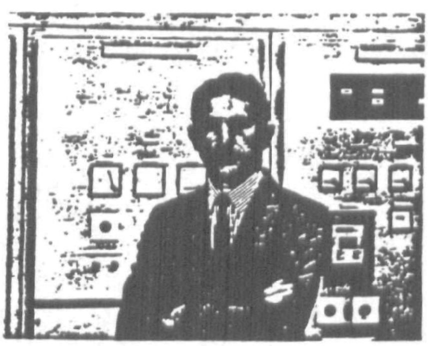
Comments from Shanks & McEwan

Environmental landfill gas abstraction is the duty of every company disposing of wastes. The gas which is collected must be used usefully or disposed of to render it as harmless as possible.

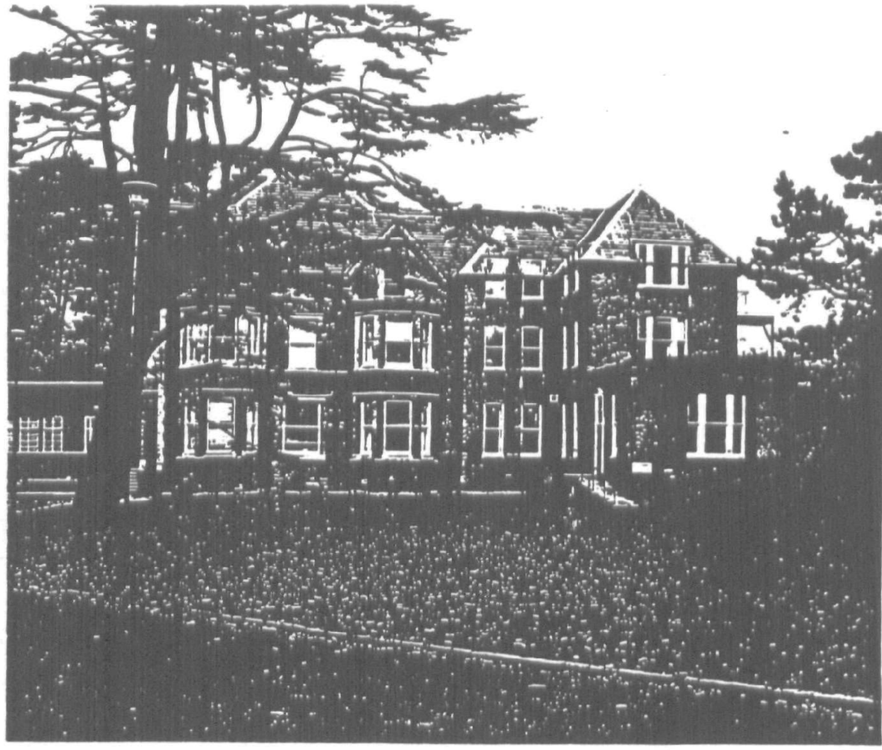
Shanks & McEwan have been in the forefront of the commercial use of landfill gas, starting with brick kiln firing in 1981 and electricity generation in 1984.

The development of the landfill site at Stewartby required the installation of equipment to flare large quantities of landfill gas. There was no adequate electrical supply available and, at first, a diesel-powered generator was used to produce the electricity. When larger quantities of electricity were required, the current project became financially feasible because of savings made by substitution of the diesel generator as well as income secured from the sale of electricity.

This project, which generates 1,100kW using spark ignition engines, is the second stage in the company's strategy for the conversion of landfill gas to electricity. It has shown that a number of engines can be operated in parallel and run unattended for 24 hours a day but still operate to a high level of efficiency. With over 100,000 operating hours achieved we are confident in pressing forward with plans to generate electricity at all company landfill sites which have commercial quantities of landfill gas available.



Mr H D T Moss
Technical Director
Shanks & McEwan (Southern) Ltd.



Woodside House

Shanks & McEwan (Southern) Ltd

Shanks & McEwan (Southern) Ltd (formerly London Brick Landfill) operate a number of landfill sites in former quarries of the London Brick Company. These sites cover a total area of some 1,300 ha with a nominal volume of 130 million m^3. The company has been closely involved in the development of landfill gas extraction since 1979 and has conducted a number of projects both with the Department of Energy and the Department of the Environment.

The work described here was carried out under the Energy Efficiency Demonstration Scheme. The Energy Efficiency Office has replaced the Demonstration Scheme by the Best Practice programme which is aimed at advancing and disseminating impartial information to help improve energy efficiency. Results from the Demonstration Scheme will continue to be promoted. However, new projects can only be considered for support under the Best Practice programme.

More detailed information on the Shanks & McEwan project is contained in the final report NP/19.

For copies of reports and further information on this or other industrial projects, please contact: Energy Efficiency Enquiries Bureau, Energy Technology Support Unit (ETSU), Building 156, Harwell Laboratory, Oxon OX11 0RA. Tel No: 0235 436747. Telex No: 83135. Fax No: 0235 432923.

For information on buildings-related projects, please contact: Enquiries Bureau, Building Research Energy Conservation Support Unit (BRECSU), Building Research Establishment, Garston, Watford WD2 7JR. Tel No: 0923 664258.

Information on participa

Energy Efficiency Office
DEPARTMENT OF ENERGY

For further information contact:
Energy Efficiency Enquiries Bureau
Energy Technology Support Unit (ETSU)
Building 156, Harwell Laboratory, Didcot, Oxon OX11 0RA
Tel No: 0235 436747 Telex No: 83135 Fax No: 0235 432923

FEBRUARY 1991

Energy Efficiency Demonstration Scheme
Expanded Project Profile 249

Electricity From Landfill Gas Using Gas Turbines

A demonstration of the use of gas turbines to generate power in the waste disposal industry

Potential users
Medium-large scale landfill waste disposal operations.

Investment cost
£1,946,000 (1986 prices).

Payback period
11 years.

Savings achieved
57,795 GJ per year valued at £176,780 per year.

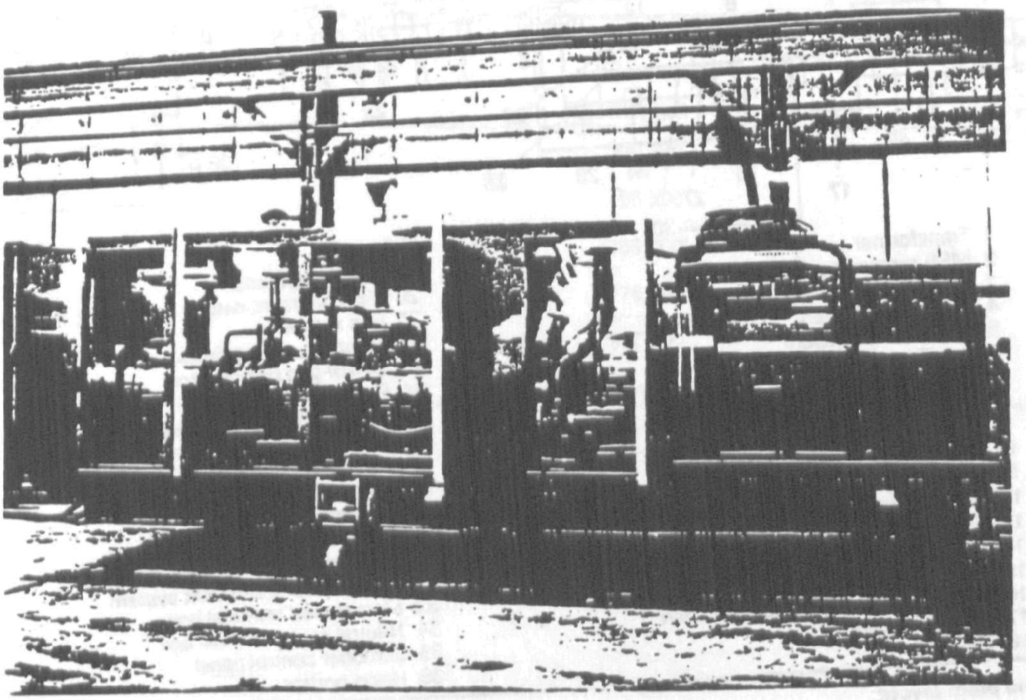
Host company
BFI Packington Ltd
Packington Hall
Packington Park
Menden
Coventry
CV7 7HF
Tel No: 0676 22155

Monitoring contractor
Ewbank Preece Ltd
Prudential House
North Street
Brighton
BN1 1RZ
Tel No: 0273 724533
Mr M Hornsby

Equipment suppliers
(Gas turbine generator set)
Centrax Ltd
Gas Turbine Division
Shaldon Road
Newton Abbott
Devon
TQ12 4SQ
Tel No: 0626 52251 Telex No: 42935
Mr A R Stallard

(Compressors)
Belliss and Morcom
Icknield Square
Birmingham
B16 1QL
Tel No: 021 454 3531 Telex No: 337507
Mr B Lamb

The aim of the project
Most of Britain's waste is disposed of in landfill operations. As the organic waste contained in a landfill site decomposes, landfill gas, mainly a mixture of methane and carbon dioxide, is produced. This gas is noxious, inflammable and can be explosive, and it is recommended that the gas is collected and burnt. The aim of the project was to demonstrate the commercial viability of burning landfill gas in a gas turbine, which could be used to generate electricity. The project also investigated the requirements to pre-treat the gas prior to combustion in the gas turbine, and the extent of any environmental impact from such a project.



Centrax turbine

How energy was saved

Approximately one million tonnes of waste from Birmingham and Solihull is disposed of every year in the Little Packington landfill site, midway between Birmingham and Coventry. The landfill site is 380 acres in area, and by 1987 contained about six million tonnes of controlled waste. Landfill gas seepage was a nuisance anc as initial boreholes produced gas with a methane content of 60%, it was decided to install a 3.65 MW gas turbine to generate electricity for direct export to the Midland Electricity Board (MEB). The project was supported under the Energy Efficiency Demonstration Scheme.

Landfill gas is supplied to the generation plant compound via 1,500 metres of buried pipe. The gas is scrubbed and passes through a centrifugal blower before being compressed in two Belliss and Morcom WH56N compressors. Each compressor is rated at 55% duty, although each is capable of delivering 70% of the total gas requirement when operated with the blower.

Before delivery to the turbine, the gas is cooled and superheated to control condensation of hydrocarbons. The 3.65 MW generator set is a Centrax model CX 350 KB5 powered by a General Motors Allison 501 KB5 single-shaft gas turbine which runs at 14,250 rpm. The drive to the Brush 6.125 MVA generator is taken through a step-down gearbox to 1,500 rpm. The generator output is exported to the MEB at 11kV via a 1.8 km long underground cable.

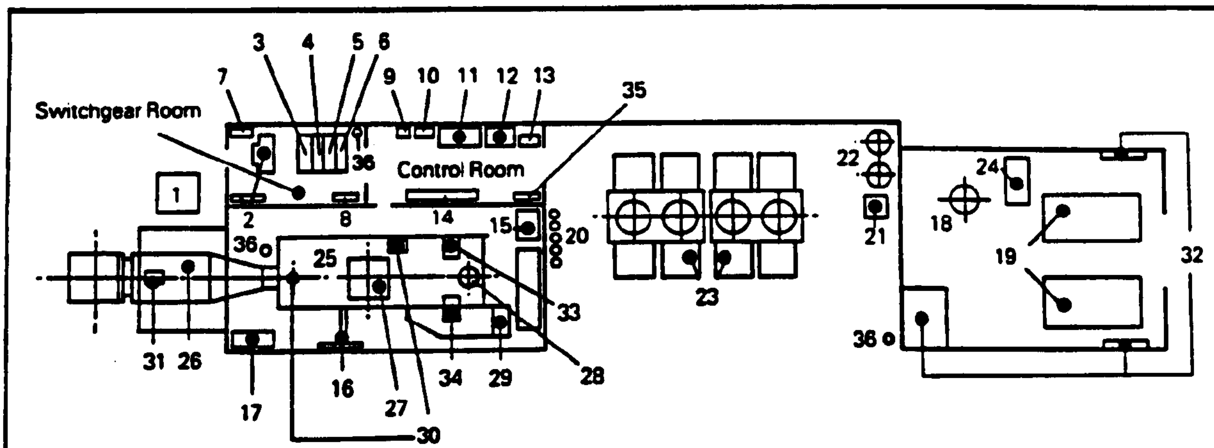
The turbine first ran on landfill gas on 23rd September 1987. During the plant acceptance trials the automatic condensate return valves were not functioning. The valves were removed and cleaned and, after reinstallation, functioned correctly. During commissioning, the No 2 compressor failed and the replacement unit also failed. With this compressor out of service, most of the operation during the period to January 1988 was undertaken using No 1 compressor supplemented by the gas blower. Under these conditions, it was possible to raise the turbine output to about 2.7 MW.

During early running of the compressor, the cylinder head and valves suffered fouling by chloride salts and hydrocarbons. In late December 1987 heavy corrosion was noticed in the stainless steel flexibles connecting to the compressor. The fouling and the corrosion were traced to the scrubber liquor which was being dosed with sodium hypochlorite and sodium hydroxide. The dosing was thought necessary to remove any hydrogen sulphide present in the landfill gas. Unfortunately, it is likely that the sodium hypochlorite also reacted with hydrocarbons to produce hydrogen chloride. Following advice from the manufacturers, dosing with sodium hypochlorite was stopped.

In November 1987, to prevent belling which had been reported on similar plant in the USA, replacement ends of the turbine fuel manifold were manufactured. Three serious failures occurred on the gas turbine, all involving the fracture of one of the gas injection nozzles. All six nozzles were replaced in October 1988 and a further redesign is in hand. Spurious trips of the turbine occurred towards the end of 1987 and into early 1988 which were mainly caused by the scrubber control panel, which has since been replaced.

As a consequence of these initial problems the system operated with an availability of 85% and at a reduced average output of 58%. However, since early 1988 the system has proved reliable and has achieved near continuous running. In the period June 1989 – May 1990 the system has been running with an availability of 95% while operating at 79% of rated output.

All the monitored exhaust emissions have been lower than the limits allowed for municipal waste incinerators, except in one instance when the HCl level emitted would have marginally failed to comply with the EC limit allowed. The noise level measurements taken at the site have indicated that, at a distance of 50 m, the noise was inaudible above the total background noise, even at night.



1 Transformer
2 MEB metering panels
3 Mains circuit breaker
4 Auxiliary C/B (Tran)
5 Generator C/B (Gen)
6 Generator II C/B (Future)
7 MEB trip circuit power supply
8 Switchgear (48V) power supply
9 Batteries (24V)
10 Battery charger panel (24V)
11 Turbine control panel
12 Generator control panel
13 Gas compressor panel
14 Motor control centre
15 Neutral earthing transformer and contactor
16 Demountable engine removal beam
17 Air compressor
18 Gas receiver
19 Gas compressor
20 High pressure natural gas bottles (for starting only)
21 Gas scrubber
22 Scrubber dosing tanks
23 Cooler-gas compressor
24 Booster
25 CX350 KB5 generator set
26 Turbine exhaust system
27 Turbine air intake system
28 Oil cooler vent system
29 Alternator vent system
30 Turbine enclosure vent system
31 Generator room vent system
32 Compressor room vent system
33 Main cables terminal box
34 Neutral cable terminal box
35 Scrubber control panel
36 Halon bottles

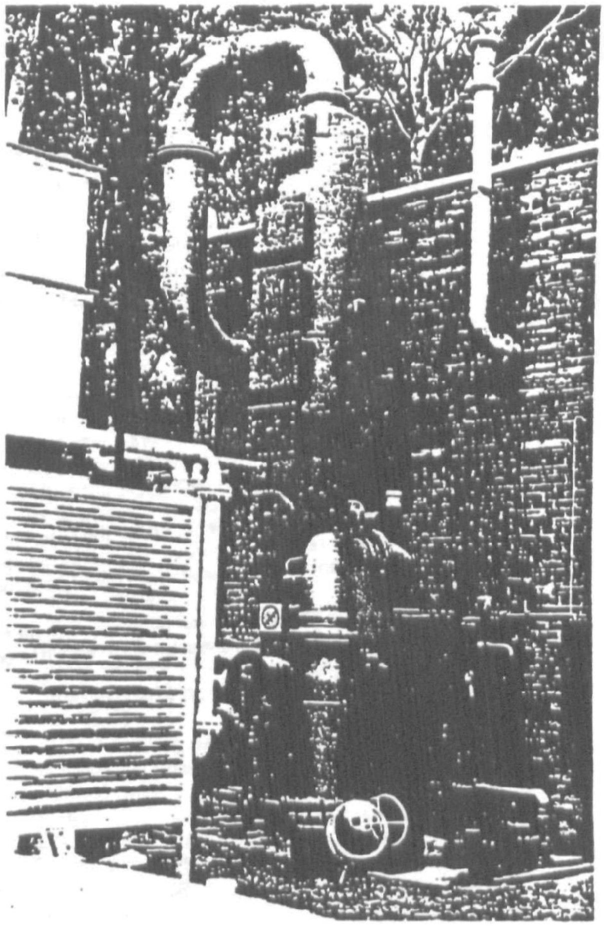
Gas turbine plant layout

Energy and cost savings

The total capital cost of the project at October 1986 prices was £1,946,000. In addition to this amount, expenditure was required for the installation of the gas collection system. Since this expenditure was necessary to control the gas hazard, the cost of these items has not been considered for this particular project. On replica sites, a gas collection system may be installed solely for the purpose of collecting gas for the generation of electricity. Therefore, in the following analysis two alternative cases have been considered: one with the additional figure of £300,000 has been allowed to cover the cost of collection equipment.

If the project had not been undertaken, costs of £55,500 involved in controlling the landfill gas would still have been incurred. This is displaced expenditure and may be considered as income for the Packington site. Considering these points, the table compares the economics of the Packington site with a replica site without a gas collection system.

The figures in the table are based on the measurements taken during the monitoring period October 1987 – May 1989 which includes the early operation of the plant when availability was relatively low. From June 1989 to May 1990 a further 8,760 hours of operation were completed at improved efficiencies. If the plant had achieved target generation with the original electricity tariff, this payback would be reduced to 4.5 years. Centrax has since sold another unit to operate solely on landfill gas. This installation enjoys a Comprehensive Maintenance Contract with guaranteed availability. The cost of the contract is significantly less than the O&M figures quoted in this profile. The use of landfill gas as a fuel to generate electricity is of considerable benefit to the nation. Not only does it contribute to the security and diversity of supply within the Non-Fossil Fuel Obligation, but also helps towards environmental control of landfill sites.



Gas scrubber

	Packington	Replica site with no gas collection system
Income from electricity sales	380,280	380,280
Displaced expenditure	55,500	—
O & M costs	(259,000)	(259,000)
Net annual income	176,780	121,280
Capital costs	1,946,000	2,246,000
Simple payback	11.0 years	18.5 years

BFI Packington Ltd

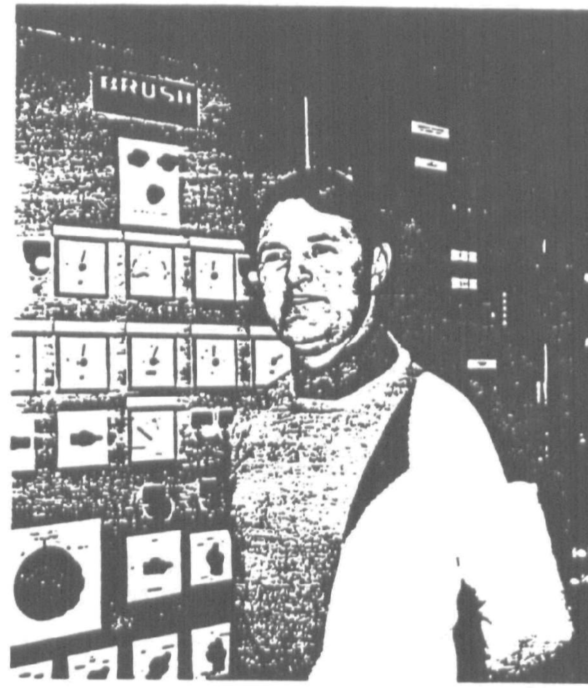
BFI Packington Ltd is an American-owned company operating a landfill site at Little Packington, between Birmingham and Coventry on part of the estate of the Earl of Aylesford.

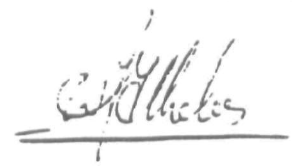
Comments from BFI Packington Ltd

The primary objective of this project was to control the potential hazard of landfill gas. Initial investigations were carried out on site to determine the extent to which landfill gas was being produced. This investigation proved that there would be substantial volumes of gas to handle. It was decided at this stage that there would be sufficient gas to support the operation of a gas turbine. The company's preference lay with a gas turbine due to the good combustion that a gas turbine produces and hence low exhaust emission levels.

The initial operation of the generating station proved troublesome. These teething problems resulted in relatively low plant availability during the early days. Once these problems were resolved, the plant managed to give a high level of availability. The plant is now capable of giving 97% availability and is burning 2.5 million cubic feet of gas per day. This high availability coupled with benefits under the Non-Fossil Fuel Obligation have served to improve the economic results of the project. The economics are now more favourable than original estimates.

At the end of the day, this project has proved to be a resounding success and we are all very pleased with what has been achieved.





Mr T Uncles
Consultant Gas Engineer to
BFI Packington Limited

Further Information

The work described here was carried out under the Energy Efficiency Demonstration Scheme. More detailed information on this project is contained in the final report ED/296/249. The Energy Efficiency Office has replaced the Demonstration Scheme by the Best Practice programme which is aimed at advancing and disseminating impartial information to help improve energy efficiency. Results from the Demonstration Scheme will continue to be promoted. However, new projects can only be considered for support under the Best Practice programme.

For copies of reports and further information on this or other projects, please contact the Energy Efficiency Enquiries Bureaux at either:

Energy Technology Support Unit (ETSU)
Building 156
Harwell Laboratory, Oxon OX11 0RA
Tel No: 0235 436747 Telex No: 83135
Fax No: 0235 432923

or the

Building Research Energy Conservation Support Unit (BRECSU)
Building Research Establishment
Garston, Watford WD2 7JR
Tel No: 0923 664258 Telex No: 923220
Fax: 0923 664097

Information on participation in the Best Practice programme and on energy efficiency generally is also available from your Regional Energy Efficiency Office.

Energy Efficiency Office

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For further information contact
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Energy Technology Support Unit (ETSU)
Building 156, Harwell Laboratory, Didcot, Oxon OX11 0RA
Tel No: 0235 436747 Telex No: 83135 Fax No: 0235 432923

JANUARY 1988

Energy Efficiency Demonstration Scheme

Expanded Project Profile 217

The use of Landfill Gas as a Replacement Fuel in a Shell Boiler

A demonstration of reduced conventional fuel consumption in the food industry

Potential users
Shell boiler operators within a 10 km radius of a landfill site

Investment cost
£140,743 (including boiler replacement)
£50,000 approximately (burner replacement only)

Payback period
3.0-6.6 years (including boiler replacement)
1.1-2.3 years (burner replacement only)
(both dependent on the fuel discount rate)

Savings achieved
£21,464-£47,170/year (dependent on the fuel discount rate)
(1986 prices)

Host company
Premier Brands UK Ltd
Pasture Road
Moreton
Wirrall
Merseyside L46 8SE

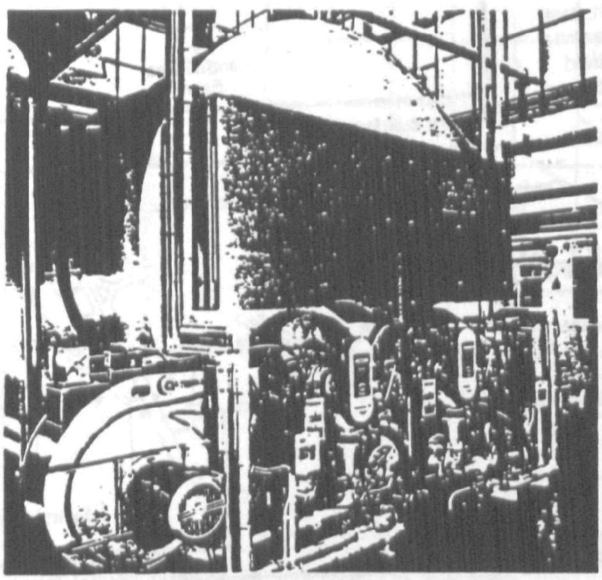
The aim of the project
In this demonstration, landfill gas produced at a landfill site on the outskirts of Birkenhead was piped some 2.75 km to a Premier Brands factory producing biscuits and other food products. The gas was used in conjunction with natural gas and heavy fuel oil to fire a new shell boiler to provide steam for central heating and process use. The aims were to show that unrefined landfill gas could be used to fire a shell boiler, to determine whether it would increase the risk of chemical corrosion and to assess the environmental acceptability of flue gas emissions. The consumer benefitted financially from the lower price of landfill gas compared with natural gas.

Monitoring contractor
NIFES
NIFES House
Sinderland Road
Broadheath
Altrincham
Cheshire WA14 5HQ
Tel No: 061 928 5791
Telex No: 669069
Mr G Davies

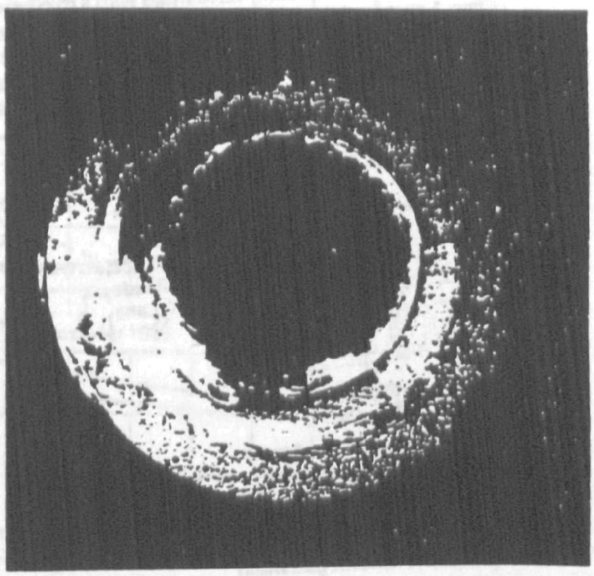
Equipment manufacturers
BURNERS
Hamworthy Engineering Ltd
Combustion Division
Fleets Corner
Poole
Dorset BH17 7LA
Tel No: 0202 675123
Telex No: 41226
Mr A G Parrott

BOILER
Wallsend Boilers Ltd
PO Box 38
Calder Vale Rd
Wakefield
West Yorkshire WF1 5PF
Tel No: 0924 378211
Telex No: 55368
Mr A E Chadwick

Installation contractor
Bayliss Kenton Installations Ltd
Harwood Street
Blackburn
Lancashire BB1 3DW
Tel No: 0254 60011



Landfill gas shell boiler



Landfill gas firing the boiler

How landfill gas reduced conventional fuel consumption at Premier Brands

Premier Brands UK Ltd manufactures biscuits and other food products at its factory in Moreton, Merseyside. Steam is raised in a central boiler plant for space heating and process use. The base steam load is in excess of 1,250,000 therms/year.

Originally, the central boiler plant consisted of two duel-fuelled 'Maxecon' single furnace boilers rated at 18,000 and 30,000 lb/hour, a disused 8,000 lb/hour Towler water-tube boiler and a 40,000 lb/hour water-tube boiler which had recently suffered from superheater tube failure. The serviceable boilers are now retained as stand-by capacity.

Bidston Methane Ltd (BM) was formed to exploit the commercial potential of landfill gas extracted from a major waste disposal site. In 1984, Premier Brands (then Cadbury Typhoo Ltd) was approached by BM regarding the possibility of using landfill gas from a site some 2.75 km away. A survey of companies within an 8 km radius of the waste disposal site had identified Premier Brands as a suitable potential customer. A gas sale agreement was signed early in 1985.

A multi-fired Maxecon unit rated at 30,000 lb/hour with a working pressure of 150 psig was installed on the site of the previously scrapped water-tube boiler plant. The new unit was capable of firing on unrefined landfill gas and was fitted with fire-tubes and twin burners. Because this was the first scheme in the UK to fire unrefined landfill gas in a shell-type boiler, the project was supported by a grant from the Energy Efficiency Office's Energy Efficiency Demonstration Scheme (EEDS). As part of this support, the National Industrial Fuel Efficiency Service (NIFES) was contracted to monitor the contract. The landfill gas extraction project also received support under the Scheme and this is described in a separate Expanded Project Profile (216).

The new boiler was a conventional three-pass wetback economic unit as normally supplied for natural gas or fuel oil firing. Each furnace tube was fitted with a Hamworthy multi-fuel burner designed to burn heavy fuel oil, natural gas or landfill gas. In addition, the burners were capable of firing landfill and natural gas simultaneously. The Maxecon boiler was considered to be particularly well-suited to the project as the reversal chamber design enabled the user to operate on one furnace for indefinite periods.

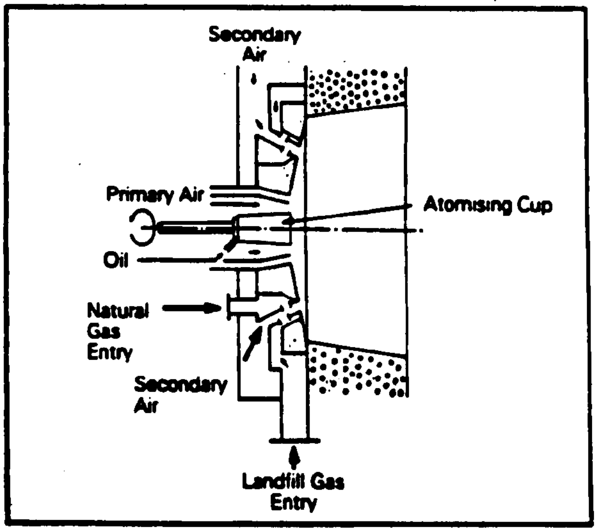
The boiler was arranged so that, during periods of low steam demand, the unit fired landfill gas on one firetube. The second burner was either off or was used as a 'top up' using natural gas. The two gases were fed into a gas train consisting of an upstream manual isolating valve fitted with a microswitch, two Class 1 automatic shut-off valves, a butterfly control valve and a downstream manual isolating valve fitted to the gas manifold inlet flange. High and low gas pressure switches were fitted with a third pressure switch for the valve proving system.

Monitoring of the project during the first year of operation showed that the shell boiler could be fired successfully with landfill gas. One difficulty encountered was with first-time ignition of landfill gas which was not always successful. On some occasions, it was necessary to intervene manually. Subsequent to the monitoring period this has been rectified.

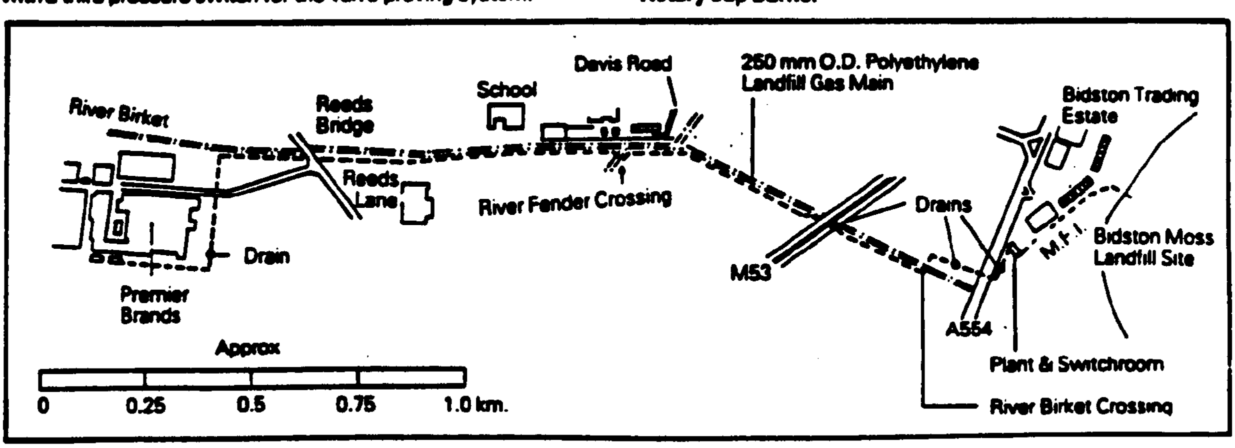
An oxygen-trim system was installed to overcome the problems associated with variations in the calorific value of the landfill gas and hence the excess air levels. The input of landfill gas was established at 33,000 ft^3/hour as a more consistent calorific value could be maintained at this rate. Excess air levels could then be set more accurately and any slight deviations could be handled by the oxygen-trim system.

During the first year of operation, plant stoppages were minimal and the overall availability of the gas was 98%. Over 60% of the consumer's natural gas consumption was replaced by landfill gas. The average thermal efficiency of the boiler plant fired with landfill gas was 77.1% compared with 78.4% for natural gas firing. The quality of the landfill gas was consistent and no noxious emissions were detected in the flue gases. There was no evidence of intensified boiler fireside corrosion during the monitoring period and fouling was not a problem.

Boiler replacement, which was one of the major expenditures for this project, is unlikely to be considered necessary in the majority of future applications of landfill gas. A typical site will only require burner replacement. Landfill gas therefore can provide an even more cost-effective option, with an associated reduced payback period of less than three years.



Rotary cup burner



Route of the landfill gas main

Conventional fuel and cost savings

During the 12-month monitoring period, 1,048,282 therms were supplied by landfill gas, 460,120 by natural gas and 205,312 by fuel oil. The price of natural gas fell during the period which in turn affected the price of the landfill gas. Fuel costs for the year were: natural gas £121,615; fuel oil £45,867. The accompanying table shows the cost of landfill gas for 10%, 15% and 20% discount rates (per therm).

To determine the financial savings made as a result of changing to landfill gas, it is necessary to take acount of the difference in the thermal efficiency of the boiler for natural and landfill gas and to calculate how much natural gas would have been required to give the same thermal output achieved with landfill gas firing. The landfill gas consumption of 1,048,282 therms was adjusted to give an equivalent natural gas input of 1,030,900 therms (4,124 tce) costing £252,811. Annual fuel cost savings for 10%, 15% and 20% discounts of landfill gas over the equivalent natural gas requirement are £21,464, £34,317 and £47,170 giving simple payback periods of 6.6, 4.1 and 3.0 years for the capital cost investment of £140,743.

A potential landfill gas user with a suitable existing boiler would only need to install a triple fuel burner and ancillary equipment which would probably cost about £50,000. Assuming the same levels of saving apply this results in payback periods of 2.3, 1.5 and 1.1 years respectively.

Replication

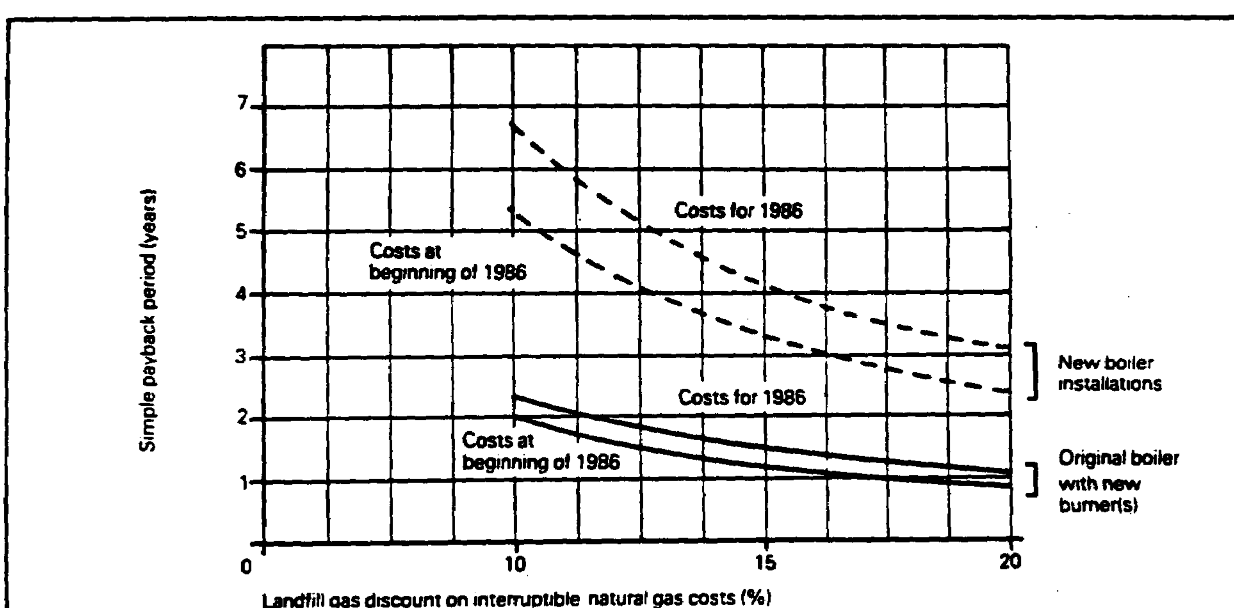
In the UK, approximately 25 M tonnes of biodegradable waste is deposited each year throughout 669 landfill sites. Of these approximately 300-350 contain sufficient quantities of refuse to produce commercial quantities of landfill gas. In the main, potential customers will be those large energy consumers within a reasonable distance of a suitable landfill site (say 10 km) and who have a continuous non-fluctuating base energy load in excess of or close to the anticipated site yield. However, this does not preclude the smaller, non-continuous energy user being able to make full use of landfill gas facilities. A landfill site is not restricted to a single user and there is no fundamental reason why it could not be used by a consortium. The application of landfill gas would be ideal for the chemicals, paper, textiles and food industries.

Multi-boiler plants and/or multi-burner boilers of the water-tube or fire-tube type would be most suited to burning landfill gas in commercial quantities. Most replicators would only require new burners for existing boilers and this would improve the economics of such schemes and reduce considerably the simple payback period.

Cost savings from using landfill gas

	Landfill gas discount 10%	15%	20%
Landfill gas	£231,347	£218,494	£205,641
Natural gas used instead of landfill gas*	£252,811	£252,811	£252,811
Savings	£ 21,464	£ 34,317	£ 47,170
Payback period (including boiler replacement)	6.6 years	4.1 years	3.0 years
Payback period (burner replacement only)	2.3 years	1.5 years	1.1 years

*corrected for boiler efficiency when firing landfill gas



Simple payback periods for landfill gas installations

Premier Brands UK Ltd

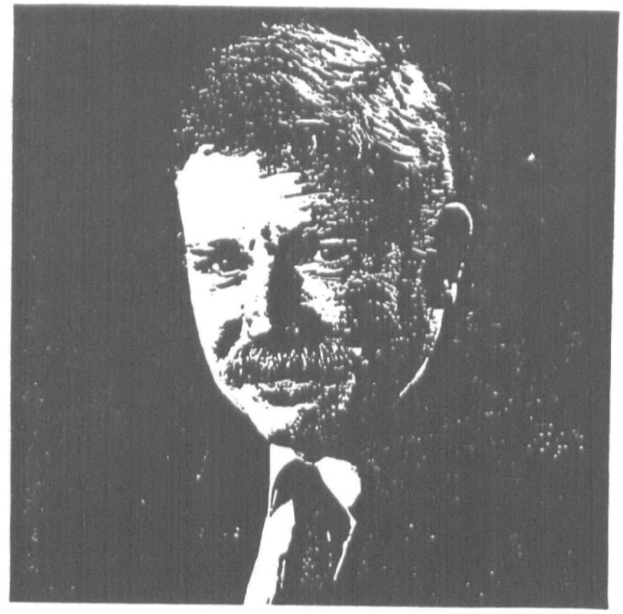
Premier Brands is a major UK manufacturer of biscuits and food products. It is therefore a large consumer of energy. The Merseyside factory at Moreton raises steam in a central boiler plant to provide space and process heating. The factory base steam load is in excess of 1.25 million therms/year.

Premier Brands' experience

During the early 1980s, site management faced a number of difficult decisions regarding steam generation. The demand for process steam had dropped dramatically as both confectionary manufacture and corrugated paper making had ceased on site. At the same time the generator and boilers were nearing the end of their useful lives. During this period the site operated on interruptible gas with heavy fuel oil as stand-by. The first attempt to reduce fuel costs involved the installation of a waste fired boiler to be fuelled by combustible waste generated on site. The project was unsuccessful and expensive. As a result, the Company was hesitant when approached by National Smokeless Fuels (NSF) with an outline proposal for the use of landfill gas from the nearby Bidston landfill site. However, it did offer the opportunity to complete the renewal of the boilers.

Price relativities between landfill gas, interruptible gas and heavy fuel oil were carefully monitored as the oil price varied. As a result, it can be seen that the reduction in fuel costs assumed for this project have, in fact materialised. Landfill gas provides a considerable proportion of our total fuel requirement. The technical risks thought to be associated with combustion and corrosion were imagined, rather than real. Unfortunately the installation does not allow for every permutation of landfill gas, interruptible gas and heavy fuel oil and there continues to be some difficulties experienced balancing landfill gas volume against calorific value.

Close cooperation with all parties concerned and the setting of tight deadlines for implementation have assisted with the project's overall success. The project has proved the acceptibility of landfill gas as a replacement fuel in shell boilers and achieved the cost reductions sought by the Company. Commitment to the project is enthusiastic and it has been the Company's most effective innovation in utilities.



Bob Mottram
(Site Director)

Further information

The work described here was carried out under the Energy Efficiency Demonstration Scheme.

The Energy Efficiency Office has replaced the Demonstration Scheme by the Best Practice programme which is aimed at advancing and disseminating impartial information to help improve energy efficiency. Results from the Demonstration Scheme will continue to be promoted. However, new projects can only be considered for support under the Best Practice programme.

More detailed information on this project is contained in the final report ED/191/217.

For copies of reports and further information on this or other projects, please contact the:

Energy Efficiency Enquiries Bureau
Energy Technology Support Unit (ETSU)
Building 156
Harwell Laboratory
Oxon OX11 0RA
Tel No: 0235 436747
Telex No: 83135
Fax No: 0235 432923

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Energy Efficiency Office
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DECEMBER 1986

Energy Efficiency Demonstration Scheme
Expanded Project Profile 153

Landfill Gas used as a Fuel in a Water Tube Boiler

A demonstration of conventional fuel savings in the paper board industry.

Potential users
Operators of water-tube boilers within 10km of appropriate landfill sites

Investment cost
£267,000

Payback period
Between 1 and 2 years

Savings achieved
£160,750/yr assuming a natural gas cost of 28p/therm and a landfill gas supply discount rate of 15%

Host company
Purfleet Board Mills
London Road
Purfleet
Essex RM16 1RD

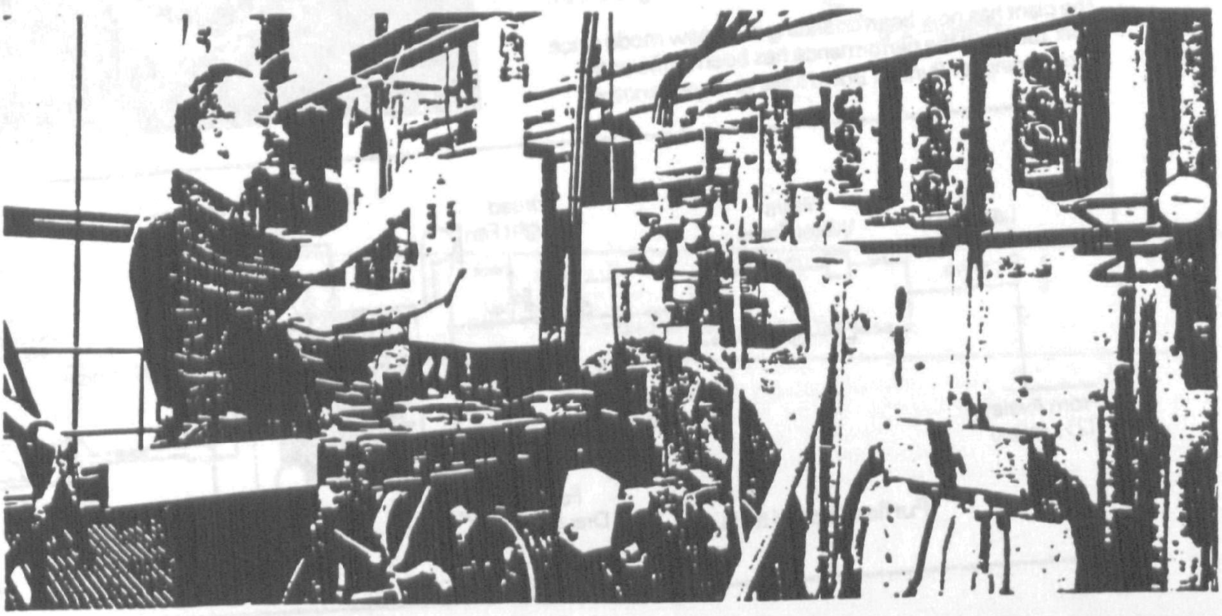
The aim of the project
Every year about 25 million tonnes of waste are buried in landfill sites in the UK. Organic material in the waste disposed of in this way decomposes under anaerobic* conditions and often produces a methane-rich gas. This gas can give rise to local environmental problems at some sites where the gas must be collected and flared. In some cases, the amount of gas produced is sufficient to be attractive commercially as an alternative fuel to nearby industry.
In this demonstration, landfill gas produced at a large landfill site at Aveley in Essex was piped to Purfleet Board Mills and used as the base fuel on a steam-raising boiler. The aim was to show that the gas could be used successfully in conjunction with either natural gas or heavy fuel oil and that it would be a safe and reliable source of energy. The consumer benefited from the lower price of landfill gas compared with natural gas. It was anticipated that landfill gas would contribute about 5,000,000 therms (20,000 tce) to the 14,000,000 therms (56,000 tce) consumed by the plant annually.

*in the absence of oxygen.

Monitoring contractor
NIFES Consulting Engineers
Charringtons House North
The Causeway, Bishops Stortford
Herts CM23 2ER
Tel No: 0279 58412
Mr A E Wright

Equipment manufacturer/installer
COMPUTER, CONTROLS AND COMMISSIONING
Babcock Bristol Ltd
218 Purley Way
Croydon
Surrey
Tel No: 01-686 0400
Mr J T Boswell

BURNERS AND BURNER MANAGEMENT
Babcock Power Ltd
Combustion Equipment Department
165 Great Dover Street
London SE1 4YB
Tel No: 01-407 8383
Mr D L McLachlan



13 see Potential users

How landfill gas reduced conventional fuel consumption at Purfleet Board Mills

The waste disposal site at Aveley in Essex covers 66 acres and receives large quantities of domestic refuse each year. In 1979 the Greater London Council (GLC), who owned the site, called in National Smokeless Fuels Ltd (NSF) to investigate the release of gas and to make recommendations for its treatment. It was determined that decaying refuse was generating a methane-rich gas in commercial quantities which could be useful as a fuel to local industry.

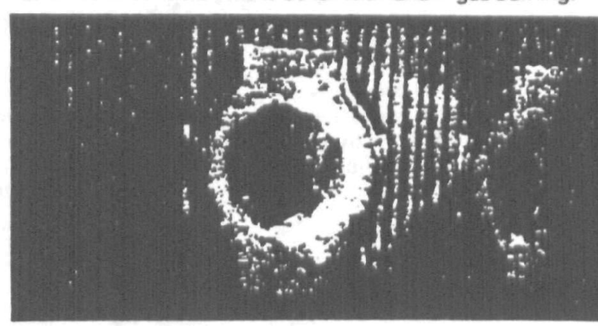
One of the large fuel users in the area, Purfleet Board Mills, agreed to buy landfill gas from Aveley and to use it to augment the conventional fuels used on a Babcock water tube boiler at its paper board mill. The boiler, which was rated at 200,000 lb/hour and fired by four natural-gas burners (with heavy fuel oil as standby), raised steam for electricity generation. Purfleet Board Mills decided to change to landfill gas burning on one of the burners. This involved installing a new 500m-long gas main from the Purfleet Board Mills boundary to the boiler plant, replacing one of the old burners by a new burner designed especially to burn landfill gas, and installing a computer control system to optimise combustion conditions and control general plant performance. All these changes were made as part of the Energy Efficiency Office's Energy Efficiency Demonstration Scheme. The laying of an underground pipeline from Aveley to Purfleet – a distance of some 2½ miles – was undertaken jointly by the GLC and NSF.

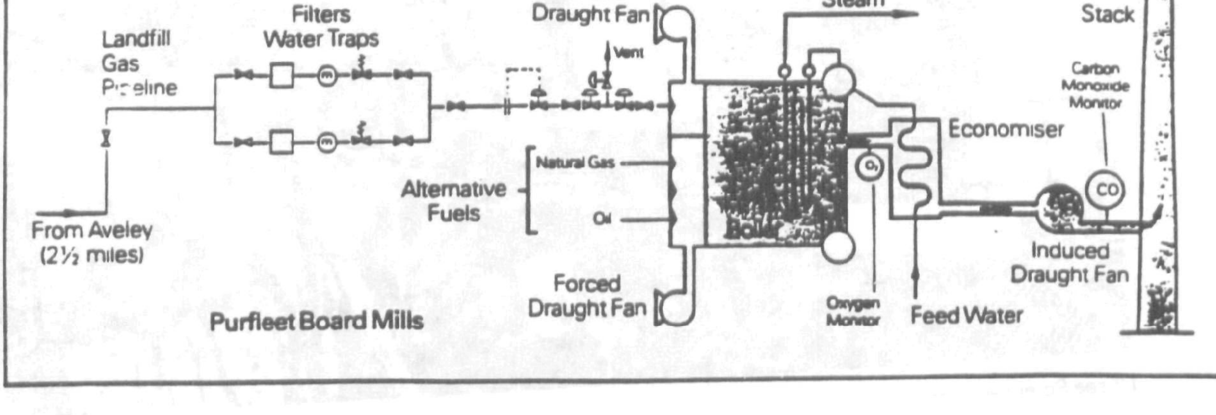
Special consideration had to be given to the nature of landfill gas in making the modifications. For example, the gas has a higher moisture content and is a mixture of methane and other, mainly inert, gases. It also has a lower calorific value than natural gas and this value tends to vary with the rate of use and the prevailing weather conditions at the landfill site. The cross-sectional area of the gas main was made twice as large to allow an increased rate of flow and so compensate for the lower calorific value of the gas; the discharge area of the holes in the burner were increased for the same reason. At the Aveley site, the gas was chilled prior to transport to remove the majority of the water while, at the consumer end of the pipeline, water traps and fine mesh filters were incorporated to reduce still further the water content and any entrained debris. The landfill gas was used as the base fuel on the boiler so that the other conventionally fuelled burners could compensate for any variations in supply. An automatic computer control system regulated fuel and air supplies to the three original burners according to steam demand.

The plant has now been operating in its new mode since April 1983 and the performance has been sufficiently encouraging for Purfleet Board Mills to modify another burner entirely at their own expense. Detailed monitoring was carried out as part of the demonstration from May 1983 to April 1984. This recorded the consumption of all fuels used, the thermal efficiency of the boiler and the calorific value of the landfill gas. In addition, tests were made to check whether corrosion within the boiler was increased by using the new fuel.

Results indicate that landfill gas has reduced the use of conventional fuels by slightly less than was expected, mainly because of a limited production rate at the well. Improvements have now been made which should increase the amount of gas available from the site and more than match the original requirements. Filters have had to be cleaned about every two months to remove a deposit of sludge and occasionally the gas supply has been shut down by the supplier for about an hour to allow maintenance to be carried out. This process usually results in a higher calorific value on return of supply. Regular checks on the calorific value of the gas have revealed that it tends to be above average after a holiday shut-down and below average during periods without any appreciable rainfall.

Burning landfill gas has presented few problems at the burner or in the boiler. By making it the base fuel, variations in supply and the occasional shut-down have been accommodated without any trouble. Initially, there was a problem of flame instability with the new burner which was caused by the gas discharge velocity being too high: because of the high inert content (CO_2), landfill gas has a much lower flame speed than natural gas. The holes in the burner were opened up further to give a lower velocity and no more problems have been experienced. The general appearance, shape and colour of the landfill gas flame is virtually identical to that produced by a natural gas burner. Tests have shown that there has been no increase in the incidence of corrosion in the boiler with landfill gas burning.





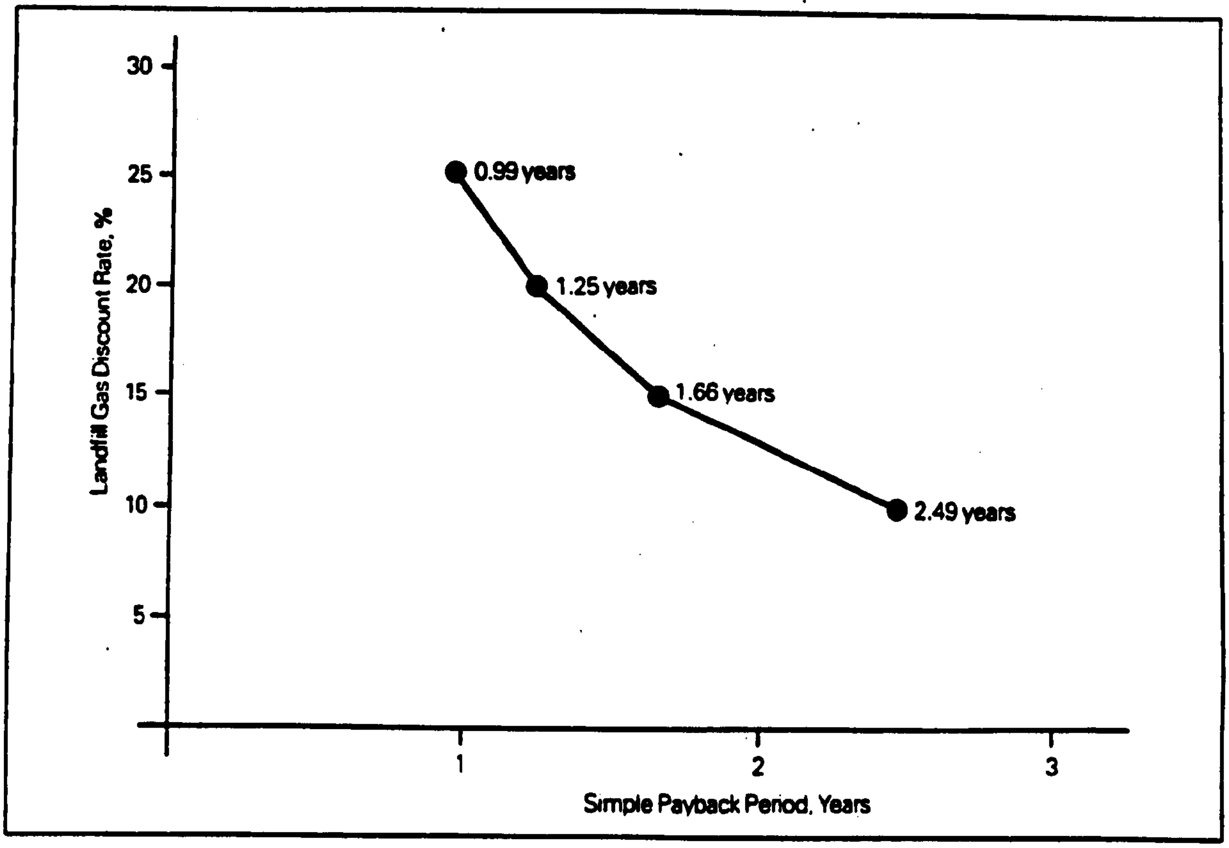
Conventional fuel and cost savings

Details of the consumption of fuels in the water tube boiler before and after modification are given in the accompanying table. Data for 1982 are taken from records kept by Purfleet Board Mills and refer to the period 1 January–31 December, while the 1983-84 figures come from the demonstration monitoring exercise between May and April. As can be seen, the average measured efficiency of the boiler dropped between these two periods. If the boiler had operated at its original efficiency throughout and the thermal output for 1983-84 had remained unchanged, the total thermal input for the period would have been 14,137,974 therms. Subtracting the contributions of natural gas and oil from this figure gives the consumption of landfill gas as 3,827,184 therms (15,310 tce) corrected for the difference in boiler efficiency.

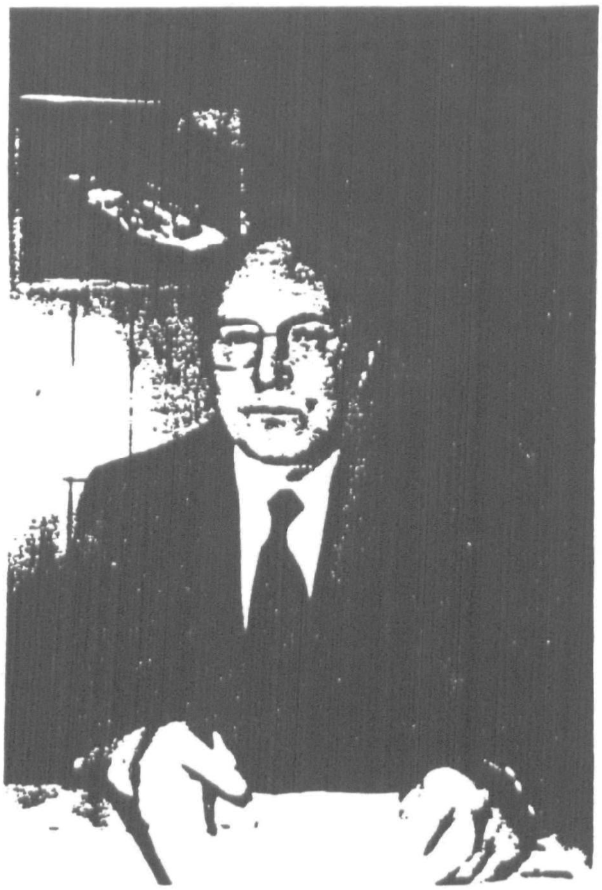
The installation at Purfleet Board Mills cost a total of £267,000. Financial savings in this demonstration resulted from the lower price paid for landfill gas compared with natural gas. Assuming that natural gas costs 28p/therm and that landfill gas is supplied at a 15% discount, financial savings of nearly £160,750 are made each year in an installation like this giving a simple payback period of just over one and a half years. The graph shows how the payback period is affected by different discount rates.

	Before modification 1982	After modification 1983-84
THERMAL INPUT:		
Natural gas, therms	12,943,703	10,217,227
Fuel oil, therms	691,346	93,563
Landfill gas, therms	–	4,099,251* 3,827,184**
Total, therms	13,635,049	14,410,041* 14,137,974**
BOILER EFFICIENCY	79.5%	78%
THERMAL OUTPUT, therms	10,844,185	11,244,170

*Recorded data
**Calculated at 79.5% efficiency



Purfleet Board Mills' experience



E Charles Smith

E Charles Smith
Chief Engineer

"In 1980/81, Purfleet Board Mills had been conducting a series of investigations into alternative energy sources: during these we learned from NSF – with whom we had previous association – of the possibility of a supply of LF Gas suitable for use as a fuel from a landfill site near the Purfleet Mill. Energy was becoming a major proportion of production costs, and had doubled in recent years. This possibility of using LF Gas as a boiler fuel was examined in some detail and its feasibility was confirmed.

There was in service at Purfleet a water-tube boiler with spare capacity which could be converted, and in 1982 authority was given to proceed with the project.

It was anticipated that flame stability could be a problem, and a low pressure burner was obtained to fit in place of one of the four existing burners so that the boiler could be dual fuel fired. Flue gas analysis and computer control was installed to provide precise regulation and maintain efficiency, although some loss of efficiency was anticipated due to the higher non-combustible content of LF Gas.

Problems with the installation were few, and first firing of LF Gas took place in April '83, one year after the project started.

LF Gas provides some 30% of total fuel requirements, the improved boiler control has compensated for losses due to LF Gas and there has been no appreciable loss of operating efficiency.

It was anticipated that some boiler gas-side corrosion could occur due to LF Gas, but monitoring tests have shown no measurable effect during the first year of operation.

There were initially a number of boiler shutdowns due to combustion disturbances; these were of short duration and had been anticipated and allowed for in the project assessment. The project is providing the anticipated return with 4M therms being supplied in the first year of operation.

The target of 5M therms was not achieved, but arrangements have been made to extend the use of LF Gas by converting a second burner.

The project has been successful. It would have been more convenient if this had been developed as part of a complete new installation, or used in a separate base load boiler, since the present installation seriously restricts any controlled trials to determine optimum conditions. There is every indication that this project will be developed and continue to make a major contribution to energy cost reduction."

Further Information

The work described here was carried out under the Energy Efficiency Demonstration Scheme.

The Energy Efficiency Office has replaced the Demonstration Scheme by the Best Practice programme which is aimed at advancing and disseminating impartial information to help improve energy efficiency. Results from the Demonstration Scheme will continue to be promoted. However, new projects can only be considered for support under the Best Practice programme.

More detailed information on this project is contained in the final report ED/060/153.

For copies of reports and further information on this or other projects, please contact the:

Energy Efficiency Enquiries Bureau
Energy Technology Support Unit (ETSU)
Building 156
Harwell Laboratory
Oxon OX11 0RA
Tel No: 0235 436747
Telex No: 83135
Fax No: 0235 432923

Information on participation in the Best Practice programme and on energy efficiency generally is also available from your Regional Energy Efficiency Office.

The Economics of Landfill Gas Projects in the United States[1]

By G.R. Jansen, Vice President, Laidlaw Gas Recovery Systems

This paper is based on the experience of Laidlaw Gas Recovery Systems in developing, owning and operating landfill gas projects since the early 1980's.

Although GRS is currently operating 12 landfill gas projects, only one of these, is a medium BTU project. This project is located in Sacramento, California and sends over 1 MM cubic ft./day to a Biomass plant burning almond shells. The rest of the GRS projects are landfill gas to electrical energy projects ranging in size from 650 kw to 20,000 kw. The projects are located mostly in Northern and Southern California.

The information in this paper including the capital costs, pricing of electrical energy, and operating costs comes from the GRS electrical projects. Although the overall economic analysis contained in this paper is for a small electrical generating project, much of the same type of analysis and evaluation of the same factors would have to be carried out for a medium or a high BTU landfill gas project.

Medium BTU

The GRS Sacramento plant is a medium BTU project which began operation in 1991 at a level of a little over 1.0 million cubic feet of landfill gas per day. The landfill at Sacramento has continued to be filled during the operation of the GRS facility which will eventually allow more landfill gas to be generated. The capacity of the plant is estimated to be between 1 and 2 million cubic feet per day with some minor modification.

The gas is collected, filtered, compressed to about 6 psi and then piped to the Generating Plant where it is used as a fuel in a steam power plant supplementing natural gas.

Electrical

GRS began generating electrical energy in Northern California in 1983 with the 1 MW plant. By 1991 (figure 1), approximately 44.5 MW were on line selling power to the various utilities. The plant locations, capacities and amount of gas processed per day are:

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[1] This paper was presented in Melbourne, Australia, on February 27, 1992

Location	Capacity MW	Gas Processed MM Cub. Ft. per day
Menlo Park, CA	2.0	1.5
Guadalupe, CA	2.5	1.9
Newby Island, CA	5.0	3.8
American Canyon, CA	1.5	1.0
Mountain View, CA	3.5	2.5
Coyote Canyon, Orange Co., CA	20.0	14.0
Sycamore, San Diego, CA	1.5	1.0
San Marcos, San Diego, CA	1.5	1.0
Orange, New York	3.0	2.0
Kapaa, Hawaii	3.0	2.0
Santa Cruz, CA	1.0	.7
Total	44.5	31.4

GRS generates electricity from landfill gas using many different types of generating equipment ranging from small multi unit reciprocating engines, to gas turbines, and ultimately a steam turbine. (Figure 2) In general, the technology was tailored to each particular application.

The first group of projects tended to use small 500 kw naturally aspirated internal combustion engines. Since there were no similar projects on the west coast when we began operating in early 1982, engines were selected based on their simplicity and operating histories in the closest similar environment. These were the Cooper Superior straight 8's which had an excellent operating history in remote oil pumping stations, drilling platforms, and many applications using fuels with heat rates less than natural gas. The operating philosophy was than many small units would be much more reliable in terms of maintaining productivity, than one or two larger ones. Also, our first landfill gas project at Menlo Park had been tested by one of our competitors and found to not contain enough gas for economic production. Our concept was that if the gas supply decreased over time we could reduce the number of units to correspond to the gas supply.

Finally, as our experience in estimating the volume of landfill gas improved, we began to take greater risks in the number and type of prime movers. The air quality and other environmental considerations also began to play a larger and larger part in the selection of equipment. Our largest project, the 20 MW steam turbine in Orange County, California was built in the most restrictive air quality basin in the U.S., and subject to all of the rules and regulations of the South Coast Air Quality Management District.

The project was originally planned as 5 Solar Centaur gas turbines generating approximately 15 MW. Air quality permitting quickly rejected this technology as being too high in NOx emissions. The resulting boiler and steam turbine was several magnitudes cleaner with NOx emissions in the 15 to 20 parts per million.

Figure 1

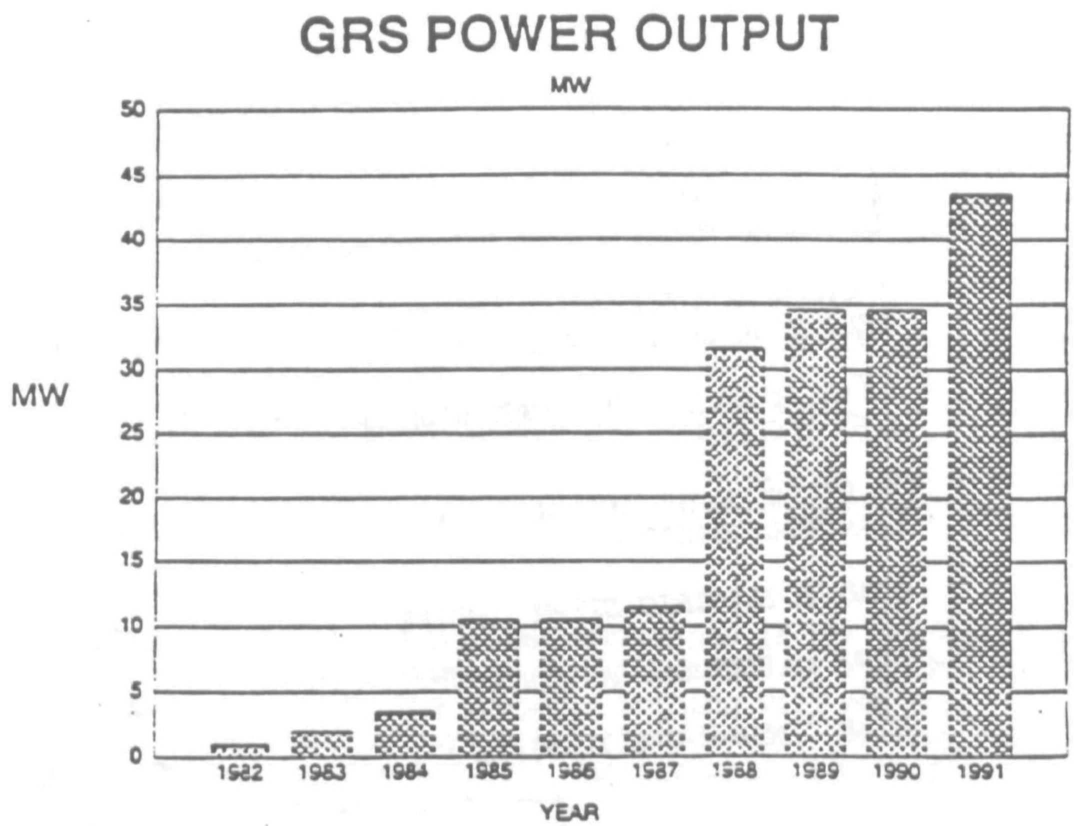

GRS POWER OUTPUT
MW
MW
50
45
40
35
30
25
20
15
10
5
0
1982
1983
1984
1985
1986
1987
1988
1989
1990
1991
YEAR

FIGURE 2

GRS

TECHNOLOGIES USED

NUMBER	TYPE	OUTPUT
11	8 CYLINDER NATURALLY ASPIRATED COOPER SUPERIOR RECIPROCATING ENGINES	500 KW EACH
2	8 CYLINDER TURBOCHARGED COOPER SUPERIOR LEAN BURN RECIPROCATING ENGINES	750 KW EACH
4	12 CYLINDER TURBOCHARGED WAUKESHA LEAN BURN ENGINES	1100 KW EACH
2	16 CYLINDER TURBOCHARGED COOPER SUPERIOR LEAN BURN ENGINES	1750 KW EACH
1	GENERAL ELECTRIC STEAM TURBINE	20 MW
5	SOLAR SATURN GAS TURBINES	1000 KW EACH
2	SOLAR CENTAUR GAS TURBINES	3000 KW EACH

Factors which we consider in developing a project

- Landfill Characteristics
- Markets
- Technology
- Environmental
- Legal

1. Landfill Characteristics

Figure 3 lists the factors that should be considered in deciding whether or not a landfill is worth developing. A landfill gas study is always useful especially during later financing by banks and other institutions. The issue of whether there is gas in the landfill and the credibility of the engineer making the estimate becomes a very major factor in determining how or if the project is financed. We have had limited success in predicting gas and have tended to become more and more conservative.

A beginning and relatively safe rule of thumb is to use the gas generating factor of 0.1 cubic feet of gas per year from each pound of refuse placed in the landfill. This only applies to landfills that contain household refuse and are somewhat wet. Moisture content of the refuse does play some part in the volume of gas generated, although it is unclear at this point just how important this is in the long run.

2. Markets

This factor probably more than any other determines if the project will go forward. If there are no customers for the medium or high BTU fuel, or the electricity produced by the project, nothing will happen. Further, not only must there by buyers for the product, but they must be prepared to take as much as the landfill can produce. Purchase contracts must be "take or pay" contracts.

The contract negotiation for the landfill gas or electricity produced should be carried out immediately following the gas test of the landfill. At this point, electrical generating capacity in KW, or volume of cubic feet per day can be estimated. Curtailment provisions, base energy rates, and escalators should be worked out since these will be required by the financiers. Signed contracts are essential. Verbal agreements are great, but signed contracts are bankable. Use of a good energy contract attorney is highly recommended. There is nothing worse than trying to renegotiate terms and conditions the second and third times. This creates time delays and more importantly, developer credibility suffers.

FIGURE 3

LANDFILL CHARACTERISTICS

MINIMUM GAS REQUIREMENTS FOR RECOVERY PROJECT

- In place tonnage: 2 million plus
- Depth of Refuse: 35 feet or more
- Type of Refuse
- Acreage: 35 plus acres
- Continued landfill operation for several years
- Seal/cap material on landfill
- If the landfill is closed, how long did it operate and when was it closed.

Electrical projects in California and a number of other states have been made much easier by the adoption of so called "Standard Offers" which require utilities to purchase power from small cogenerators. Not only are the terms and conditions set by the Public Utility Commission, (PUC), but in some cases the prices of electrical energy as well. The contracts are usually "take or pay" and are relatively easy to understand by the developer and the financier.

To foster the growth of cogenerators, in the mid 80's utilities offered so called firm price offers or contracts. This fixed the price the developer will be paid for this energy for a relatively long period of time (10 years) and took away one of the major uncertainties in financing landfill gas projects. In some contracts the developer has the option of selecting either a fixed price per kwhr or a floating price per kwhr contract, or a combination of both. In California, this type of contract was called Standard Offer No. 4. The original S.O. #4's created a gold rush of "blue suede shoe" developers. By the time the PUC's/utilities realized their mistake, over 10,000 MW were signed up.

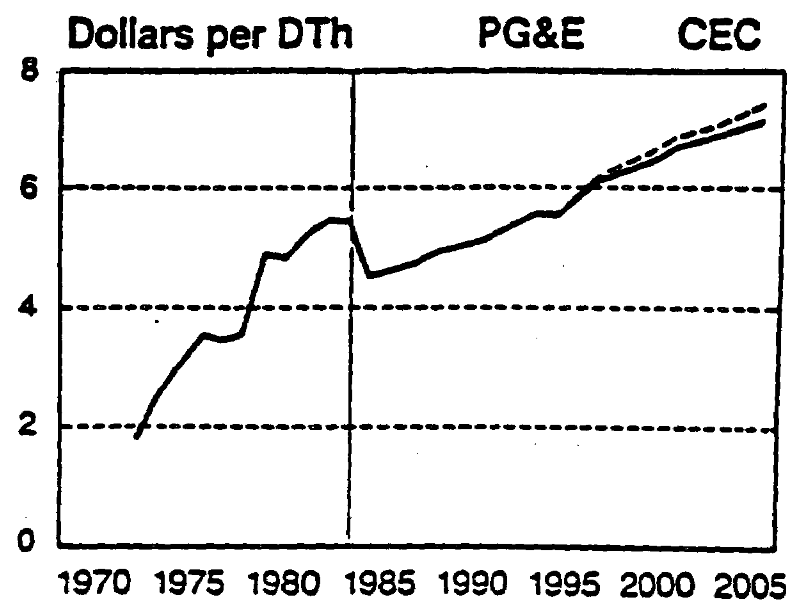
Figure 4 shows the historic growth in both natural gas rates and electrical rates since the 1970's. Although the figure shows the retail price of energy it does serve to illustrate that in the case of electrical energy, the price is projected to remain relatively level. All of the statistics are from PG&E which is one of the largest utilities in the U.S.

The price of energy paid to the landfill gas developer is not however, the retail price of energy. The cogenerator price, the so called "avoided cost" is shown in figure 5. Simply, the avoided cost is the cost the utility "avoids" by buying power from a cogenerator rather than building its own facilities. It is defined as the product of the utility's incremental heat rate and the marginal cost of the utility's fuel.

This marginal fuel in the case of PG&E is either natural gas or oil or a combination of both. Figure 5 also shows the fluctuations in the avoided cost that have taken place since 1980. Not only does the falling price of natural gas or world oil pricing effect the avoided cost but also the utility's own heat rate. When PG&E started up their nuclear powered generator (Diablo 1), in 1985, there was a significant drop in the avoided cost primarily due to the decrease in the heat rate. In effect, PG&E was able to shut down some of the more inefficient power plants in their system.

Figure 4

Gas Rates (Real)



Electric Rates (Real)

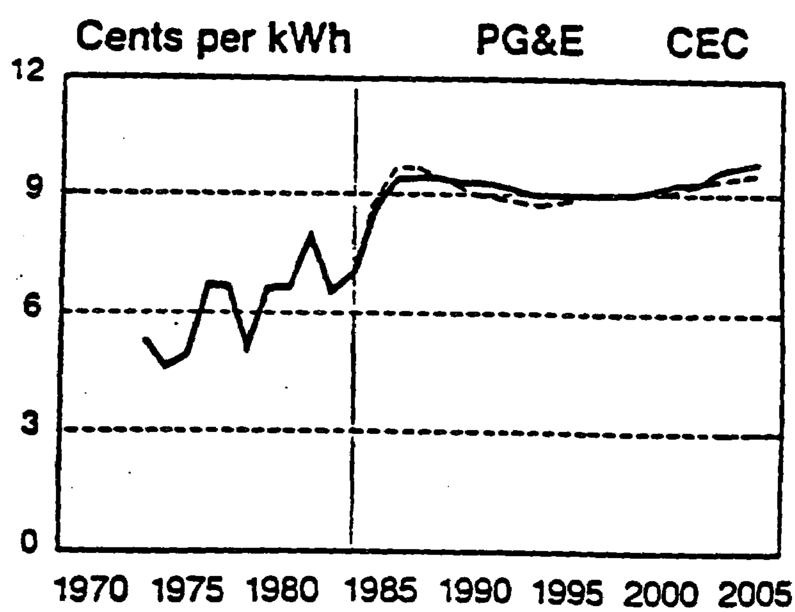
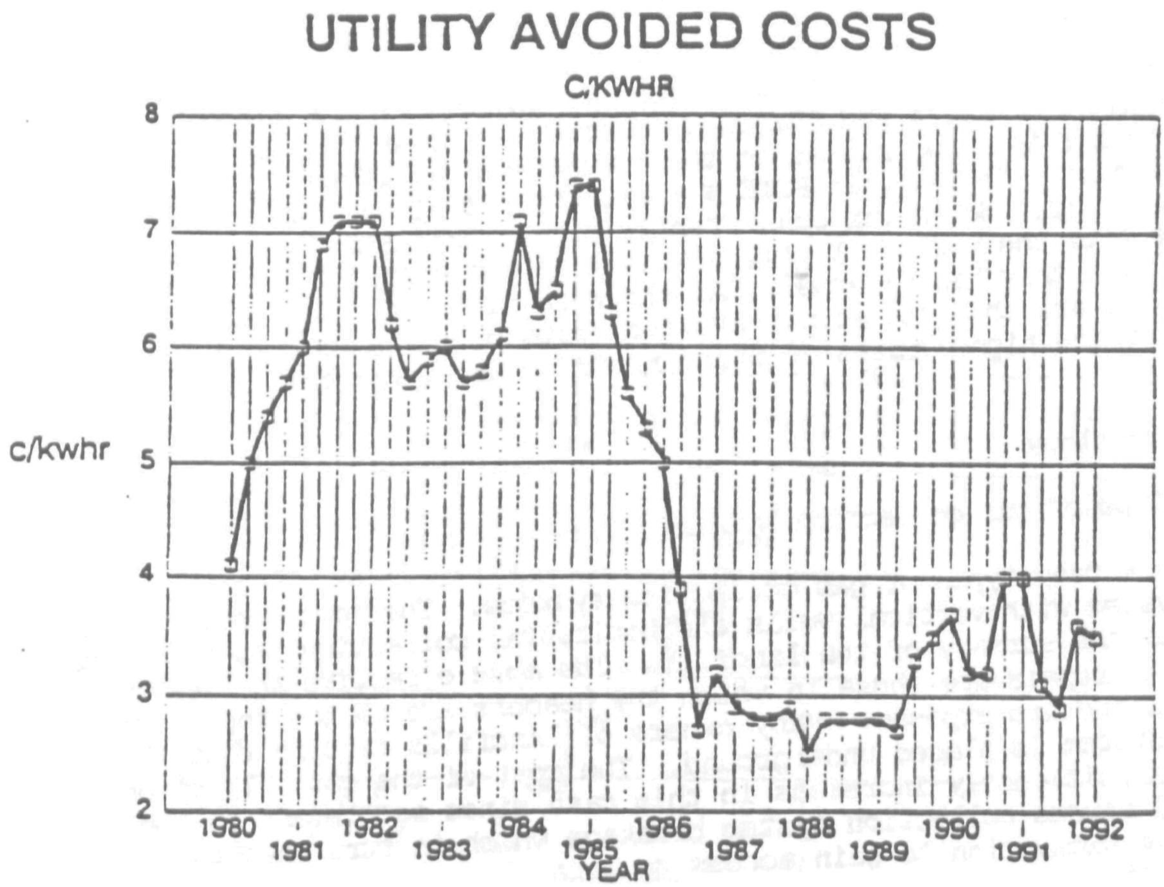


Figure 5


UTILITY AVOIDED COSTS
C/KWHR
c/kwhr
8
7
6
5
4
3
2
1980
1981
1982
1983
1984
1985
1986
1987
1988
1989
1990
1991
1992
YEAR

In addition to paying a price for the generated kwhrs, some utilities also pay a capacity payment. Very simply, this is a payment (based on a generating turbine), paid to a cogenerator for having a reliable power plant capable of delivering power at least 80% of the time during the utilities' peak months. The capacity payment can be levelized depending on the term of the contract and depending on how long the developer thinks landfill gas in his project will last. Rates varied but were generally between \$100 to \$200/kwyr.

In some States, the capacity payment is simply added into the price of electrical energy and is paid on a cent per kwhr basis. In California, the capacity impact is approximately 1.5 to 1.8 cents per kwhr.

By the late 1980's even this went away as utilities decided they had too much capacity. Figure 6 is a comparison in between the fixed price of Standard Offer No. 4 and Standard Offer No. 2 in which there is no fixed pricing but is based rather on the actual avoided costs that the utility experiences. In 1985, in PG&E's area, the actual avoided cost of Standard Offer No. 2 was consistently higher than Standard Offer No. 4. By the time the world oil glut was felt in the marginal fuel pricing in early 1986 this had reversed. As shown in figure 6, the current estimates are that the actual avoided costs of Standard Offer No. 2 will be below the higher rates of Standard Offer No. 4 for the foreseeable future.

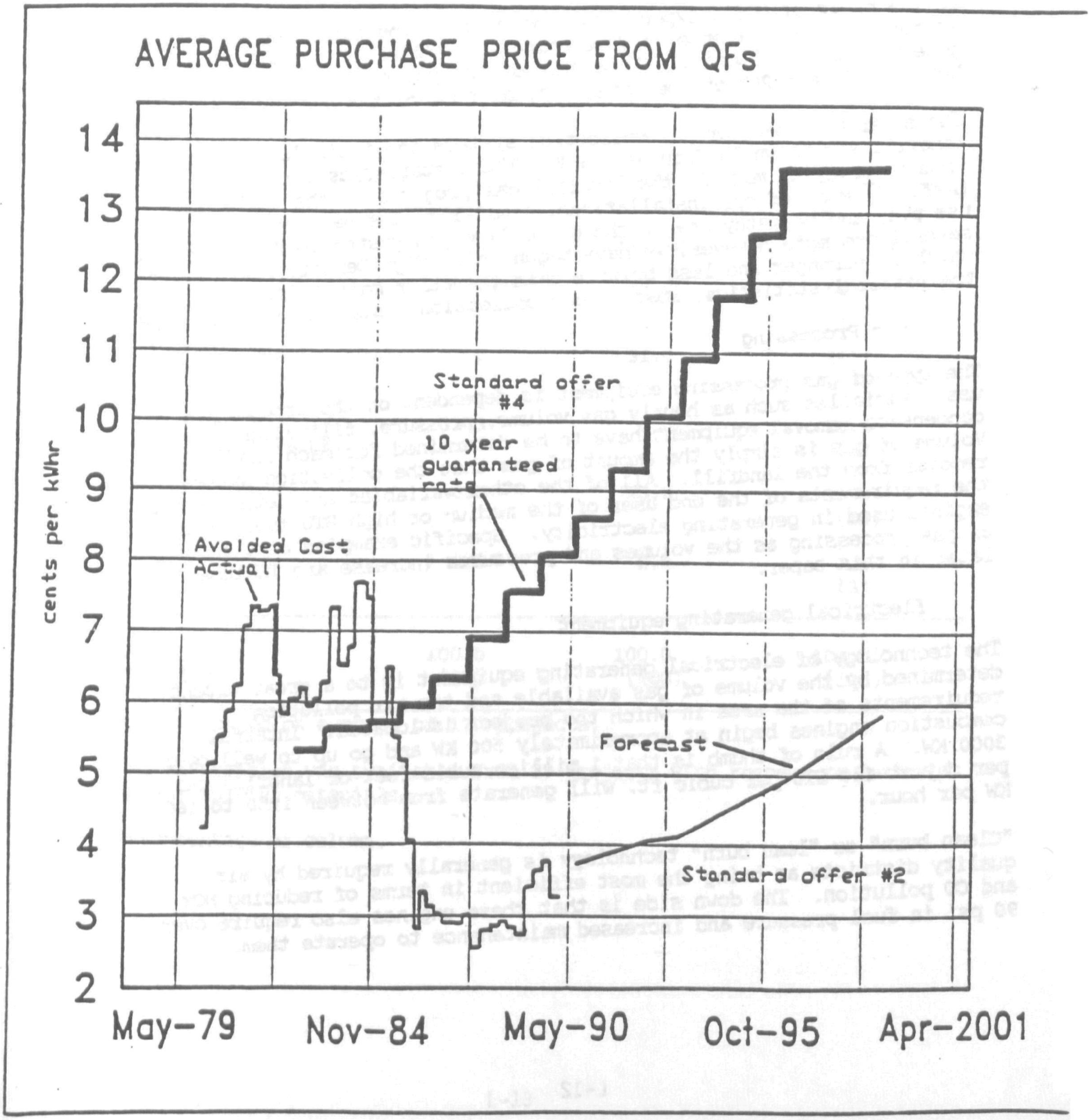
3. Technology

Type of gas collection system

There are many types of gas collection systems. The most conventional is a system with vertical wells and horizontal collection headers spread out over the surface of the landfill. The most effective and least costly to repair are those in which the headers are on the top of the landfill and are exposed. Many owners of landfills require that the header system is placed underground. The cost of the gas collection system significantly increases in this case since settlement in the landfill causes collection system breakage which in turn results in expensive excavation to gain access to laterals. In some cases it's cheaper to just replace parts of the system altogether.

Trench collection systems have been shown to be effective in certain instances as have pipe systems installed in refuse while it is placed in the landfill. In many cases where we have tried horizontal systems, breakages of the lines occurred and the lines were ultimately abandoned. The quality and quantity of the gas generated using these systems was also less than was observed with vertical systems.

Figure 6


AVERAGE PURCHASE PRICE FROM QFs
14
13
12
11
10
9
8
7
6
5
4
3
2
cents per kWhr
Standard offer #4
10 year guaranteed rate
Avoided Cost Actual
Forecast
Standard offer #2
May-79
Nov-84
May-90
Oct-95
Apr-2001

If the landfill is open, additional problems have to be resolved in designing gas collection systems that are compatible with the on going refuse filling operation. How expensive this is ultimately is a function of the attitude of the landfill operator. Lateral collectors often cross roads which requires culverts and other types of reinforcing.

On the basis of GRS's experience, the cost of the gas collecting system is not the major expense in developing a landfill gas project. In general, we have found that the cost of the collection system varies between 10% and 20% of the total capital cost of the project.

The materials used for gas collection systems and their location on the landfill are shown in Figures 7 & 8. These statistics were developed from a survey of most of the landfill gas projects in the whole U.S. (Ref. 1) Most of our installations, similar to the national statistics use pvc, and polyethylene in the gas collection systems. Over the last several projects however, we have begun using High Density Polyethylene which is stronger and less brittle than the other materials. Similar to the national statistics, most of our collection systems are underground.

Gas Processing

The type of gas processing equipment is dependent on the product end use. Variables such as hourly gas volume, pressure, filtration, condensate removal equipment have to be determined for each landfill. Volume of gas is simply the amount of gas that the collection system removes from the landfill. All of the other variables are determined by the requirements of the end user of the medium or high BTU fuel or the engines used in generating electricity. Specific examples of the cost of gas processing as the volumes and pressures increase are included later in this paper.

Electrical generating equipment

The technology of electrical generating equipment is to a great extent determined by the volume of gas available and the air pollution requirements of the area in which the project is located. Internal combustion engines begin at approximately 500 KW and go up to well over 3000 KW. A rule of thumb is that 1 million cubic feet of landfill gas per day at 450 BTU per cubic ft. will generate from between 1250 to 1600 KW per hour.

"Clean burn" or "lean burn" technology is generally required by air quality districts as being the most efficient in terms of reducing NOx and CO pollution. The down side is that these engines also require over 90 psi in fuel pressure and increased maintenance to operate them.

Figure 7

MATERIALS USED IN LATERAL/HEADER PIPES*

Type of Material	Status: Planned	Existing	All Facilities
Polyethylene (PE)	38.9%**	48.0%	46.6% (55)
Polyvinyl Chloride (PVC)	22.2	31.0	29.7 (35)
High Density Polyethylene (HDPE)	33.3	6.0	10.2 (12)
PE and PVC	0.0	13.0	11.0 (13)
Other Material	9.6	2.0	2.5 (3)
Total % (Total #)	100.0 (18)	100.0 (100)	100.0 (118)

*Survey based on average of 170 projects.

No information was available from 39 projects with respect to lateral/header piping materials.

**Percentage of column.

Figure 8

LOCATION OF LATERAL/HEADER PIPES*

	Status		
Type of Material	Planned	Existing	All Facilities
Above Ground	11.8%**	23.5%	21.9% (26)
Below Ground	82.4	66.7	68.9 (82)
Above and Below Ground	5.9	9.8	9.2 (11)
Total %	100.0 (17)	100.0 (102)	100.0 (119)

*Survey based on a summary of 170 projects.

No information was available from 38 projects with respect to location of lateral/header pipes.

**Percentage of column

Gas turbines tend to be smaller than the comparable sized internal combustion reciprocating engines and have better emission characteristics. A negative is that the gas inlet pressure requirement can be well in excess of 100 psi. Consequently, turbine installation have high parasitic loads. Historic operating statistics indicate that while the turbines are trouble free, the gas processing and filtering equipment is the high maintenance item.

Interconnect

The electrical interconnection between the utility and the project can be quite expensive especially if the utility has to make modifications to its substation. As much of the interconnect should be built by the landfill gas developer as possible. This saves time and is generally much less expensive than if the utility does it. Lead times for California utilities tend to be well over 6 months from beginning planning to final construction. This should be included in the development schedule.

4. Environmental concerns

The environmental concerns for project development of a landfill gas project are listed in figure 9. Project development begins with land use permitting, air quality permits and water quality permits. Each of these need specific information on the project such as the number and type of engines proposed, type of gas processing, emission levels of all pollutants and volumes of condensate generated. Detailed engineering is not required until after all of these permits are obtained.

Once the above three types of permits are received, detailed plans and specifications can be prepared and submitted to the local building departments for review. Although this can be time consuming, permits are generally given for projects that are considered environmentally sound. If the permit and detailed engineering phases are done sequentially, the project can take well over a year for these two phases alone prior to construction. GRS has generally submitted all of the permit applications and at the same time has continued with detailed engineering. The ideal is to receive the water quality and emission permits at the same time as the building permit. A risk in trying to carry out several functions concurrently is that detailed engineering may have to be redone several times to comply with the requirements of the local jurisdictions reviewing the submittals.

Figure 9

ENVIRONMENTAL CONCERNS
FOR PROJECT DEVELOPMENT

- LAND USE PERMIT
  - Compatibility with land use on and around landfill
  - Noise
  - Fire Protection
  - Flooding/Drainage
  - Foundations
  - Other Environmental Impacts
- AIR QUALITY
  - Landfill Emissions
  - Migration Control
  - Emissions of NOx, CO from LFG Project itself
- WATER QUALITY
  - Disposal of Condensate
- BUILDING PERMITS
  - Foundations
  - Building Type, Appearance
  - Noise Insulation
  - Fire Protection
  - Security
  - Landscaping

5. Legal/commercial concerns

A list of these factors is shown in figure 10. The gas lease agreements and power purchase agreements will determine how easy the project will be to finance later on. An important issue is the assignability of the contracts. If limited partnerships are set up, the contracts must make provisions to allow a new legal entity to step in and take over all of the obligations of the primary developer. Utilities are generally nervous when this happens and require in some instances recourse to the original developer in the event that the partnership has a problem. This is especially true in levelized capacity contracts which include penalties for non performance.

Another issue includes the term of the contract. The gas lease and the power purchase agreement should have the same time period.

As regulations relative to the migration of landfill gas become more and more stringent, the liability and who assumes it can become a major negotiating point. If possible, landfill gas developers should attempt to mitigate against gas migration and the emissions from the landfill but the ultimate responsibility should remain with the owner of the landfill. Who ultimately has the responsibility will affect the financing of projects. Long term environmental impairment insurance is either very expensive or not available. Bankers tend to view this negatively.

The tax issues, such as who takes the Production Tax Credits (PTC), can affect the financial attractiveness of a project. The internal rate of return of a project which takes these tax credits can be significantly increased. For private landfills, the Production Tax Credits could be used in lieu of royalty and can be worth much more than the royalty income. Whether these credits will continue past the year 2000 remains to be seen as the U.S. Congress reviews the whole question. Currently, a landfill generating 1 million cubic ft. of landfill gas per day would yield over $150,000 per year in Production Tax Credits.

The issue of PTC's has had a significant impact on the development of landfill gas projects especially by those company's that had an appropriate tax appetite. In fact, projects that had normally negative cash flows could become profitable primarily due to the PTC's.

Capital Costs

GRS's historical cost of electrical generating plants while originally decreasing started to increase from 1985 on steadily decreasing per installed KW as shown in Figure 11. In 1983, when GRS's first electrical generating project was built at Menlo Park, California, the total cost of the project was a little over $1.25 million per MW output. This included the gas processing, filtration equipment, gas collection system (50+ wells), electrical interconnect, all internal combustion engines, generators, all switchgear and building to house all of the equipment.

Figure 10

LEGAL/COMMERCIAL CONCERNS FOR PROJECT DEVELOPMENT

- GAS LEASE AGREEMENTS
    - Term of Agreement
    - Royalties
    - Assignability
    - Environmental Liabilities
- POWER PURCHASE AGREEMENTS
    - Following Interconnect Priority Procedures
    - Curtailment Provisions
    - Pricing
    - Penalties - Long Term
    - Assignability

TAX ISSUES

- PRODUCTION TAX CREDITS

In 1984, when two additional projects were built, at Guadalupe, Santa Clara County, Ca and Newby Island, San Jose, Ca, the total installed cost was over $1.15 million per KW output. This cost was further reduced to $1.07 million per MW in 1985 when two more plants were put on line at American Canyon, Napa, Ca, and Mountain View, Ca.

In 1988, the 20 MW Coyote Canyon steam generating plant cost $1.3 million/MW. Again, this includes a fully operational power plant with all buildings and landfill gas collection system as well as all of the changes that occurred due to plant modifications resulting from air quality issues.

Gas Processing costs

Figures 12 and 13 show our experience in gas processing. The primary determinant in gas processing equipment is the volume of gas that is processed per day. A secondary variable is the processing pressure. A plant handling 5 million cubic feet of landfill gas per day at 70 psi is 5 times as expensive as one handling 1 to 1.5 million cubic feet per day.

Operating Costs

Figure 14 shows our operation cost experience over the last 8 years. When we began operations with new equipment in 1982, operating costs were a little less than 2 c/kwhr; last year (1991), they had increased to about 2.7 c/kwhr, which represents about a 4% per year compounded growth rate, or a growth rate consistent with inflation. These figures include all of the reciprocating projects. Additionally, the overall operating costs have been increasing steadily over the last 4 years or so following a buildup of a maintenance organization capable of carrying out more and more of the engine maintenance and operations functions. Additionally, the 2.7 c/kwhr includes all of the field maintenance, operations and monitoring required to operate the projects.

We have found that there is no such thing as an unmanned plant. The only way that 80 to 85% capacity factors can be maintained is by having a plant operator present at least 8 hours per day. (An 80% capacity factor as we define it, means that the plant is producing at its rated output during 80% of the total number of hours in a year.) The function of the operator is to assist in general maintenance of the engines and to repair the gas collection system.

The steam generating project has not been included in these statistics since it is manned 24 hours per day, 7 days per week and uses a different technology. Its operating costs have tended to be about 15% less than the small reciprocating plants. Although GRS has 5 gas turbine projects, the total operating time has not been long enough to establish any kind of history. Thus far however, we believe that the gas turbine plant operating costs will be comparable to the reciprocating projects.

Figure 11

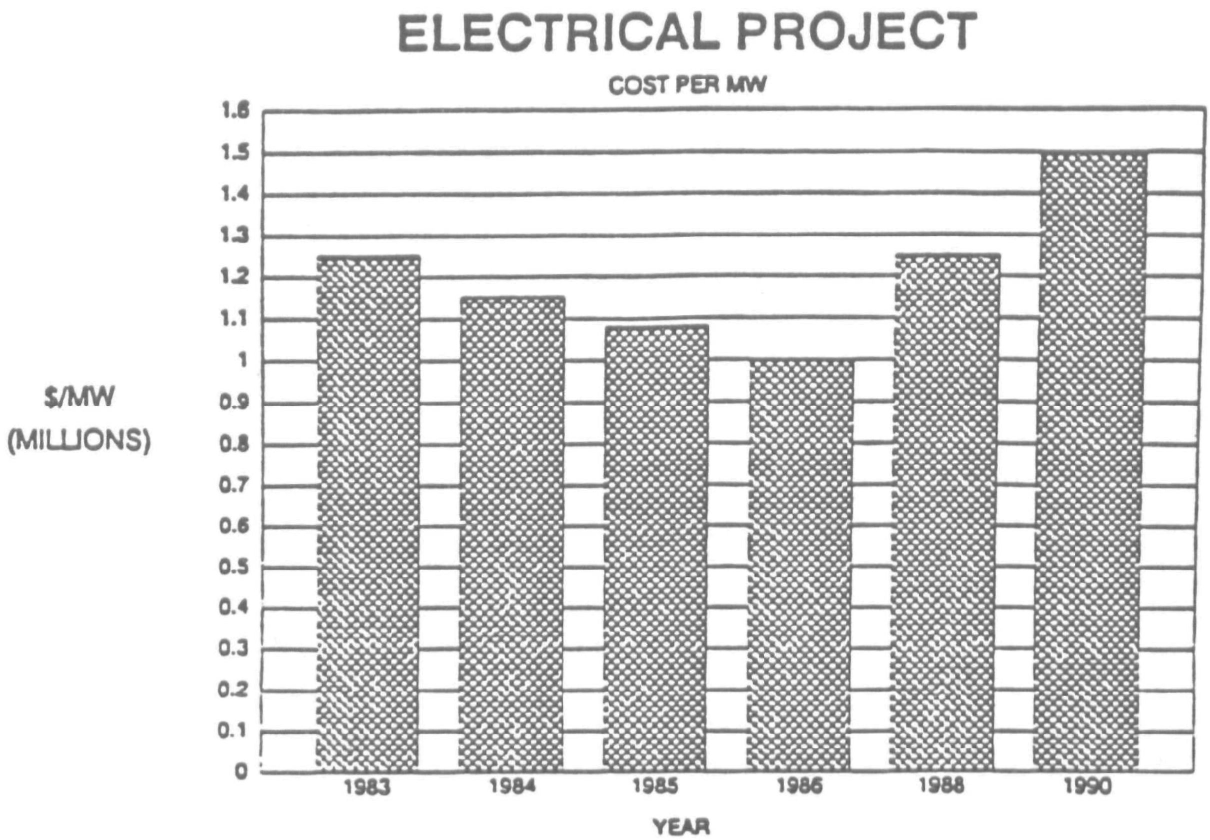

ELECTRICAL PROJECT
COST PER MW
$/MW
(MILLIONS)
1.6
1.5
1.4
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
1983
1984
1985
1986
1988
1990
YEAR

Figure 12

GAS PROCESSING COSTS
VERSUS PRESSURE, VOLUME OF GAS

Project	Dollar Cost (1,000's)	Pressure (psi)	MM Cu ft/day Gas Vol.
Bradley*	1,000,000	70	5.0
Menlo Park	25,000	2	1.4
Guadalupe	150,000	25	1.1
Newby Island I	80,000	8	1.4
American Canyon	222,000	90	1.0
Mountain View	372,000	90	2.3
Newby Island II	300,000	45	2.0
Medium BTU			
Rotary Lobe	220,000	14	1.89
Reciprocating Comp.	250,000	20	1.89

*Built by GRS but sold in 1990.

Figure 13

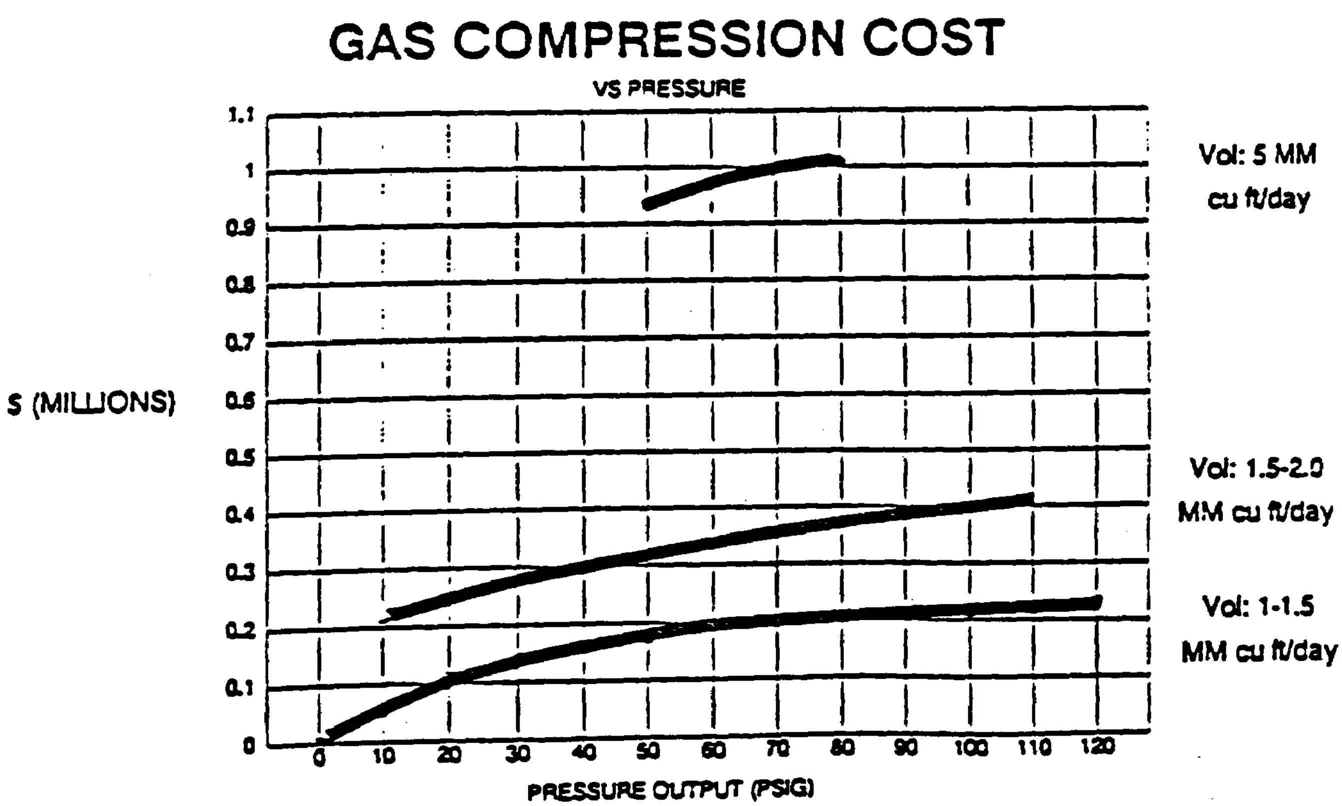
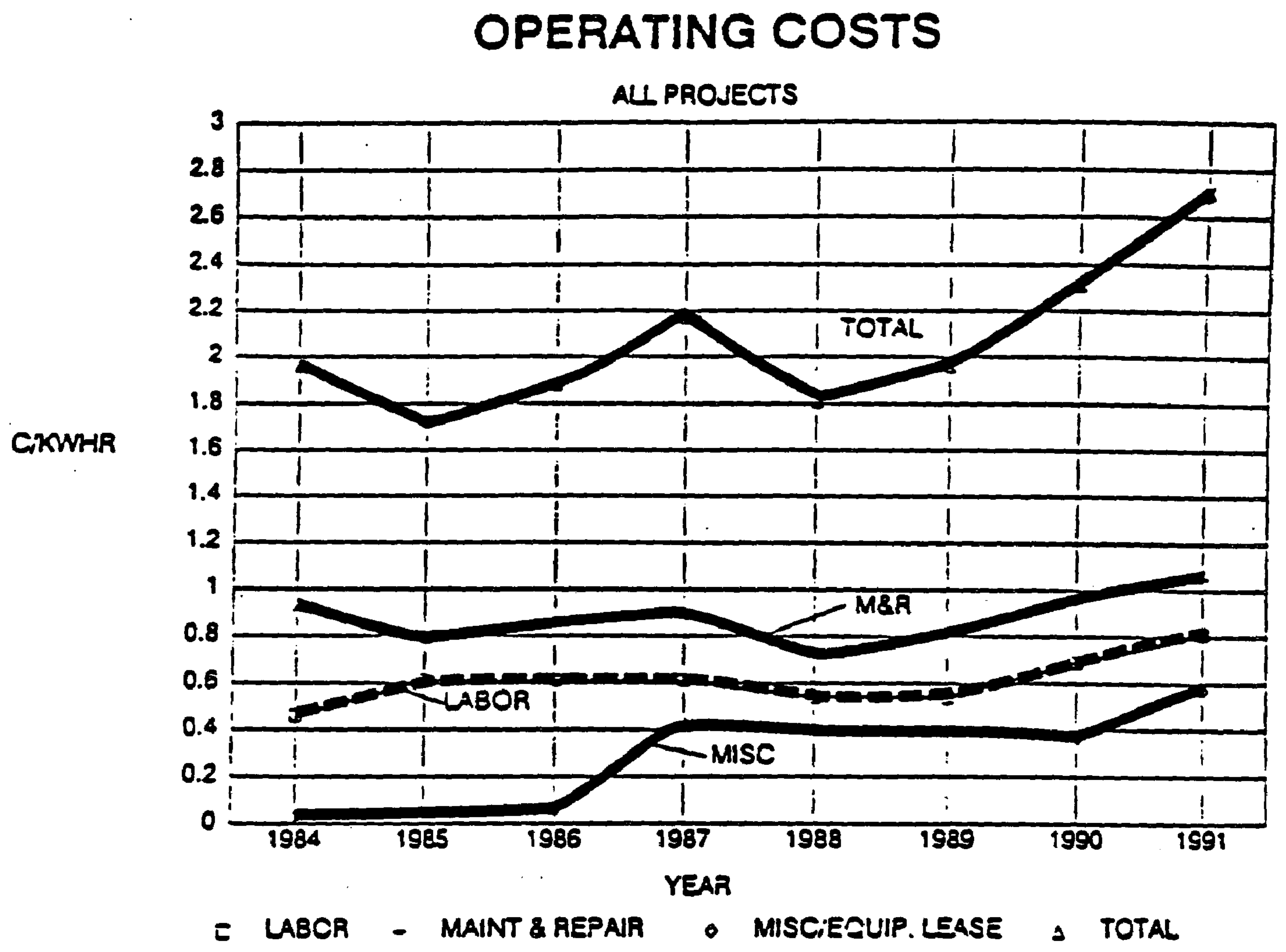


Figure 14


OPERATING COSTS
ALL PROJECTS
C/KWHR
3
2.8
2.6
2.4
2.2
2
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
TOTAL
M&R
LABOR
MISC
1984
1985
1986
1987
1988
1989
1990
1991
YEAR
LABOR
MAINT & REPAIR
MISC/EQUIP. LEASE
TOTAL

When we began operating, we believed that given the requirement of an operator at each plant, as the size of the plant increased, labor costs would tend to decrease as a percentage of total operating costs. This did not happen because as the size and complexity of the plant increased so did the size of the gas fields, engines, and gas compressor/refrigeration systems required to fuel the engines which in turn required considerably more labor to operate them. As emission requirements became more and more restrictive, low compression systems changed to high compression systems, and naturally aspirated engines changed to high compression turbocharged engines.

The three major components of operating costs include labor, maintenance/repair (this includes parts, consumables such as oil, and any work done by outside contractors), and miscellaneous equipment leases. The last category includes leasing and rental of equipment such as backhoes, pipe welding machines and any other type of specialized equipment. Other cost components that make up the total operating costs include site specific variables such as property taxes, utilities, insurance and other miscellaneous costs.

Total Capital Cost

For the purpose of evaluating a hypothetical 1,000 kw project, a capital cost distribution shown in figure 15 was assumed. Further, the assumed project total cost is $1.5 million per MW output. Based on GRS experience, the breakdown of the cost is fairly accurate and represents how the $1.5 million would be allocated. The gas collection system is approximately 13% of the total project cost; 80% is the cost of the equipment and building. This includes all gas processing equipment, engines, generators, switchgear and building to house the equipment on a fenced half acre site. The balance or 7% of the project cost is for interconnect, legal and environmental fees.

Income statement/operating cash flow

The income statement for a typical operating year for the hypothetical 1,000 kw plant is shown in Figure 16. Also listed are the assumptions including the electrical sales rate (7.0 cents/kwhr), and royalty (10%), and on line time. (80%)

The net income after tax (at 50%) is approximately $61,000. The operating cash flow, once depreciation is added back to net income, is almost $211,000.

The Internal Rate of Return, (IRR) as defined in this paper is the rate of return in which the discounted operating cash flow over the first 10 years of the project is exactly equal to the original investment.

Figure 15

CAPITAL COST ESTIMATE
HYPOTHETICAL 1,000 KW PLANT

Item	Cost	%
COLLECTION SYSTEM	$ 200,000	13.3
FEES-PLANNING/ENVIRONMENTAL	15,000	1.0
LEGAL FEES	15,000	1.0
INTERCONNECT COST	75,000	5.0
GENERATING EQUIPMENT	970,000	64.7
CONTINGENCY	225,000	15.0
TOTAL	$1,500,000	100.0

Figure 16

ECONOMICS OF 1,000 KW ELECTRICAL GENERATING PROJECT

ASSUMPTIONS

KW OUTPUT (NET)	1,000
CAPITAL COST	1,500,000
GAS REQUIREMENT CFT/DAY	700,000
ON LINE TIME	80%
OPERATING COSTS C/KWHR	2.0
ELECTRIC RATE C/KWHR	7.0
KWHRS/YR	7,446,000
ROYALTY	10.0%
DEPRECIATION (YEARS)	10

TYPICAL INCOME STATEMENT

REVENUES	$490,560	100.0%
EXPENSES		
OPERATING COST	140,160	28.6%
ROYALTY	49,056	10.0%
SUBTOTAL	189,216	38.6%
GROSS MARGIN	301,344	61.4%
SG&A (6%)	29,434	6.0%
DEPRECIATION	150,000	30.6%
OPERATING PROFIT	121,910	24.9%
TAX (50%)	60,955	12.4%
NET AFTER TAX	60,955	12.4%
DEPRECIATION	150,000	30.6%
OPERATING CASH FLOW	210,955	43.0%

In computing the IRR, a number of additional assumptions have been incorporated. The assumed operating costs do not include major capital investments in the project that will be required over its operating life, which in this case has been assumed to be 10 years. These investments include major engine overhauls, and major repairs to the gas field such as additional gas wells and/or major replacement of a significant portion of the field.

Our experience has been that a 1 MW plant would cost about $80,000 to carry out a complete major engine overhaul after 3 years of operation. Typically, major gas field investment tends to occur about 4-5 years following the original installation. Consequently, in evaluating the financial feasibility of a project we capitalize the investment in carrying out both the engine overhaul and gas field repair and depreciate each of these investments over 3 and 5 years respectively.

Finally, in evaluating the effect of various parameters on the internal rate of return, and return on net assets, the effect of financing has been neglected. Throughout the analyses I have assumed that 100% equity.

Factors Influencing Internal Rate of Return

Figures 17 to 20 illustrate the effect of various assumptions on the IRR of projects.

Energy pricing (figure 17) is by far the greatest influence on the IRR. At 7 c/kwhr each 1% increase in the price of electrical energy per year results in about a 10% increase in the IRR. Operating costs, (figure 18) effect the return to a much lesser extent. A 10% decrease in the operating cost results in approximately 8% increase in the IRR. Decreasing capital costs (figure 19) has a similar effect. A 10% decrease in capital expenditure at the beginning of the project results in improving the IRR by 20%.

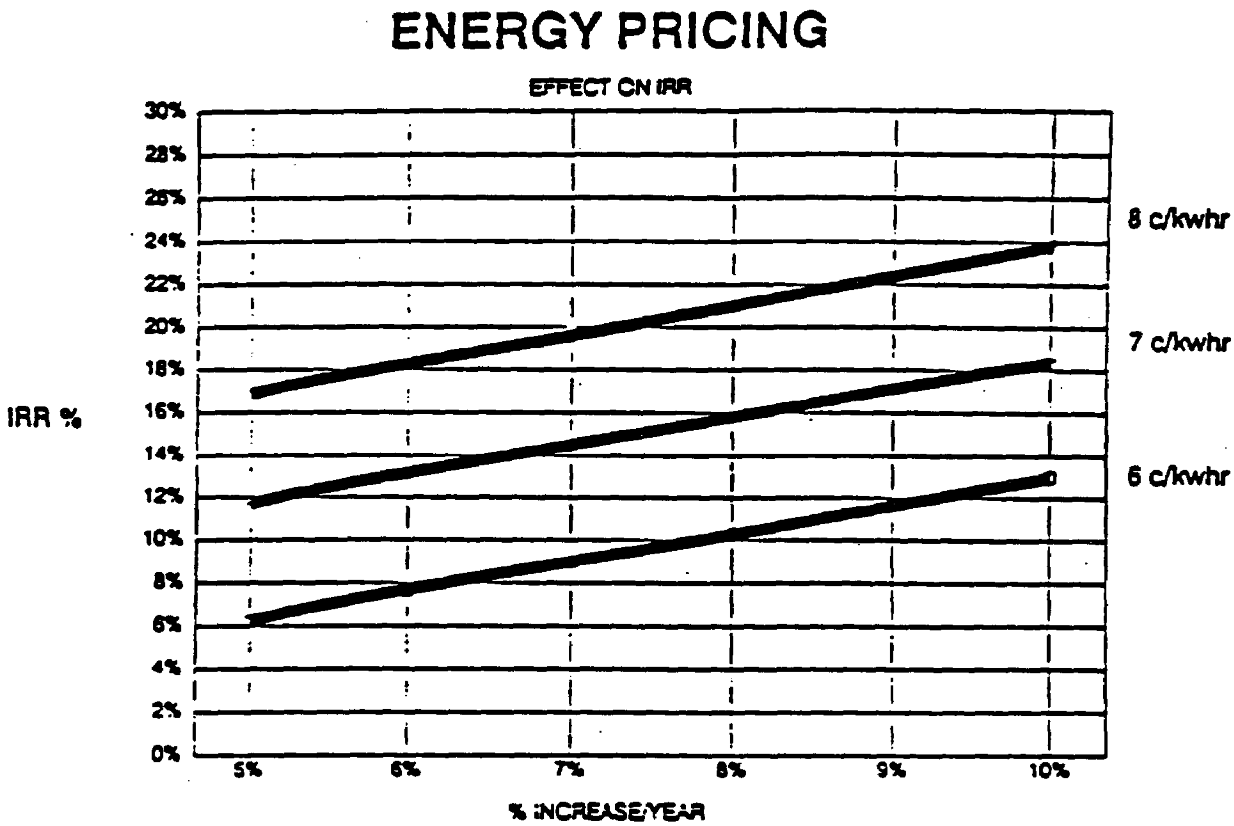
Improving operating on line time has somewhat greater impact on IRR. A 10% change in operating on line time results in approximately a 20% change in IRR.

Finally, taking advantage of the Production Tax Credits can also have a significant impact on the IRR since the credits can be worth several million dollars over the life of the project.

The future of landfill gas projects

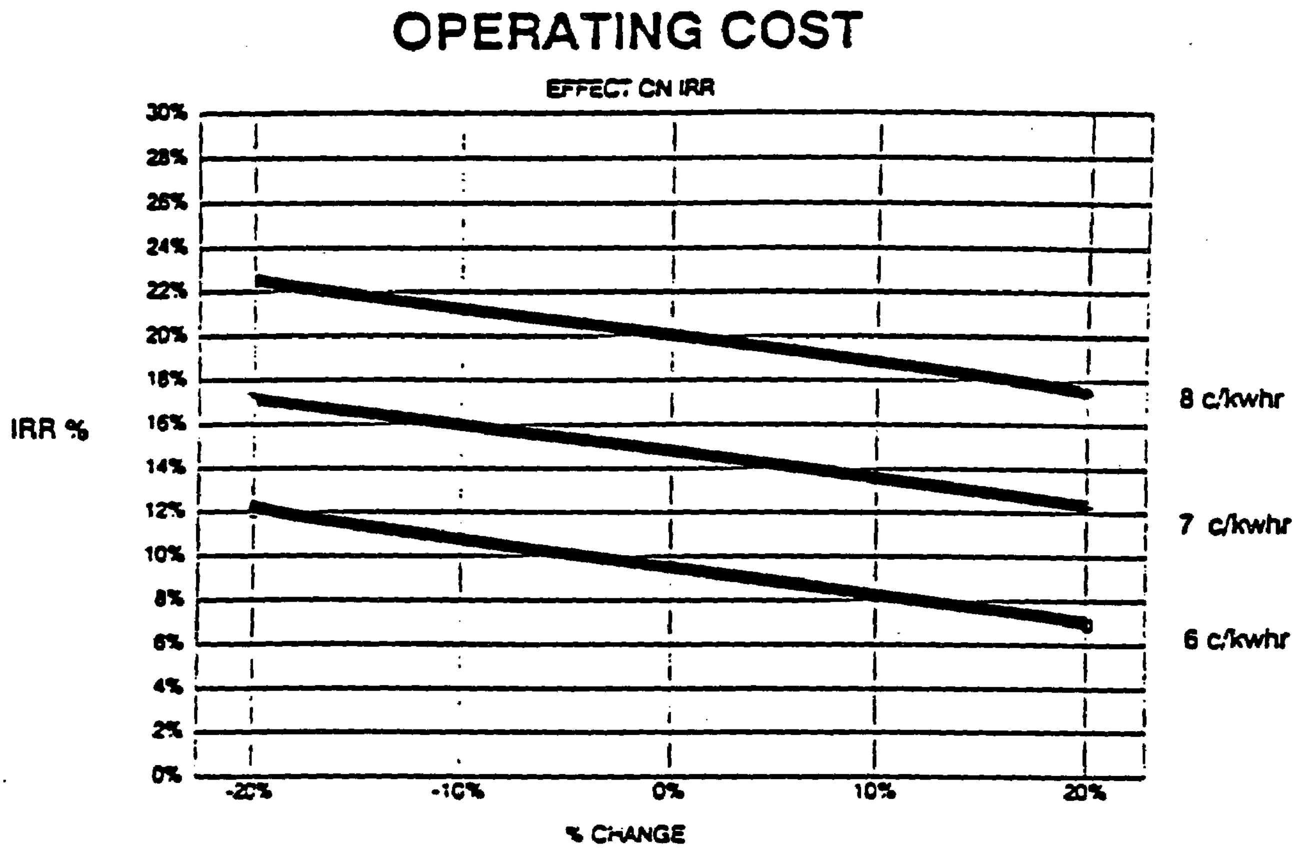
The future of landfill gas projects is very dependent, as it has always been on the sales price of the product whether that is electricity or medium BTU fuel. Based on GRS's experience, landfill gas projects need to be over 1 MW, and have an electrical price of at least 6 to 7 cents per kwhr including any capacity payments. Royalties, at this energy pricing should not be higher than 12.5%. If higher royalties are offered, the percentage should be a function of energy pricing over and above the base energy rate as inflation takes place.

Figure 17



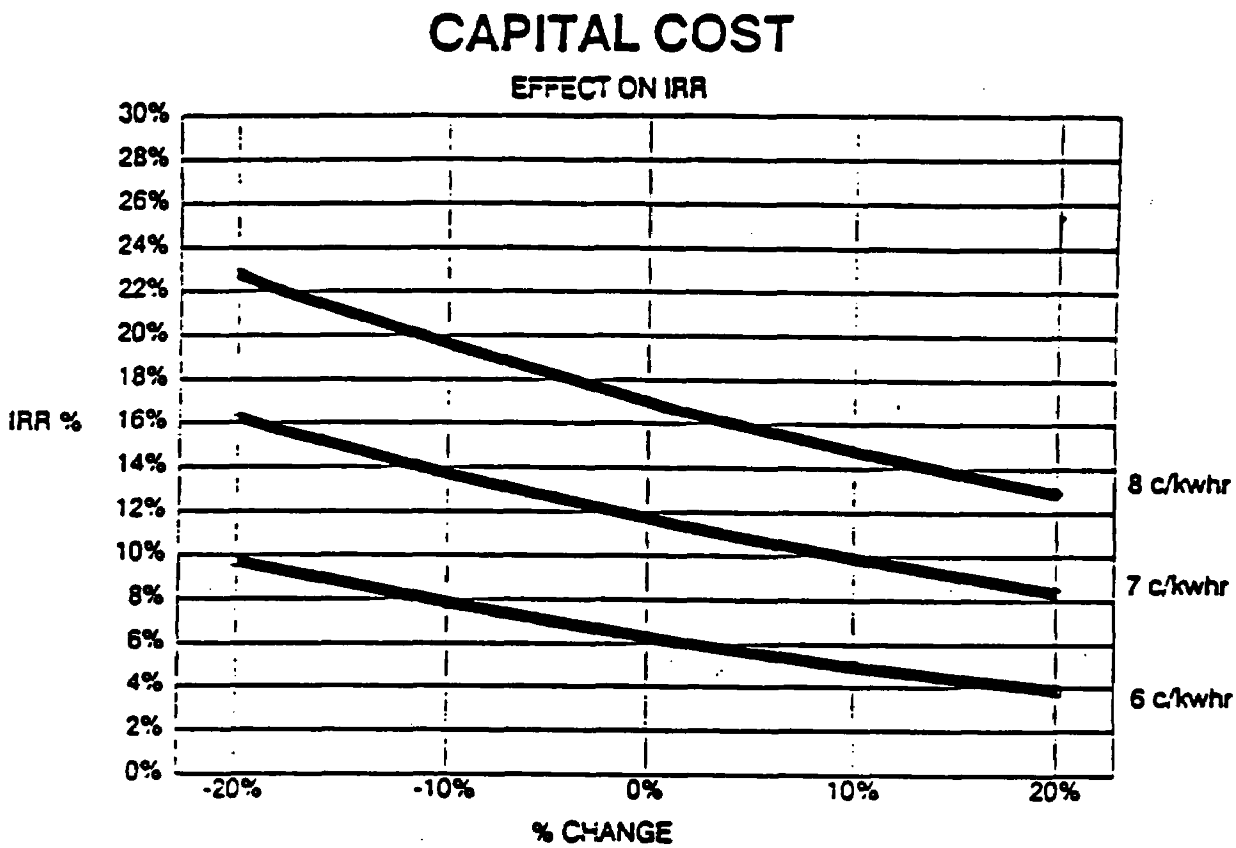
At 7c/kwhr, each 1% annual increase in energy revenues results in about 10% increase in the IRR.

Figure 18



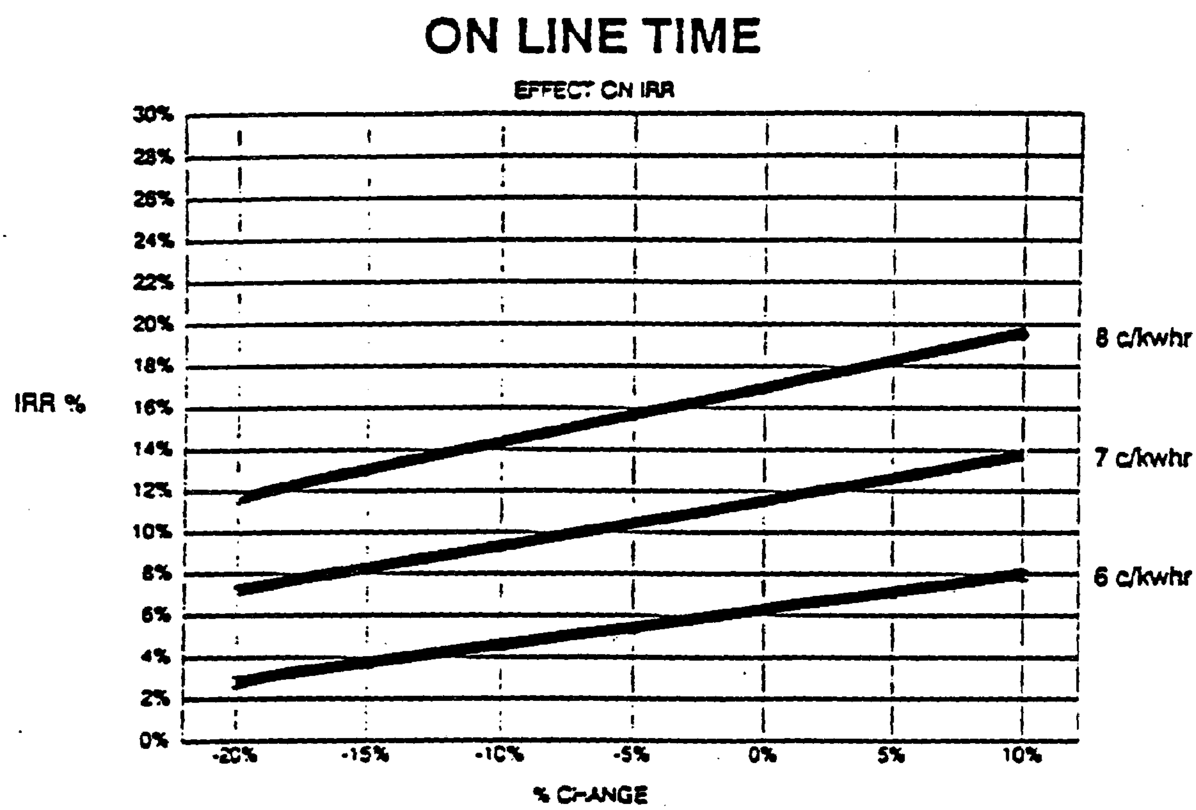
At 7 c/kwhr energy, a 10% decrease in operating costs results in an 8% increase in IRR

Figure 19



At 7 c/kwhr energy, a 10 % decrease in the capital cost results in approximately a 20% increase in the IRR

Figure 20



At 7 c/kwhr energy, a 10% decrease in On Line time results in an over 20% decrease in the IRR

Projects should make economic sense without the tax credits. Further, evaluation and economic analysis should be done over a 10 year period. The IRR of projects should be as high as possible excluding the cost of money. If all of these conditions are met the project has a fairly good chance of succeeding, provided however that the on line time is over 80% per year.

Future problems for landfill gas projects which will add to the capital costs are all of the environmental concerns that have to be satisfied. The reduction of emissions from the projects and the treatment of condensate all cost a great deal of money but add nothing to the revenues.

Operating costs must be controlled. We have found that the only way that this can be done is to develop a maintenance staff and carry out all of the equipment repairs in house. Unless plant operations personnel are available 24 hours per day to respond to problems, the capacity factor cannot be kept over 80%. A kwhr not produced is lost forever. The plant cannot be run to catch up.

In summary, gas recovery projects can be developed and developed profitably, not only for the developer, but also the landfill owner if some of the basic economic realities are kept in mind and both are willing to work together.

References

Berenyi, Eileen., Gould Robert., 1991-92 Methane Recovery From Landfill Yearbook, published by Governmental Advisory Associates, 1991

APPENDIX M

WASTE MANAGEMENT OF NORTH AMERICA, INC. LANDFILL GAS RECOVERY PROJECTS[1]

Michael A. Markham
SEC Donohue - Oakbrook Division
Lombard, Illinois

INTRODUCTION

Organic materials contained in garbage that is disposed of in sanitary landfills throughout the U.S. decomposes by an anaerobic (oxygen deficient) bacterial process which emits gas as a byproduct. This gas, commonly known as landfill gas (LFG), is composed primarily of methane (45-60%), carbon dioxide (35-50%), nitrogen (0-10%), and oxygen (0-2%). In addition there are many minor volatile and sulfur bearing constituent compounds found in LFG. Landfill gas is colorless, however, it does possess a pungent odor. The specific gravity of LFG is very close to that of air, therefore it does not readily rise or sink when released to atmosphere.

LFG does not pose a threat to society as long as it remains within the landfill or is controlled properly. If LFG should leak through the landfill surface, or through a break in the landfill ground liner, it could seep through surrounding soil formations and accumulate in pockets creating the potential for an explosion. In addition, EPA has determined that LFG contributes significant quantities of methane to the atmosphere which increases the global warming effect.

A positive aspect of LFG is its content of methane which is also found in natural gas. The heat content of LFG, by direct relationship of its methane percentage, is about half that of natural gas. However, there are many applications where natural gas as the traditional fuel can be substituted directly with LFG. Waste Management of North America, Inc. (WMNA) has committed itself to utilizing LFG to produce usable energy from what was once a wasted resource. WMNA is committed to the development of LFG recovery plants wherever they are economically feasible. WMNA uses landfill gas primarily for the production of electric energy, and in a few cases, for direct sale of medium BTU gas for boiler or process fuel. Where the project economics prohibit a positive return, most sites resort to collecting and burning the LFG in a flare.

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[1]This paper was presented at SWANA's Fifteenth Annual Landfill Gas Symposium held in Arlington, Virginia on March 24-26, 1992.

LANDFILL GAS ASSESSMENT

Prior to developing any LFG recovery project, the volume of gas available must be quantified, or a reasonable estimate established, in order to size the plant and choose the necessary equipment. This estimate will also be required when negotiating a power or gas sales contract with an electric utility or end user.

There are three ways to estimate the quantity of gas that can be generated within and recovered from a landfill: (1) model theoretical gas production, (2) conduct an active LFG flow test, and (3) install and maximize gas from a full LFG collection system. The first method involves using known information about the tonnage and make-up of the refuse material placed in the landfill over its life. Other factors include the integrity of the landfill cover material and the moisture content of the refuse. Information can be estimated for past data if unrecorded, and for future data, to establish a gas generation curve over thirty (30) years. Obviously, materials that are readily decomposable, such as residential trash, paper pulp and sewage sludge, will decompose faster and generate gas at a quicker rate than other materials such as industrial waste, plastics and construction debris. Landfills containing more of the rapidly biodegradable materials will tend to have faster gas generation rates and, therefore, gas generation curves that rise quickly, peek early and drop off rather steeply. Other landfills with materials which will decompose more slowly will have lower gas generation rates and generate less gas early, but extend usable gas production for many more years.

The moisture content of the buried refuse and landfill surface integrity will also greatly affect the rate of decomposition, and thus gas generation, and must be considered a major factor when estimating LFG generation rates. Very moist, saturated materials tend to provide an ideal environment for the microbes that carry out the bacterial process that change complex organic compounds into methane and carbon dioxide. Dry refuse will be slow to decompose and generate methane. Modern landfills, by virtue of design, are liquid tight due to the principal of "the less liquids in, the less chance of liquids out." This is primarily a response to older, poorly designed landfills whose liner and surface cover allowed landfill liquids to escape into the soils and underground water table. Because of their inherent design, state of the technology landfills have been likened to "tombs" of garbage, that without liquids will never decompose, reduce in volume, and remain monuments of our society.[2]

For LFG generation, liquids are essential. However, for LFG collection, liquids can be a detriment and therefore should be studied closely when determining the recoverability of the

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[2]New sites with the composite liners as required by Subtitle D of RCRA can enhance landfill gas production through leachate recirculation and other landfill gas enhancement approaches. However, the majority of existing sites do not have composite liners.

LFG generated within the landfill. High liquid levels within a landfill will reduce the amount of slot line which can be designed into LFG wells and thereby reduce the available area that can be influenced under vacuum. In a new well with low liquid levels, the suction of gas to the well can draw landfill liquids to the well that not only drown slot line, but also carry silt and debris to the well and infiltrate its gravel pack, thus reducing the well's effectiveness even if liquid levels can later be lowered. For WMNA LFG recovery, landfill liquid levels have been the major difference for many projects between efficient gas recovery and a continual struggle of replacing watered out wells.

The WMNA LFG program started in 1982 with one test crew dedicated to determining the amount of LFG at WMNA sites. During the period of 1986 through 1988 when WMNA employed three LFG test crews to travel the U.S. and conduct LFG flow tests to support or contrast existing theoretical gas generation curves. Typically, a series of three to four wells and four to five shallow probes per well were drilled in the landfill in a triangular or diamond pattern. Gas was then extracted from the wells for several weeks or months at varying vacuum levels while taking gas samples, temperature and flow readings at each well, and pressure readings at each probe. From this data, as well as an examination of the material that was removed during the drilling of each well, a gas generation model for the entire landfill was extrapolated.

WMNA soon discovered that good collection system considerations were as critical as good estimates of gas production in "real world" experiences. Inconsistent designs and improper installation of gas collection systems, as well as changing landfill operating patterns, caused some recoverable gas estimates to fall short and facilities to be oversized. This lead WMNA to realize that the best estimate of available gas could be obtained with the installation of a complete LFG well field, collection system and flare. The flare blower pulls a vacuum on the well field and the gas flow to the flare is measured using either orifice plate differential pressure readings or a Pitot tube pressure measurement. From this actual flow, the LFG recovery plant can be sized to accurately reflect the condition of the gas collection system. This method of determining available LFG, though definitely more accurate, takes much longer and requires more up-front resources (i.e. design and installation of well field, gas collection system and flare).

LFG PROJECT DEVELOPMENT

Economics

The economics of all potential WMNA gas recovery projects are examined closely over the life of the pending electric or gas sales contract, typically ten years. Using estimates for initial capital expenditures, electric sales revenue, income tax credits for renewable energy usage, and predicted costs and schedules for equipment maintenance, a complete project "proforma" is developed to determine the financial return. A discounted cash flow payback period of ten years or less is desired for project development. However, intangible benefits, such as positive public relations and environmental image, are always considered.

Electric Power Plants

To date, WMNA has twenty-one (21) landfill gas to electric energy plants and four (4) medium BTU LFG sales facilities. Electric generation plants have been the most attractive to develop, however not without drawbacks. Electric utilities are located everywhere, so finding a reliable customer for the electric energy is not difficult. Most landfill gas projects hinge on the price of the electric sales to the local electric utility, which can vary widely across the U.S. The electric energy is sold to the utility in the service area of the landfill. By virtue of being a small power production "qualifying facility", utilities are required to buy the electricity as mandated under the Public Utilities Regulatory Policies Act (PURPA). However, the Federal Energy Regulatory Commission (FERC) rulings have stipulated that the utilities only have to pay the "avoided cost" of energy they currently produce, (i.e. the cost of their displaced fuel) or new capacity. As a result, not all utilities offer buy-back rates that can make a project viable. Buy-back rates can be flat rates throughout the year, may have on-peak and off-peak time variations, or may have seasonal variations. When the utility company is facing the need for added generating capacity, a capacity payment may be obtained for the reliable delivery of a committed power level. In some cases, the electricity can be transported through one utility's system and sold to a second utility, otherwise known as "wheeling" power. For most project development, the lowest allowable average levelized buy-back electric rate is approximately $0.025 per kilowatt-hour (kW-hr). If a reasonable electric rate can not be found in the area, most projects are not developed.

Gas Sales Plants

The second alternative pursued by WMNA for utilizing LFG as a renewable energy source is the sale of the gas to an end user for fuel in a boiler or other process stream. The primary hurdle to developing a LFG sales facility is locating a consistent user of the gas within a reasonable distance of the landfill. Finding a customer that will be willing to take all of the LFG that the landfill can deliver, twenty-four hours a day, year round, is a major difficulty. If the customer is intermittent or cannot use all of the recoverable gas, then the gas must be collected and flared in order to control gas migration. The landfill's cost to collect and flare the gas for control is basically the same as for gas recovery, however, no sales revenue is being generated. Large industries such as automobile and chemical plants that operate around the clock are good potential customers. However, the landfills must be located within a few miles of such facilities. Other potential users of LFG are trash burning power plants and incinerators that can utilize LFG as a base fuel to perpetuate and stabilize the burning of the waste materials. For most projects, a reasonable LFG price for both the landfill and the customer can be reached; as with most cases, the LFG would displace another fossil fuel such as coal or natural gas. The price of the gas would reflect the landfill's need to offset the cost of installing and maintaining the LFG well field/gas collection system, gas compression/cleanup system, and gas delivery pipeline depending on how the agreement is structured. In the final analysis, the location of a reliable user of the LFG within a fairly close proximity to the landfill is the major obstacle for developing a medium BTU gas sales plant.

<u>Production Tax Credits</u>

Another principle factor that has enhanced the potential for developing LFG projects is the U.S. Federal Government Production Tax Credits (PTC) for renewable energy sources such as landfill and bio gases, and waste gases from oil wells, natural gas wells, and coal mines. These PTC's are based on the "barrel of oil equivalent" (BOE) of energy that is produced. A typical 3 megawatt (MW) turbine/generator using 2.0 million standard cubic feet per day (MMSCFD) can generate close to $325,000 in PTC's per year. Because the PTC's are applied on an after-tax basis, their equivalent value on a pre-tax income basis are much greater. PTC's account for approximately one-third of the revenue stream for a typical LFG project.

By current law, there are three principle rules that must be adhered to in order for a landfill to qualify for the PTC's through the year 2002:

1) The gas collection system must be substantially complete by the end of 1992. Most landfill gas collection systems that will be designed and installed strictly as a result of the new U.S. EPA Clean Air Act regulations, will not qualify for PTC's unless the qualification date is extended.

2) The landfill gas must be utilized for a beneficial purpose (i.e. power, steam or heat production that would otherwise require another source of energy).

3) The benefit from the use of the landfill gas must be gained by others beyond the recipient of the PTC's (i.e. landfills cannot generate power for their own operations and claim PTC's for the gas). Primarily, landfills must sell the gas, or the rights to the gas, to an unrelated third party.

WMNA takes advantage of the PTC's at LFG fueled electric power plants by selling the gas to a "third party" joint venture between WMNA and Caterpillar Financial Corporation (CAT Financial) called Bio-Energy Partners (BEP). WMNA develops the project and builds the plant. Soon after the plant is operating, CAT Financial acquires all of the equipment and the power producing portion of the facility from WMNA. WMNA then sells LFG to BEP, who in turn produces the electric energy and sells it to the utility. BEP also make lease payments for the use of the equipment to CAT Financial. WMNA maintains the role of managing partner by operating and maintaining the facility and LFG well field/collection system.

Lobbying efforts are being made to convince U.S. Congress to extend the qualification deadline for the PTC beyond 1992 and to extend the tax credit period beyond the year 2002. If the PTC's are not extended or replaced by other incentives many of the potential LFG recovery projects, at WMNA sites and otherwise, will probably not be developed for energy production. The landfills required by the proposed EPA Clean Air Act regulations to collect and control LFG emissions may opt to install the much less expensive equipment necessary only to dispose of the gas by flaring. This would be a great loss of a relatively untapped alternative energy source.

LFG RECOVERY PLANT EQUIPMENT

Standard Designs

In 1987, the WMNA landfill gas recovery program had estimated the potential for up to eighty (80) gas recovery plants by the early 1990's. To better prepare, WMNA adopted a philosophy of using a "standard plant" design to offset repetitive architectural and engineering costs associated with the design of such a large number of facilities. The "standard design" primarily incorporates separate fuel gas collection/compression system(s) room, gas turbine or engine/generator(s) room, a viewing room and/or control room, all enclosed in a concrete block building. Located outside would be the utility interconnect with high voltage transformer and switchgear, as well as some of the ancillary equipment such as turbine air intake filters, engine radiators, exhaust silencers, gas aerial coolers, and waste liquid holding tanks. The fuel gas compressor room is designed to meet National Electric Code (NEC) Class 1, Division 2 requirements for hazardous environments. The motive for the use of the concrete block is two fold; first, to provide maximum noise attenuation from the operating equipment, and secondly, to provide an aesthetically pleasing image for public relations purposes. Some of the more recently built facilities, mostly the smaller plants, have modified the "standard design" to reduce project capital costs in order to generate a more attractive financial payback over the project life.

WMNA's twenty-three LFG fueled electric power plants all use combustion engine technology developed by either Solar Turbines, Inc. of San Diego, California (gas combustion turbines), or by Caterpillar Inc. of Peoria, Illinois (internal combustion reciprocating engines). At these twenty-three sites, WMNA has twenty-five (25) Solar Centaur turbines (4500 hp, each), two (2) Solar Saturn turbines (1200 hp, each), and twenty-four (24) Caterpillar 3516 SITA engines (1138 hp, each). The installed capacity of these electric generators is approximately 96 MW of power. Through the end of January 1992, this equipment had accumulated nearly 750,000 hours of operation.

After the initial turbine plants were installed in Wisconsin in 1985 (Omega Hills and Metro) and the initial engine/generator plant was installed in Colorado in 1986 (County Line), Caterpillar and Solar Turbines continued to improve the technology that had been developed for LFG fuel service. Caterpillar continued to make adjustments to the engines to ensure necessary maintenance and overhaul intervals would be cost effective. Solar continued their development of the Saturn turbine that allowed WMNA the option of a smaller LFG fueled turbine/generator unit. Based primarily on the commitment of these two companies to

WMNA's LFG recovery program, the Solar Centaur turbine and the CAT 3516 engine were chosen as the standard equipment for future LFG fueled power generating facilities.

Utilizing standard model equipment at the plants allows for shared experience to minimize duplication of the learning curve, allows holding joint training seminars for plant operators from around the country, and makes possible common stocking of major spare parts. All equipment operating problem details from the WMNA plant monthly operating reports can be pooled to determine if a particular problem experienced is identical among all units and, if so, a common solution can be engineered to resolve the matter. WMNA also holds annual seminars for their plants operators to provide training and information on subjects such as turbine, engine, and compressor operations and maintenance, electrical system trouble shooting, plant safety, lubricating oil analysis, and environmental policies and procedures. In addition, open round table discussions are encouraged to have operators share new ideas, air common grievances, and promote cooperative relationships between facilities. Lastly, WMNA stocks a spare turbine engine and gearbox, spare blowers, compressors, large compressor electric motors, and a spare reciprocating engine in order to reduce downtime resulting from major equipment failures. If the equipment at each plant were different, each site could not afford to stock their own spares. Awaiting equipment repairs or new equipment from the factory at the time of a failure could cost the program hundreds of thousands of dollars in lost electric revenue and tax credits each year.

Turbine/Generator Standard Equipment

The most widely used turbine/generator at WMNA plants is a Solar Centaur GSC4500 LFG fueled turbine/generator set. The turbine is a slightly modified natural gas, simple cycle, single shaft, industrial turbine engine; the only major modification made to the natural gas version turbine was to double the fuel gas control system components and fuel injectors and to enlarge the fuel gas manifold in order to account for the LFG fuel having approximately one half the heat value of natural gas. The turbine/generator set is rated at 4500 horsepower (hp), and is supplied with a 3000 kW generator, 4,160 volts, 60 hertz, 0.8 power factor. The turbine at rated output and standard conditions (600 feet above sea level, 50 degrees Fahrenheit (°F) ambient air temperature and standard inlet and exhaust duct losses) requires approximately 40 million BTU's per hour (MMBTU/hr), lower heating value (LHV), or about 2 MMSCFD of landfill gas at 480 BTU/SCF.

The other turbine/generator set in use by WMNA sites is a Solar Saturn GSC1200R LFG fueled turbine/generator. This turbine model is an exhaust heat recuperated cycle turbine rated at 1200 hp. Again, the turbine is basically a natural gas turbine with a modified fuel system to account for the lower heat value of the LFG fuel. The electrical generator is rated at 950 kW. The Saturn typically requires approximately 11 MMBTU/hr (LHV) at rated output and standard conditions. Both Saturn turbines at WMNA plants are installed as the second turbine/generator unit at the site.

Engine/Generator Standard Equipment

As mentioned previously, WMNA uses the Caterpillar 3516 SITA engine at facilities where reciprocating engines are installed. This engine is a slightly modified spark-ignited natural gas engine, four stroke cycle, V-16 cylinder configuration, turbocharged aspirated, and after cooled. The engine is rated at 1138 brake horsepower (bhp), operates at 1200 rpm synchronous speed, and is supplied with an 800 kW generator, either 480 or 4160 volts. Two versions of the CAT 3516 SITA engine are currently available. One version, the "high pressure" model, requires 35 pounds per square inch gauge (psig) fuel pressure to the engine where a standard type carburetor mixes the fuel and combustion air. The second version, a "low pressure" model, requires only 2 psig fuel pressure at the engine where the fuel/air ratio is controlled in a special mixing valve at the air intake prior to the turbocharger. This "low pressure" model retains the full power rating of the standard engine and actually uses slightly less fuel. However, the primary advantage of the "low pressure" model is the lower power consumption of the landfill gas collection/compression system that must compress the gas to only 2 psig verses 35 psig for the standard "high pressure" model.

The exhaust from the CAT 3516 engines is not cataliticly treated, however, the engines do utilize lean-burn technology that allow nitrous oxide (NO_x) emissions to approach Caterpillar quoted levels of 2 grams per brake horsepower-hour (g/bhp/hr) for the "high pressure" engines. Field exhaust emission tests on "low pressure" engines have shown that NO_x levels of 4 g/bhp/hr are easily achievable. The engine emission levels are a function of the engine timing, air/fuel ratio, and the specific fuel gas composition. WMNA projects permit air emissions based on the EPA New Source Performance Standards (NSPS) for stationary equipment that limit any one pollutant to 250 tons per year. For reciprocating engines, the limiting pollutant is NO_x. For most areas, this limits the number of engines at a facility to four high pressure engines or three low pressure engines in order to stay below 250 tons per year NO_x. Beyond these limits, the permit application would require a fairly elaborate, extensive, and often expensive, review under the Prevention of Significant Deterioration (PSD) program. For this reason, planned facilities with enough available gas to support more than four engines often decide to use combustion turbine technology, which emits much less NO_x and slightly less carbon monoxide (CO) at comparable horsepower than reciprocating engines, rather than submit to the PSD review.

Fuel Gas Compressor Systems

The required fuel pressure at the Centaur turbine is typically 175 psig which is delivered usually by a dedicated fuel gas compressor (FGC) system. Most Centaur FGC's are rated for 1800 standard cubic feet per minute (SCFM) at an inlet gas pressure of 6 inches of mercury vacuum and a final discharge pressure of 185 psig. Except for the first four systems built, WMNA's Centaur FGC's utilize a two stage compression process using a positive displacement, rotary lobe blower first stage and an oil injected, screw type compressor second stage. Prior to the plant, each gas collection system has an underground liquid knockout tank to collect the major portion of liquids that are carried off the landfill with the gas. Inside the plant, an inlet scrubber vessel, primarily a large vessel for velocity reduction with a stainless steel wire mesh pad, removes additional liquids and particulate (dirt and debris). After each stage of compression, the gas is cooled in an aerial heat exchanger to further remove moisture from the gas. Injected oil and gas are separated after the second compression stage and prior to cooling. Liquids and particulate are removed again from the gas in a gas filter after cooling. Prior to exiting the FGC system, the gas is reheated in a gas-to-gas heat exchanger by hot gas exiting the oil/gas separator vessel. This raises the gas temperature 20 to 40°F above the gas dew point to ensure that no liquids form prior to reaching the turbine. Finally, a final gas filter (0.3 micron absolute) mounted just prior to the turbine/generator acts as the last barrier for particulate and water remaining in the gas. No additional gas treatment other than compression, cooling, filtration, and reheating are performed.

Of the twenty-five Centaur FGC systems, seventeen use Sutorbilt blowers for the first stage of compression and Howden compressors for the second. Another three FGC's use Roots blowers for the first stage, and again, Howden compressors for the second stage. The most recent FGC system installed for a Centaur turbine utilizes a Roots blower first stage and a Dresser-Rand TVC, an oil injected, screw type compressor, for the second stage. Additionally, WMNA's first four Centaur turbine power systems used a Roots blower for the first stage of compression, and Hall reciprocating compressors for second and third stages of gas compression, yielding the same rated discharge pressure and flow.

Reciprocating engine FGC systems are very similar to the turbine fuel compressors in design philosophy, however, the engines require much less fuel at much lower delivered gas pressures. Because of this, most engine/generator facilities utilize a single FGC system for all of the engines installed at the site. For the "high pressure" engines, two different systems are in use: (1) a two stage, rotary lobe Roots blower system rated for 400 SCFM at one site, and (2) a single stage system with two Dresser-Rand TVC oil injected, screw compressors in parallel rated for 1600 SCFM at two sites. The first system supplies gas for a single 3516 engine, whereas the second supplies fuel gas for four 3516's. Both deliver the gas at 35 psig to the engine and utilize the same compression/cooling/reheat philosophy as the turbine FGC's. In 1991, however, the engine facilities did not utilize the final gas, 0.3 micron filter as the turbines do.

The "low pressure" engine plants also use a single FGC system for all of the installed engines. However, because the required fuel pressure is only 2 psig, a single stage rotary lobe blower is used. The single blower FGC system takes the gas from a vacuum and boosts it to approximately 7 psig, cools, filters and reheats the gas and delivers it to the engines at 2 psig. All of the "low pressure" FGC systems have been built using Roots blowers. Vessel and cooler sizes have been adjusted to two standard systems rated at 800 and 1200 SCFM.

The 800 SCFM system can supply fuel gas for 2 to 3 engines at full load depending on the BTU value of the gas. The 1200 SCFM system is sized for 3 to 4 engine facilities.

Plant Operations

In budgeting operations at WMNA's LFG recovery plants, two operating criteria are reviewed annually to predict plant output for the approaching year: (1) equipment on-line time, and (2) plant capacity. Plants are required to anticipate equipment routine maintenance, operational problems, major overhauls and gas well field changes in order to estimate energy delivered to the utility or gas sales to the end customer. These energy delivery projections are used to budget revenue. In addition, each plant must submit a budget for expenses required to operate and maintain the facility.

Equipment on-line time is a determination of equipment availability taking into account equipment maintenance, potential operating problems, and any planned changes to the system (i.e. installation of a new generating unit that would require downtime to make the electrical tie-in). WMNA's equipment is typically budgeted to operate ninety-three percent (93%) of the time. This 7% of equipment in operation, or downtime, includes all equipment and facility maintenance, and all potential operating problems. To reiterate, 93% on-line is not the budgeted plant availability, but is a budgeted time for each individual turbine or engine/generator to be producing power. For facilities in their first year of operation, the expected on-line time is reduced to 85% to allow for completion of start-up related problems or changes, and also to allow the plant operator to build experience and confidence in his job without undo pressure.

Even though the budgeted on-line times are 93%, many of WMNA's facilities have exhibited that better performance is possible. Nine of WMNA's nineteen facilities in operation for the full year in 1991 operated above the budgeted level. One facility, the DFW turbine/generator plant in Lewisville, TX, operated at an equipment on-line time of 98.5% for the year. Overall, turbine/generator equipment averaged 93.9% on-line time excluding well field/gas collection system problems, and 86.0% including them. Engine/generator equipment for 1991 averaged 95.5% and 89.6% on-line times excluding and including LFG well field problems, respectively.

Budgeted plant capacity, as well as plant on-line time to some degree, is in direct relationship to the volume of LFG fuel that can be recovered. LFG, as the fuel, is the singular factor that determines the power output level that the plant can sustain. For facilities with power capacity greater than the available gas volume, this results in operating the generating equipment at some partial load below full rating. If the gas shortage is even more severe, shutting down individual generating units may be required. This must be considered when budgeting plant performance and equipment on-line time.

For facilities with LFG supplies that are ample enough for full plant output, budgeting power output, and therefore energy sales, should be more predictable. For reciprocating engine driven generators, power output is primarily fixed by the rating of the equipment, and ambient conditions play little role affecting capacity. However, because the first step in the thermodynamic process of a gas turbine is to compress the combustion air prior to ignition, cooler air which is more dense and less humid requires less compression work to be performed by the turbine, and allows more work to be converted into electrical energy output. Therefore, ambient temperatures affect gas turbine driven generator outputs dramatically from season to season, and from geographical location to location. In summer, with ambient temperatures averaging 80 to 90°F in the daytime, and 60 to 70°F at nighttime, average expected Centaur turbine power output would be 2800 to 2900 kW. In winter with much colder ambient temperatures, WMNA has experienced Centaur turbine output improvements by as much as 600 kW. At the DFW plant in Texas, and an inlet air evaporative cooler is used in late Spring and Summer to lower inlet air temperatures to 60°F. (Because of the principles evaporative coolers work under, dry, warm air conditions create the most efficient conditions for their use.) Budgeted power capacities assume average climatic conditions for each facility, however, nature does not operate on averages. As a result, weather conditions can affect plant performance, but over the year, the conditions average out.

Other operator controlled factors may also improve plant performance. On average WMNA knows that the plant parasitic loss, that is the power to operate the FGC and facility lights, heat, etc., for a turbine/generator facility is about 17%, for "high pressure" engine/generator facilities, about 13%, and for "low pressure" engine/generator facilities, less than 10%. Some turbine facilities with multiple generating units and FGC's, have manifolded the FGC systems together with cross-over valves. This allows the facility in conditions of LFG shortages to operate all generating units from fewer FGC's, thus reducing parasitic load. Additionally, the cross-over valves allow maintenance on one FGC system, typically required more often than turbine maintenance, to be performed while operating the associated turbine off of excess capacity from the other FGC systems. At other facilities that operate under day to night on-peak and off-peak utility rate changes, lost electric sales due to planned maintenance outages can be minimized by performing work at night when rates are lower. Each of these operational variations improves plant net performance and maximizes energy output sales to the utility.

OPERATIONAL PROBLEMS

Since WMNA projects began operating in 1986, much experience has been gained through experience regarding problems with operating and maintaining LFG recovery equipment. Three (3) operational problems that have been encountered by WMNA, two which remain a continual struggle, greatly affect plant capacity, equipment maintenance costs, and equipment on-line time.

Fuel Gas Compressor Oil Carryover

In April 1988, WMNA learned through experience, the effects of oil and liquid carryover into a turbine engine. It was discovered after a turbine failed at the Omega Hills gas recovery plant in Menomonee Falls, WI, that a black, carbon buildup was developing at the turbine fuel injector tips. The turbine had 21,000 hours of operation and had been inspected by Solar field service personnel four months previously. It was determined that the cause of failure had been carbon deposits at one injector tip sufficient enough to divert the fuel gas path to the area between the inner combustion chamber and the outer turbine liner. This diverted gas acted as a torch and eventually burned a hole in the side of the turbine. As a result of the failure, precautionary measures, primarily removal, inspection and cleaning of all fuel injectors at quarterly maintenance intervals, were established. This maintenance, added significant equipment downtime which in turn reduced electric sales revenues.

An equipment evaluation at Omega Hills was also made. It was determined that the FGC process, which utilized reciprocating compressors with oil drip lubricators, was at fault and that modifications could be made without changing the major system components which would improve liquid and oil removal from the gas prior to reaching the turbine.

Before the new modifications could be thoroughly tested, another turbine experienced a failure from the same cause. This turbine, located at the GROWS facility outside Philadelphia, failed with a little more than 17,000 hours of operation and incorporated a FGC system with an oil injected, rotary screw compressor, rather than a reciprocating compressor. Turbine fuel injectors had been inspected and cleaned quarterly; this indicated that sufficient carbon deposits to cause a failure could accumulate faster than the operator was removing them.

By the time a complete failure analysis could be performed, the results of the FGC changes at Omega Hills were apparent; the oil and liquid carryover to the turbine had been reduced almost 100%. The principle component achieving these results was a final fuel gas filter manufactured by Pall Well, that was installed in the turbine room just prior to where the gas enters the fuel control system on the turbine skid. It was immediately decided to retrofit all of the existing turbine systems with the filter to prevent future turbine failures.

Most of the filters have now been in service at least one year and all indications are that they are performing very well. Turbine fuel injectors remain so clean that only semiannual spot checks are made for fuel injector carbon buildup. The final analysis is that WMNA turbine facilities have removed a potential failure mode and reduced the amount of necessary maintenance downtime.

Reciprocating Engine Ash Deposits

Through the experience of Caterpillar and WMNA, the choice of lubricating oil for the CAT

3516 landfill gas engines has been primarily standardized to a modified natural gas engine oil. The oil has extra additives to prevent attack from corrosive chlorine, fluorine and sulphur bearing compounds found within the landfill gas fuel. An oil consisting of a total sulphated ash content of approximately 1% and with a nominal total base number (TBN) of 10 has been found to be ideal for combating engine acids formed by these compounds. Oils with higher TBN and ash content will maintain their acid neutralizing effects longer and thus lengthen oil change intervals. However, experience has shown that excessive ash in high TBN oils can have a detrimental effect to the cylinder heads over time. Oils with low TBN and ash, similar to standard natural gas engine oils, tend to be depleted of their neutralizing agents within several hundred hours and therefore make oil changes frequent and cost prohibitive. Most WMNA engines are on 750 hour oil change intervals, but are modified depending on the makeup of the landfill gas fuel. Oil analysis for metals, TBN, oxidation, nitration, viscosity, and water content taken at several intervals between oil changes also benefit the plant operators in deciding when to change oil and filters.

Even the 1% total sulphated ash oil that is in current use leaves hard, white deposits on the cylinder heads, piston crowns, inside the exhaust manifold and on turbocharger wheels and housings. The deposit material has been tested and determined to be a combination of oil additives and silica. The oil is apparently "blowby" getting past the piston rings and/or through wear in the intake and exhaust valve guides. The silica contribution to the formation of the deposits remains in debate. Some people are convinced that the silica is carried with the LFG from the landfill in gaseous form, and thus cannot be filter out. Others argue that the silica is brought in with the intake combustion air. However, oil analysis of off road vehicles in much worse service environments compared to oil analysis of stationary LFG engines inside an enclosed building do not support the air intake claim.

Many theories have been proposed on how best to reduce the deposit buildup. Caterpillar believes that dehydration of the LFG fuel by refrigeration will remove the silica from the gas, and thereby reduce the deposit material strictly to oil ash which is common for all natural gas engines. WMNA has installed a gas dehydration unit at one facility which appears to have reduced maintenance levels. WMNA has recently installed a Pall Well filter at one engine site similar to the turbine fuel gas filters. Not enough operating experience has occurred to make even a preliminary judgement of the filter's performance. WMNA, in conjunction with Caterpillar recommendations, has also tried water injection into the engine cylinders to steam clean the deposits from the heads and pistons; preliminary conclusions suggest that this might have some merit if starting with a new engine with minimal oil consumption and no initial deposits. In a final case, WMNA has had a complete cylinder head and piston crown coated with a ceramic material that prevents the deposits from adhering to the metal; to date, this option seems to offer the most promise, however, the cost of the coating might prove excessive for the benefit derived.

In the end, it appears that the deposits accelerate the formation of even greater deposits. As the engine breaks in and oil begins to blowby the piston rings, and wear occurs in the valve guides, silica begins to react with the oil to form deposits on the piston crown and head. As the deposits increase, areas of deposits begin to flake off and exacerbate wear between the cylinder liner and piston rings, and between the valve stems and guides. As more wear occurs, more oil enters the piston chamber and more deposits are formed, which in time create more wear; the cycle soon becomes circular and deposits theoretically increase exponentially.

Current maintenance schedules call for top end overhauls at 8,000 to 9,000 hours of operation. Most cylinder heads, when removed at this time, are covered by deposits up to 1/8 inch thick. The cylinder heads are typically replaced with rebuilt heads, however deposits from the top of the piston must be removed. The deposits are usually so hard that only a hand-held grinding wheel can remove them in a timely manner.

Prior to planned maintenance, several operating problems can result from the deposits. Pieces of flaked-off deposits get lodged between exhaust valve faces and seats and prevent full closure of the valves; this small opening provides a path for hot gases and flames to escape during the combustion stroke and causes concentrated heat stress, or "guttering", to occur. Deposits on piston crowns as small as 1/8 inch can change the effective compression ratio of a cylinder and cause detonation or pre-firing; this can have many negative mechanical effects on the engine. Lastly, turbocharger wheels with several thousand hours of operation typically exhibit grinding marks on the blades from contacting deposits on the housing. If grinding is severe, the turbo wheel may become unbalanced and wipe out the entire wheel and/or the bearings. All of these resultants of the ash/silica deposit buildup cause increased downtime, equipment maintenance costs and lost electric revenues. WMNA continues to search for the answer to these problems.

Gas Well field/Collection Systems

As mentioned previously, LFG well field, collection system, and gas shortfall problems are the primary factors that determine the relative success of the project. However, because of the uncertainty of predicting future landfill operations and volumes, the complexity of designing gas well fields and collection systems, and the difficulty in hiring, educating, and retaining proficient well field technicians, many times this factor is the most difficult to control. All of the well field/gas collection system problems in 1991 combined to total nearly 100% of WMNA plant output reductions and 56% of all equipment downtime.

Many landfills have installed gas control systems and flares to prevent LFG migration from the landfill property. Under these circumstances, collection of nearly all of the gas is paramount to succeeding with the task. Consequently, the "quality" of the gas collected is of minimal importance to the operation of the flare.

For LFG recovery however, the quality of the gas, that is the content of the primary constituents i.e. methane, carbon dioxide, nitrogen, and oxygen, is of utmost importance to prevent short term equipment malfunctions, to promote long term equipment life, and finally, to ensure that LFG generation will continue and be productive for many years in the future. WMNA LFG well field systems are typically "tuned" to maintain 53 to 54% methane in the total gas "quality" at the plant. Lower methane concentrations give rise to higher carbon dioxide, nitrogen and oxygen levels. Oxygen in the plant can create risks due to potential explosions if in high enough quantities, and can accelerate oxidation of the equipment from corrosive attack. Rise of carbon dioxide, nitrogen and oxygen levels can indicate breaks in the landfill cover material, breaks in the gas collection system, or more importantly, stress of the bacterial microorganisms within the landfill due to air intrusion. If excessive, air intrusion into the landfill can slow or stagnate the gas generating bacteria for many years before they can regenerate and begin producing usable LFG again. Air intrusion in its worst extreme can also create underground oxidation, a landfill fire.

Many LFG recovery and power plants are installed to replace or substitute gas control flare systems. Certain assumptions are made during the project development of the power facility regarding plant output over the life of the pending utility contract, usually for ten years. However, LFG fuel quality or collection system limitations may not allow the power plant equipment to extract the necessary fuel to operate the plant at the expected level. If so, economic expectations of the facility will not be met. If ample fuel *can* be extracted from the landfill to operate the facility at maximum output, the gas recovery plant may not be performing its function to collect all of the gas being generated and thereby controlling LFG migration.

At one WMNA location it is necessary to operate both turbine/generator units at a partial load to control gas migration. However, because of the inefficiency of the turbines operating below full load and design flow restrictions of the FGC systems which require operating both FGC's and therefore create higher plant parasitic loads, plant output levels are less than could be achieved using only one turbine/generator. As a result, plant electric sales suffer to maintain gas migration control.

Determining the capacity of LFG electric generation facilities is a delicate cooperative effort between estimating the volume of generated and recoverable LFG, designing the gas well field and collection system, and sizing the eventual LFG fueled power facility and equipment. All of these factors will affect the operation and performance of the power plant once completed. Unfortunately, each of these three factors may be considered independently; 1) by a gas testing or assessment group that estimates the volume of gas being generated, 2) by the collection system design engineer that places the locations of the recovery wells on the site plan and sizes the collection system header, and 3) by the project manager who decides the size of the facility and what power generating equipment will be installed. If these parties do not communicate effectively in the early stages of the project, the results at times have been a landfill with off-site gas migration problems, a gas collection system that is supplying 100% of its design flow, and a power facility operating below the expected plant output capacity; no one benefits in this scenario.

Another well field and collection system problem that affects LFG recovery is the continual battle of installing and maintaining gas wells and collection systems in active landfill areas. After gas wells and collection header pipe are installed, many landfills are permitted vertical expansions that allow more refuse to be deposited on top of the existing collection system. Wells can be extended, but only with solid pipe, thus reducing the effective zone of the well to the lower portion of the landfill. Collection header pipe, however, usually gets buried below twenty, thirty, even forty feet of new trash. Pipe breaks or collapses due to settling of the new refuse usually dictate new header systems to be installed because the total depth below the surface is prohibitive. Other times, a section of landfill with gas wells that has been inactive for a time will be reopened; the area around the well will be exposed creating potential for air intrusion. As a result of these problems, power plant equipment may be required to shutdown or reduce output levels in order to perform collection pipe repairs or prevent pulling oxygen into the landfill.

Landfill gas, arguably, is a potential hazard, and less arguably, is a nuisance odor. LFG has also become a fuel for electric power generation. However, LFG recovery must be able to co-exist with landfill operations, control gas emissions into the atmosphere, and provide usable fuel for power generation. At WMNA facilities, as well as most other gas recovery operations, power generation sales account for only a fraction of the total landfill revenues. In addition, odor and gas migration control may be part of operating permit requirements, and will definitely affect public relation efforts. As a result, landfill operations and gas migration control will not be compromised to benefit power generation.

Gas well field, collection system and gas shortfall problems pose the greatest challenge to LFG recovery power generating facilities with regard to equipment performance and overall project success, as well as achieving the dual purpose of maintaining gas migration control from the landfill site. Gas recovery facilities will always walk a fine line between being oversized for the volume of available LFG and operating below full output capacity, and being undersized and not able to control odors and gas migration from the landfill property. A delicate balance between these two goals must continually exist.

APPENDIX N

I-95 LANDFILL GAS TO ELECTRICITY PROJECT UTILIZING CATERPILLAR 3516 ENGINES[1]

Bill Owen
Michigan Cogeneration Systems
San Diego, California

Introduction and General Overview

The I-95 Landfill is operated by the County of Fairfax, Virginia and is located approximately 25 miles south of the nation's capital. The facility is owned and operated by Michigan Cogeneration Systems Inc. (MCS) of Novi, Michigan.

The facility began commercial operations in January 1992 and consists of four (4) Caterpillar 3516 spark ignited engines, each capable of producing 800 Kw. The facility utilizes landfill gas (LFG) as its only fuel source and produces 3200 Kw gross. After internal parasitic losses the facility nets approximately 3050 Kw for export to the local utility, Virginia Power. The facility is operated and maintained by one full time employee of MCS.

History of Project

Since the mid 1980's the County of Fairfax had attempted to work with several developers in an attempt to develop a LFG to energy project at the I-95 Landfill.

In February 1990 the County issued an RFP from which MCS was selected as the most qualified bidder. In December of 1990 MCS and the County executed an agreement giving MCS the gas rights to the landfill. MCS began engineering the project in late February and synchronized with the utility in late November, approximately 10 months. The month of December was used to wring out the system, and MCS went into commercial operations in January 1, 1992 selling firm capacity and energy to Virginia Power under a 20 year contract at an average rate of 5.2 ¢/kWh. The cost of the project was approximately $3,200,000.

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[1]This site was featured on the landfill gas tours as part of the Solid Waste Association of North America's fifteenth annual Landfill Gas Symposium held in Arlington, Virginia on March 24-26, 1992.

Landfill and Landfill Gas System
The I-95 Landfill is an active landfill which receives nearly 5,500 tons of refuse per day. The landfill is adjacent to Route 1 and Interstate 95 and is north of the Occoquan River. The landfill is titled in the name of the United States with the District of Columbia as the "beneficial owner". Fairfax County runs the landfill through a Memorandum of Understanding between the two governments.

The landfill was opened in 1972. The landfill has since expanded to 290 acres with nearly 17.5 million tons of refuse in place.

An Energy Resource Recovery Facility has been constructed at the site and is currently burning 3,000 tons per day of the refuse stream. The plant currently produces 70 Mw of power for sale to Virginia Power.

The County operates a perimeter collection system consisting of approximately 50 wells. This system is operated to provide off-site landfill gas migration protection and has extraction wells both within and outside the refuse.

The main collection system is operated and maintained by the County under contract to MCS. The main collection system currently consists of 15 vertical wells covering approximately 22 acres. The wells vary in depth from 50 to 100 ft. Since commercial operation began (1/1/92) the collection system has provided 100% of the power generation systems needs. The power generation station consumes 1150 cfm of landfill gas. For the first three months of operation the gas continues to maintain its high quality at approximately 55-58% methane. As part of the County's closure plan for a portion of the landfill, an additional 65 vertical wells covering 70 acres will be installed later this year. MCS intends to use the additional gas from these wells in a second 3 MW facility.

Gas Preprocessing and Energy Plant Equipment
MCS's spent considerable time examining the other landfill gas to electricity projects in an effort to establish a clear design philosophy from which we would build our plant. The result of our investigation was that many of the projects which were encountering problems paid little or no attention to the proper selection of equipment for the application. The

utilization of used outdated equipment for the sake of capital savings is the fundamental reason for project problems at a variety of sites.

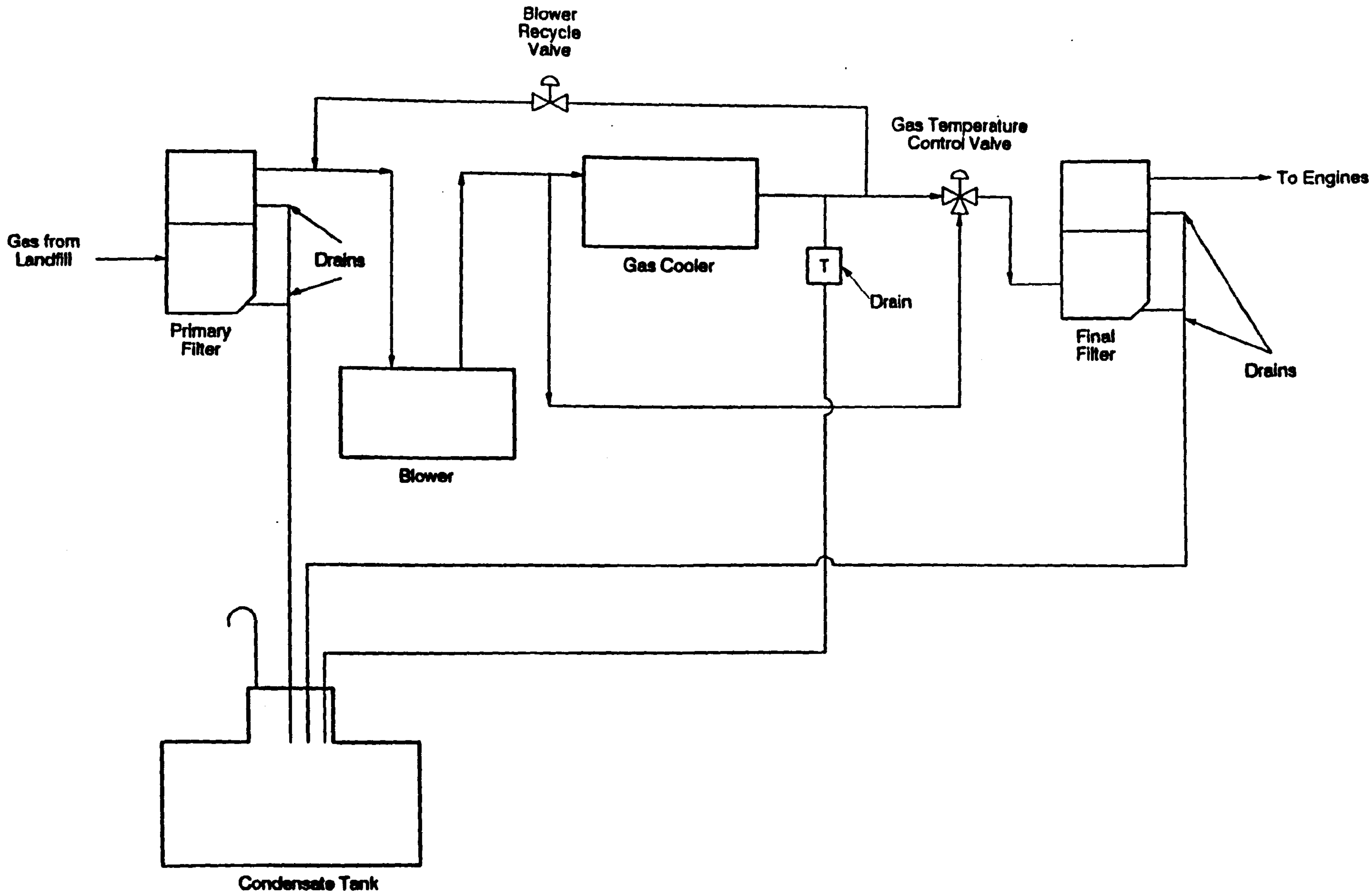
Based on the technical review of the projects visited by MCS coupled with MCS's own operational experience from our 6.6 MW landfill gas recovery project in Michigan, MCS developed a design philosophy for the project. MCS's philosophy was to utilize equipment which was of proven design and which was specifically adapted for use on landfill gas. The following is the culmination of our effort.

Landfill Gas Handling and Preprocessing

The main consideration relative to the gas handling system was to provide the Caterpillar engines gas at a minimum of 2 psi, filtered, and free of liquids. This meant that other than providing good filtering of the gas to remove silica and particulates, that no "processing" of the gas was required. A block diagram describing the system is provided for ease of reference. The gas first enters a primary filter separator which removes all free liquids as well as particulates down to 1.0 microns. The gas then enters the 100 hp blower at approximately 90 °F and is compressed to 6 psig. The gas is then cooled in a forced air gas cooler. Any liquids which may drop out during the cooling process are removed by a trap and collected in a condensate storage tank. The gas then passes through a temperature control valve where its temperature is maintained at a preset level for emissions control. The gas then enters the final gas coalescing filter where any free liquids are once again removed as well as particulates down to 0.3 microns. The gas is then transported by a stainless steel header to each of the four Cat engines. Due to corrosion concerns, all gas piping in the plant is stainless steel.

Engines

The engines selected for the project were the Caterpillar 3516 spark ignited engines. The engines were selected based on their proven operating history on landfill gas and their low gas pressure requirement of only 2 psig. The operating history from sites utilizing the 3516 engines showed that the engines were exceeding Caterpillar's major maintenance intervals for top end overhauls. The engines were getting between 12,000 - 14,000 hours between top end overhauls. The engines were also operating at greater than 90% availability for each of the sites reviewed. The low gas fuel pressure of 2 psig was an additional economic benefit since comparable engines require 30-40 psig fuel pressure which



I-95 Process Flow

creates greater system complexity and greater parasitic losses due to gas compression.

The Caterpillar 3516 has a nameplate rating of 1138 hp/unit with a corresponding output of 800 kW at the generator terminals.

The engines were approved by the local air pollution control district who generally supported the concept of landfill gas utilization.

Performance/Availability

The overall plant performance has been exceptional to date and has far exceeded our initial target of 90% availability. The first two months of operation have produced overall system availabilities of 93% and 98% for January and February. The engines have been exporting between 3050-3100 kW net.

The maintenance on the engines is being performed by MCS according to Cat's recommended maintenance procedures and intervals. Oil change intervals are determined by measuring the TBN level in the oil. Caterpillar recommends changing the oil when the TBN level reaches half of its original level. Oil changes have been performed at between 650-750 hours per engine for the first two months.

Environmental/Emissions

The engines were permitted by the Virginia Department of Air Pollution Control. The engines are permitted for the following limits:

NOX	2.0	grams/hp hr
CO	2.04	grams/hp hr
NMHC	0.461	grams/hp hr

In order to maintain the engines emissions at a constant level, it is necessary to control the combustion air to fuel ratio to the engines at a constant level. By maintaining the air to fuel ratio at a fixed relationship the engines always see the same fuel mixture and therefore produce the same emissions. This is accomplished by maintaining both the air inlet temperature and the gas inlet temperature to the engine at constant preset levels. These preset temperatures are maintained by use of temperature control valves. By controlling these parameters, the air to fuel ratio and therefore the engine emissions remain constant regardless of ambient temperature changes.

Facility Expansion

MCS is planning to expand the facility to produce an additional 3 MW of power. The development work for phase II is currently underway with the second plant scheduled for operations January 1993. Based on the operating history of the initial 15 wells, MCS is very confident that the additional 65 wells planned by the will provide more than enough fuel for the second phase.

Discussion

MCS believes that the formula for success for landfill gas to electricity projects involves two key factors or ingredients.

The first is the proper sizing of the plant relative to the amount of landfill gas the landfill is expected to produce. A major problem for many sites was the oversizing of their facilities relative to the actual landfill gas volumes recovered. MCS has attempted to avoid this pitfall by using actual gas recovery rates from the collection system in lieu of theoretical calculations. The use of theoretical gas projections without any supporting data from actual well tests is very risky.

The second is the selection of the proper equipment and material for the application. This included the Caterpillar 3516 engine, stainless steel gas piping, and high efficiency gas filters. By utilizing these proven types of engineering equipment, it significantly improves the longterm success of the project while reducing annual maintenance costs.

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16. ABSTRACT The report discusses technical, environmental, and other issues associated with using landfill gas as fuel, and presents case studies of projects in the U.S. illustrating some common energy uses. The full report begins by covering basic issues such as gas origin, composition, and means of collection; environmental and regulatory background is presented. Properties of handfill gas as a fuel are reviewed; equipment that can utilize landfill gas is discussed. The report then describes experience with six projects in the U.S. where landfill gas has been used for energy. It also references literature on other landfill gas energy projects of interest. Conclusions regarding uses of landfill gas for energy are presented.

KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Pollution	Decomposition	Pollution Control	13B	11M
Earth Fills	Methane	Stationary Sources	13C	07C
Gases	Carbon Dioxide		07D	07B
Fuels			21D	
Energy			14G	
Refuse				

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