United States
Environmental Protection
Agency

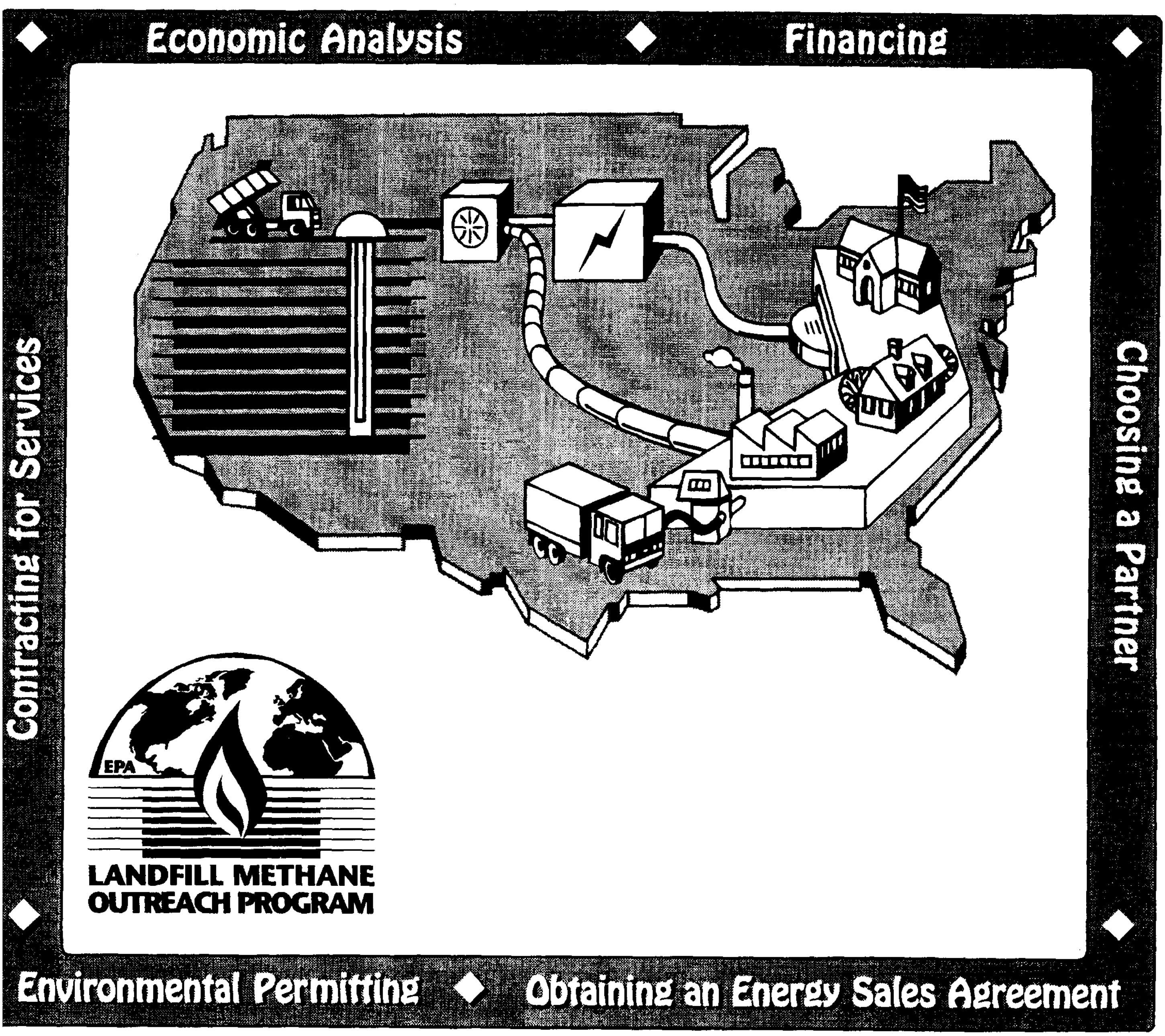
Air and Radiation
(6202J)

EPA 430-B-96-0004
September 1996

EPA

Turning a Liability into an Asset:

A Landfill Gas-to-Energy Project Development Handbook



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Turning a Liability into an Asset:

A Landfill Gas-to-Energy Project Development Handbook

Landfill Methane Outreach Program

U.S. Environmental Protection Agency

September 1996

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ACKNOWLEDGEMENTS

This handbook was prepared with the assistance of numerous individuals. Staff at Boston Pacific provided technical expertise and provided the first draft of most of the document. Staff at ICF Incorporated compiled the chapters, reviewed and edited them, and produced the entire document.

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1. INTRODUCTION

Each person in the United States generates about 4.5 pounds of solid waste per day–almost one ton per year. Most of this waste is deposited in municipal solid waste landfills. As this landfilled waste decomposes (a process that may take 30 years or more), it produces landfill gas. Landfill gas contributes to the formation of smog and poses an explosion hazard if uncontrolled. Furthermore, because landfill gas is about 50 percent methane, it is both a potent greenhouse gas and a valuable source of energy.

The Project Development Process

Part I
Preliminary Assessment of Project Options

- Determining if a Project is Right for Your Landfill
- Determining What Project Configuration is Right for Your Landfill

↓

Part II
Detailed Assessment of Project Economics

- Evaluating Project Economics
- Assessing Financing Options
- Selecting a Project Development Partner
- Winning/Negotiating an Energy Sales Contract
- Securing Project Permits and Approvals
- Contracting for EPC and O&M Services

Substantial opportunities exist across the country to harness this energy resource and turn what would otherwise be a liability into an asset. The purpose of this handbook is to help landfill owners, operators, and others considering landfill gas projects determine whether landfill gas energy recovery is likely to succeed at a particular landfill, and to clarify the steps involved in developing a successful project.

The handbook is organized according to the process of landfill gas project development, as the flowchart on this page illustrates. It contains two major sections: **Part I – Preliminary Assessment of Project Options** provides the landfill owner/operator with basic screening criteria to assess the viability of a landfill energy recovery project and make a preliminary economic comparison of the primary energy recovery options; and **Part II – Detailed Assessment of Project Options** outlines and discusses the major steps involved in development of a landfill gas energy recovery project, from estimating expenses and revenues to constructing and operating the project. The flowchart on this page can be found at the front of each chapter, with the current section and chapter highlighted. Additional information is contained in Appendices A through J of the handbook.

1.1 THE BENEFITS OF LANDFILL GAS ENERGY RECOVERY

Landfill gas energy recovery offers significant environmental, economic, and energy benefits. These benefits are enjoyed by many, including the landfill owner/operator, the project developer, the energy product purchaser and consumer, and the community living near the landfill.

1.1.1 Environmental Benefits

Landfill gas contains volatile organic compounds, which are major contributors to ground-level ozone and which include air toxics. When little is done to control them, these pollutants are continuously released to the atmosphere as waste decomposes. When landfill gas is collected and burned in an energy recovery system, these harmful pollutants are destroyed.

Regulations already require many landfills to collect their landfill gas emissions, and new federal air regulations will soon require additional control. Once the gas is collected, landfill owner/operators have two choices: (1) flare the gas; or (2) produce energy for sale or on-site use. Both options address local air quality and safety concerns, but only energy recovery capitalizes on the energy value of landfill gas, while displacing the use of fossil fuels. Offsetting coal and oil use further reduces emissions of a number of pollutants, including sulfur dioxide, a major contributor to acid rain, as well as the production of ash and scrubber sludge from utilities. Furthermore, landfill gas collection systems operated for energy recovery are often more carefully managed than those designed to flare the gas. This means that more of the gas generated in the landfill may be collected and combusted, with fewer emissions to the atmosphere.

Landfill gas energy recovery also has the potential to significantly reduce the risk of global climate change. Landfill gas is the single largest source of anthropogenic methane emissions in the United States, contributing almost 40 percent of these emissions each year. Reducing methane emissions is critical in the fight against global climate change because each ton of methane emitted into the atmosphere has as much global warming impact as 21 tons of carbon dioxide over a 100 year time period. In addition, methane cycles through the atmosphere about 20 times more quickly than carbon dioxide, which means that stopping methane emissions today can make quick progress toward slowing global climate change.

1.1.2 Economic Benefits

New federal regulations, promulgated in March 1996, require several hundred landfills across the country to collect and combust their landfill gas emissions. Once installation and operation of a collection system is a required cost of doing business, incurring the extra cost of installing an energy recovery system becomes a more attractive investment. Sale or use of landfill gas will often lower the overall cost of compliance and, when site-specific conditions are favorable, the landfill may realize a profit.

More widespread use of landfill gas as an energy resource will also create jobs related to the design, operation, and manufacture of energy recovery systems and lead to advancements in U.S. environmental technology. Local communities will also benefit, in terms of both jobs and revenues, through the development of local energy resources at area landfills.

1.1.3 Energy Benefits

Landfill gas is a local, renewable energy resource. Because landfill gas is generated continuously, it provides a reliable fuel for a range of energy applications, including power generation and direct use. Electric utilities that participate in landfill gas-to-energy projects can benefit by enhancing customer relations, broadening their resource base, and gaining valuable experience in renewable energy development. Landfill gas power projects provide important demand side management benefits, as transmission losses from the point of generation to the point of consumption are negligible. The National Association of Regulatory Utility Commissioners recognized the value of landfill gas as an energy resource when it adopted a resolution in March 1994 "urging regulators to focus their regulatory attention on the landfill gas resources in their States to determine the role that energy from landfill gas can play as an energy resource for utilities and their customers." Industrial facilities, universities, hospitals, and other energy users can benefit by tapping into landfill gas, a low-cost, local fuel source.

1.2 THE EPA LANDFILL METHANE OUTREACH PROGRAM

The EPA Landfill Methane Outreach Program encourages landfill owner/operators to develop landfill gas energy recovery projects wherever it makes economic sense to do so. EPA estimates that over 700 landfills across the United States could install economically viable landfill gas energy recovery systems, yet only about 140 energy recovery facilities are in place. Through the Outreach Program, EPA is working with municipal solid waste landfill owners and operators, states, utilities, industry and other federal agencies to lower the barriers to economic landfill gas energy recovery.

This handbook is one component of the Landfill Methane Outreach strategy for overcoming information barriers to development of energy recovery projects. By providing information that can be used to assess project feasibility and outlining the project development process to landfill owner/operators and others considering energy recovery projects, this handbook can help spur development of successful projects. For more information on the Outreach Program, contact EPA's Hotline at 1-888-STAR-YES.

1.3 HOW TO USE THIS HANDBOOK

If you are a landfill owner/operator – or anyone considering a landfill gas-to-energy project – you can use this handbook to conduct a preliminary assessment of the potential for your landfill to support an energy recovery project. First, review Section 2.1 with the parameters of your landfill in mind. If your landfill meets the basic screening criteria (or has site-specific factors that make it a good candidate for energy recovery), use the information provided in Section 2.2 to develop a rough estimate of available landfill gas. Next, examine the economic comparison in Chapter 3, referring to the landfill gas estimate closest to that for your landfill, and determine which energy recovery option may be most cost-effective. Finally, carefully review Part II of the handbook (Chapters 4 to 10) to gain an understanding of the steps involved in developing an energy recovery project at your landfill. You may want to consult some of the references listed in Appendix H for more detailed information on the gas being generated at your landfill and the collection and energy recovery system you are considering.

This handbook is not meant to be an exhaustive guide to the landfill gas development process, nor is it a technical guide to project design. Once you have decided to pursue a gas-to-energy project, you may want to consult experts with experience in project development as well as technical resources regarding construction, equipment, operation, and other aspects of project design. The Landfill Methane Outreach Program can provide you with a list of landfill gas-to-energy project developers, engineers, equipment manufacturers, financiers, and end-users, and Appendix G contains a listing of organizations that can refer you to additional experts in project design, development, and operation.

PART I

PRELIMINARY ASSESSMENT OF PROJECT OPTIONS

The Project Development Process

Part I **Preliminary Assessment of** **Project Options**
Determining if a Project is Right for Your Landfill
Determining What Project Configuration is Right for Your Landfill

⇓

Part II **Detailed Assessment of** **Project Economics**
Evaluating Project Economics
Assessing Financing Options
Selecting a Project Development Partner
Winning/Negotiating an Energy Sales Contract
Securing Project Permits and Approvals
Contracting for EPC and O&M Services

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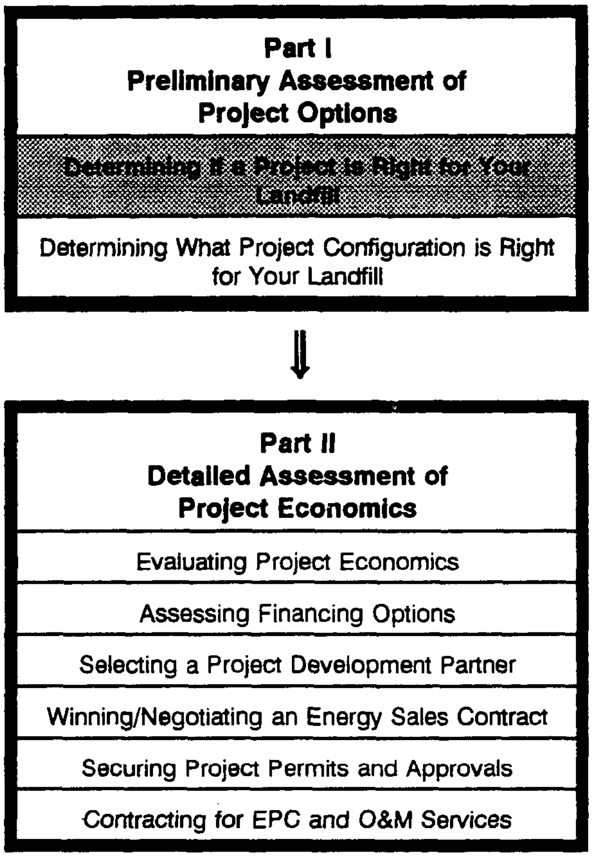
2. Determining If A Project Is Right For Your Landfill

The preliminary assessment of project options includes two major phases. First, the landfill owner/operator must determine whether a project is likely to succeed at his or her landfill. If the landfill meets the criteria for a conventional energy recovery project--or has other characteristics that make it a good energy recovery candidate--the owner/operator next determines what project configuration would be most cost-effective. This chapter describes the steps involved in the first of these phases.

The Project Development Process



Determining if an energy recovery project may be right for a particular landfill is the first phase involved in assessing project options, as shown in the flowchart on this page. This phase involves two steps:

(1) application of basic screening criteria to determine if the landfill has the characteristics that apply generally to successful landfill gas energy recovery projects; and

(2) estimation of the quantity of landfill gas that can be collected, as gas quantity is a critical factor in determining whether landfill gas energy recovery is a viable option.

The approximately 140 landfill gas energy recovery projects operating in the United States exhibit a wide range of landfill characteristics and gas flows, illustrating that many different types of landfills can support successful projects. Nevertheless, there are a few basic criteria that can be used for site screening to determine whether a project is *likely* to succeed at a particular landfill. For example, a large landfill that is still receiving waste will, in general, be an attractive candidate for landfill energy recovery. These and other criteria, and how to apply them, are discussed in Section 2.1.

For landfills that appear to be candidates for energy recovery, estimating landfill gas flows is essential. The amount of gas that can be collected is dependent upon a number of factors, including, among others, the amount of waste in place, the depth of the landfill, the age and status of the landfill, and the amount of rainfall the landfill receives. There are several ways to estimate landfill gas quantity, ranging from "back of the envelope" calculations to sophisticated computer modeling. Not surprisingly, both the degree of certainty that collected gas quantity will match the estimate and the cost of developing the estimate increase along this spectrum. Section 2.2 describes some of the various methods available to estimate the gas generation and collection rate.

If the landfill under consideration for energy recovery already has a gas collection system that is likely to be representative of the area from which gas will be drawn (i.e., not just perimeter wells), the task of estimating gas quantity is essentially complete. The quantity of gas collected with the current system can be used to estimate the amount of gas available for energy recovery.

2.1 Step 1: Basic Screening for Project Potential

The purpose of basic screening is to quickly identify landfills that are good candidates for energy recovery. The questions in Box 2.1 can help guide a landfill owner/operator through the process of evaluating screening criteria, which are identified below. It is likely that the best candidates for energy recovery will have the following characteristics:

- At least one million tons of waste in place;
- Still receiving waste, or closed for not more than a few years; and
- Landfill depth of 40 feet or more.

Landfills that meet these criteria are likely to generate enough landfill gas to support a gas-to-energy project. An industry rule of thumb places the "economically viable" gas generation rate at one million cubic feet per day (1 mmcf/day). However, this figure, like the screening criteria, should be considered only as a guideline – in fact, many landfills that do not meet all of the criteria could support successful energy recovery projects because of important site-specific characteristics. For example, energy recovery projects are currently underway at landfills with as little as 50,000 tons of waste in place, gas flows of 20,000 cf/day and depths of just 10 feet. In addition, about forty percent of existing and planned projects are sited at closed landfills, with about half of these closed during the 1980s [Berenyi and Gould, 1994].

Landfills that already collect their landfill gas, or that will be required to collect the gas, may be attractive candidates for energy recovery, especially if they meet most or all of the other criteria. Once installation and operation of a collection system is a required cost of doing business, the extra cost of energy recovery becomes a more attractive investment. In this situation, energy recovery may be the most cost-effective compliance strategy, even if it does not provide a net profit.

Some additional characteristics may also be indicative of energy recovery potential. These include:

- <u>Climate</u>: Moisture is an important medium for the bacteria that break down the waste. In areas with very low rainfall (i.e., less than 25 inches per year), yearly generation of landfill gas is likely to be relatively low. Therefore, less gas may be available for energy recovery each year at arid landfills (although gas production may continue for a longer period of time than in a wetter environment).

- <u>Waste Type</u>: Methane is generated when organic waste, such as paper and food scraps, decomposes. Therefore, landfills (or cells within landfills) that

Box 2-1 Is a Project Right for Your Landfill?

A. Is your landfill a municipal solid waste landfill?

If not, you may encounter some additional issues in project development due to the presence of hazardous or non-organic waste in the landfill. Stop and consult an energy recovery expert.

B. Add your score for the next 3 questions:

1. How much waste is in your landfill? **Score**

Tons	Score
≥ 3 million	40
1-3 million	30
0.75-1 million	20
< 0.75 million	10

______

2. Is your fill area at least 40 feet deep?
   Yes = 5
   No = 0

+ ______

3. Is your landfill currently open? If yes, answer 3(a). If no, answer 3(b).

   (a) How much waste will be received in the next 10 years?
   For each 500,000 ton, score 5 points. + ______

   (b) If closed < 1 year, enter 0.
   If closed ≥ 1 year, multiply each year since closure by 5, and subtract that amount from the total. – ______

Total your answers to questions 1-3: = ______

C. If your score is:

≥ 30: Your landfill is a good candidate for energy recovery (go to section D).

20-30: Your landfill may be a good candidate for energy recovery, particularly if a factory or other energy user with constant fuel demand is located within a few miles of the landfill (go to Section D).

< 20: Your landfill may not be a good candidate for conventional energy recovery options. However, you may want to consider on-site or alternative uses for the landfill gas.

D. If your landfill is a good candidate, answer the following questions:

1. Are you now collecting gas at your landfill (other than from perimeter wells), or do you plan to do so soon for regulatory or other reasons? If yes, your landfill may be an excellent candidate for energy recovery.

2. (a) Is annual rainfall less than or equal to 25 inches per year?
   (b) Is construction and demolition waste mixed into the municipal waste or is it a large portion of total waste?

If yes to questions D.2(a) or D.2(b), your annual landfill gas production may be lower than otherwise expected. Your landfill may still be a strong candidate, but you may want to lower your estimated gas volumes slightly during project design and evaluation.

contain large proportions of synthetic or slowly-decomposing organic waste, such as plastic and construction/demolition waste, may be less attractive candidates for energy recovery.

- Nearby Energy Use: A smaller landfill may still be a good candidate for energy recovery if there is a use for the gas at or near the landfill. Such landfills should not be discounted without exploration of direct gas use options.

2.2 STEP 2: ESTIMATING GAS QUANTITY

Once the landfill owner/operator has determined that energy recovery may be attractive, the next step is to estimate landfill gas flow. Information from this step is of critical importance in determining the technical specifications of the project and in assessing its economic feasibility. There are a variety of methods, ranging from very basic desktop estimates to actual field tests, as described below. Because both the cost and the reliability of the estimates increases for more detailed methods, it is recommended that the basic estimation approaches be used first, and more detailed methods be used (if warranted) as project assessment progresses.

2.2.1 Methods for Estimating Gas Flow

Three gas flow estimation methods are presented below. The first two are relatively simple approaches that require limited site-specific information. Because landfill characteristics, and therefore gas generation rates, can vary substantially among landfills (even those with the same amount of waste in place), Methods A and B will provide only rough gas flow estimates. When using these methods, the landfill owner/operator should assume that actual gas flows may be 50 percent higher or lower. For example, lower gas flows may occur at landfills located in arid areas (i.e., receiving less than 25 inches of rainfall per year) or at landfills containing large amounts of construction/demolition debris. Method C, in contrast, relies on data from the landfill itself, and should provide more accurate estimates.

Method A: Simple Approximation

A *rough approximation* of landfill gas production can be estimated easily using the amount of waste in place as the only variable. The procedure described below for approximating gas production is derived from the ratio of waste quantity to gas flow observed in the many, often very different, projects in operation. It reflects the *average* landfill that has an energy recovery project, and may not accurately reflect the waste, climate, and other characteristics present at a specific landfill. Therefore, it should be used primarily as a screening tool to determine if a more detailed assessment is warranted (such as can be developed using Method C).

The simple approximation method only requires knowledge of how much waste is in place at the target landfill. Based on their extensive experience at many landfills, industry experts have developed a rule of thumb that landfill gas generation rates range from 0.05 to over 0.20 cubic feet (cf) of gas per pound (lb) of refuse per year, with the average landfill generating 0.10 cf of landfill gas per lb per year [WMNA, 1992; Walsh, 1994].

Using this rule of thumb results in the following equation:

Annual Landfill Gas Generation (cf) = 0.10 cf/lb x 2000 lb/ton x Waste-In-Place (tons)

A sample calculation using this method is shown in Box 2.2. Because the amount of gas generated declines as waste ages in the landfill, the above gas generation estimate is only appropriate for the first year or two of project operation if no new waste is added. As a result, gas generation rates may be on the low end of the range for landfills that have been closed for several years. In addition, the landfill owner/operator should adjust downward his or her rough estimate of gas flows over the life of the project by 2 to 3 percent per year [Wolfe and Maxwell].

Box 2-2 Example Using Simple Approximation Method

For a landfill with one million tons of waste in place, this method yields a rough estimate of 200 million cubic feet of landfill gas per year, or about 550,000 cubic feet per day (cfd). The uncertainty associated with this estimate should be accounted for by adding and subtracting 50 percent, yielding a range for the landfill's gas flow of 275,000 to 825,000 cfd.

Method B: First Order Decay Model

The second approach -- a "First Order Decay Model" -- can be used to account for changing gas generation rates over the life of the landfill of a proposed project. Understanding the rate of gas flow over time is critical to evaluating project economics (see Chapter 5). The first order decay model is more complicated than the rough approximation described above, and requires that the landfill owner/operator know or estimate five variables:

- the average annual waste acceptance rate;
- the number of years the landfill has been open;
- the number of years the landfill has been closed, if applicable;
- the potential of the waste to generate methane; and
- the rate of methane generation from the waste.

The basic first order decay model is as follows:

$$LFG = 2\,L_0 R\,(e^{-kc} - e^{-kt})$$

Where:

LFG	=	Total amount of landfill gas generated in current year (cf)
L_0	=	Total methane generation potential of the waste (cf/lb)
R	=	Average annual waste acceptance rate during active life (lb)
k	=	Rate of methane generation (1/year)
t	=	Time since landfill opened (years)
c	=	Time since landfill closure (years)

The methane generation potential, L_0, represents the total amount of methane that one pound of waste is expected to generate over its lifetime. Thus, it is much higher than the landfill gas generation constant used in Method A to represent landfill gas generation per year. The decay constant, k, represents the rate at which the methane will be released from each pound of waste. If these terms were known with certainty, the first order decay model would predict methane generation relatively accurately; however, the values for L_0 and k are thought to vary widely, and are difficult to estimate accurately for a particular landfill.

The values for L_0 and k are dependent in part on local climatic conditions and waste composition; therefore, a landfill owner/operator may want to consult others in the local area, with similar landfills who have installed gas collection systems to narrow the range of potential values. On March 12, 1996, EPA issued final regulations for the control of landfill gas at new and existing municipal solid waste landfills with design capacities of 2.5 million metric tons or more[1]. Affected landfills model their gas emissions using the first order decay model. The regulations include the following default values (as well as a non-methane organic compound default value of 4000 ppm, which a landfill can replace with site-specific data):

- L_0 = 2.72 cf/lb
- k = 0.05/year

Ranges for L_0 and k values developed by an industry expert are presented in Table 2-1. Note that for different climatic conditions, the L_0 (total amount of landfill gas generated) remains the same, but the k value (rate of landfill gas generation) changes, with dry climates generating gas more slowly.

Table 2-1 Suggested Values for First Order Decay Model Variables

Variable	Range	Suggested Values		
		Wet Climate	Medium Moisture Climate	Dry Climate
L_0 (cf/lb)	0-5	2.25-2.88	2.25-2.88	2.25-2.88
k (1/yr)	0.003-0.4	0.1-0.35	0.05-0.15	0.02-0.10

Source: Landfill Control Technologies, "Landfill Gas System Engineering Design Seminar," 1994.

Because of the uncertainty in estimating L_0 and k, gas flow estimates derived from the first order decay model should also be bracketed by a range of plus or minus 50 percent. Box 2.3 shows a sample calculation using the first order decay model.

Method C: Pump Test

The most accurate method for estimating gas quantity, short of installing a full collection system, is to conduct a pump test. A pump test involves sinking test wells and installing pressure monitoring probes, then measuring the gas collected from the wells under a variety of controlled extraction rates. When conducting a pump test, it is important that the

[1] 61 FR 9905, Tuesday March 12, 1996.

Box 2-3 Example Using First Order Decay Model

For a landfill with the following characteristics:

- open for 25 years;
- still accepting waste; and
- average annual waste acceptance rate of 40,000 tons

The first order decay model would yield a rough estimate of 310 million cubic feet of landfill gas per year, or about 850,000 cfd (using the NSPS k and L_0 values). The uncertainty associated with this estimate should be accounted for by adding and subtracting 50 percent, yielding a range for the landfill's gas flow of 425,000 to 1.3 million cfd.

Note that a landfill with the same amount of waste in place (i.e., one million tons) but a lower waste acceptance rate would have a lower gas flow rate, while a younger landfill that was taking in waste more quickly would have a higher gas flow rate. The choice of different values for k and L_0 in the first order decay model would also yield different gas flow estimates.

test wells are placed to be representative of the waste from which the gas will be eventually drawn, since gas generation rates may vary across the landfill.

A benefit of this method is that the collected gas can be tested for quality, as well as quantity. It should be analyzed for Btu content in addition to hydrocarbon, sulfur, particulate, and nitrogen content. Information obtained from a pump test is important since it is used in the design of the processing and energy recovery system, as well as in obtaining project financing.

The cost to drill test wells can range from $5,000 to $10,000 per well [Smithberger, 1994; Merry, 1994]. However, for budgetary purposes, the total cost of installing a well and extracting gas can be estimated to be approximately $60 per linear foot, with a typical test well being 100 feet deep [Bilgri, 1995]. This estimate includes costs for the well pipe, pipe casing, backfill, and labor. The total number of wells required to accurately predict landfill gas quantity will depend on factors such as landfill size and waste homogeneity.

Other Estimation Methods

Landfill gas energy recovery experts, if consulted by the landfill owner/operator, will almost certainly want to review and verify estimates developed using the above methods, particularly estimates developed with Methods A or B. Each energy recovery expert has his or her own preferred method for estimating landfill gas quantity, and will likely want to use this method to verify estimates prepared using any of the above methods.

2.2.2 Correcting for Collection Efficiency

Before gas generation estimates developed from Methods A or B are used to size a collection/energy recovery system, it is necessary to correct for landfill gas collection efficiency. There are several factors which affect the overall collection efficiency of a landfill gas extraction system, which can vary from about 50 to over 90 percent. The permeability of the landfill's cover layer will determine how much of the landfill gas generated will escape to the atmosphere; however, a portion of the landfill gas will escape through the cover of even the most tightly constructed and controlled collection system. Well spacing and depth, which are determined by economic and other site specific factors, also affect collection efficiency, as can bottom and side liners, leachate and water level, and meteorological conditions.

Collection systems operated for energy recovery may be more efficient than those where the collected gas is not put to productive use because each cubic foot of gas will have a monetary value to the owner/operator. In addition, newer systems may be more efficient than the average system in operation today. Nevertheless, there continues to be economic limits on the tightness of well spacing and other factors that are difficult or impossible to control. Therefore, a reasonable assumption for a newer collection system operated for energy recovery is 75 to 85 percent collection efficiency.

Multiplying the total landfill gas generation estimated by Methods A or B by 75 to 85 percent should yield a reasonable estimate of the landfill gas available for energy recovery. Even the results of Method C may have to be corrected for collection efficiency, since the results of the pump test may not provide an indication of gas flows across the landfill [Kraemer, 1995].

2.2.3 Comparing Your Gas Flow Rate to Existing Projects

For gas flow estimates to be meaningful, the landfill owner/operator must assess whether the available gas flow is sufficient to support an energy recovery project. The average energy recovery facility collects just over 2.5 million cubic feet per day (mmcfd) of landfill gas. However, the ability of a particular gas flow to support an energy recovery project is largely a function of the energy purchaser's or user's needs. Existing project sizes range from 20,000 cfd to over 30 mmcfd, and about one-third of the projects (existing and planned) use less than 1 mmcfd [Berenyi and Gould, 1994]. Two projects spanning much of this range are described in Box 2.4. Information on which project configurations are most cost-effective for a particular gas flow rate is provided in the next section and in Part II of this handbook.

Box 2-4 Energy Recovery at Two Very Different Landfills

Puente Hills Landfill

The Puente Hills Landfill in Whittier, CA, receives 12,500 tons of waste per day, and collects over 30 mmcfd from 400 vertical wells and 50 miles of horizontal collection piping. The Los Angeles County Sanitation Districts, which operates the landfills, uses the landfill gas in three ways:

- in a boiler/steam turbine configuration, located at the landfill, to generate almost 50 MW of power;
- as vehicle fuel, in the form of compressed natural gas;
- as fuel for a boiler at Rio Hondo college, located one mile away

Puente Hills is the largest landfill energy recovery power project in the United States. It has been operational since the early 1980s.

City of Keene, New Hampshire Landfill

The City of Keene is using landfill gas from a 15 acre landfill to power its new recycling/transfer station. The station, located at the City landfill, requires three-phase electricity for its process machinery but the local electric utility's nearest three-phase power line stops several miles away from the site. By instead using gas from the landfill, the City will save more than $200,000 over the expected life of the landfill gas project.

A blower pulls the gas from 10 vertical wells, through simple particle and moisture filters to the (internal combustion) engine-generator set. The recycling/transfer station equipment runs 24 hours per day but is only heavily used during facility working hours. The landfill gas-to-energy system provides peak operating loads at about 180 kW, with the average over a full day at 50 kW. The project was built for a total of $280,000, including the gas collection system, and is expected to cost approximately $25,000 per year in operating costs. [Allan McLane, Vermont Energy Recovery]

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3. Determining What Project Configuration Is Right For Your Landfill

After estimating the quantity of gas available for energy conversion, the landfill owner/operator must decide which conversion option or options make the most sense for the landfill (see Flowchart). Several options may be appropriate. The best choice will depend upon site-specific factors, including the characteristics of the landfill as well as local energy markets. Section 3.1 describes the basic energy conversion options and how a landfill owner/operator can assess which one(s) will be most cost-effective at his or her landfill. Section 3.2 compares the major energy recovery options on a cost basis for three landfill sizes.

The Project Development Process

Part I
Preliminary Assessment of Project Options

Determining if a Project is Right for Your Landfill

Determining What Project Configuration is Right for Your Landfill

⇓

Part II
Detailed Assessment of Project Economics

Evaluating Project Economics

Assessing Financing Options

Selecting a Project Development Partner

Winning/Negotiating an Energy Sales Contract

Securing Project Permits and Approvals

Contracting for EPC and O&M Services

An important consideration in the evaluation of energy conversion options is the availability of federal, state, or local incentives. For example, Section 29 of the Internal Revenue Service Code provides a tax credit for sale of landfill gas to an unrelated party, and the Department of Energy provides an incentive for publicly owned landfill gas facilities that generate electricity. Several states and some localities also provide incentives to landfill projects, such as low cost loan programs or other subsidies. Landfill owner/operators should determine if incentives are available and, if so, how a project must be structured to take advantage of them. (See Chapter 5 for more information on incentives).

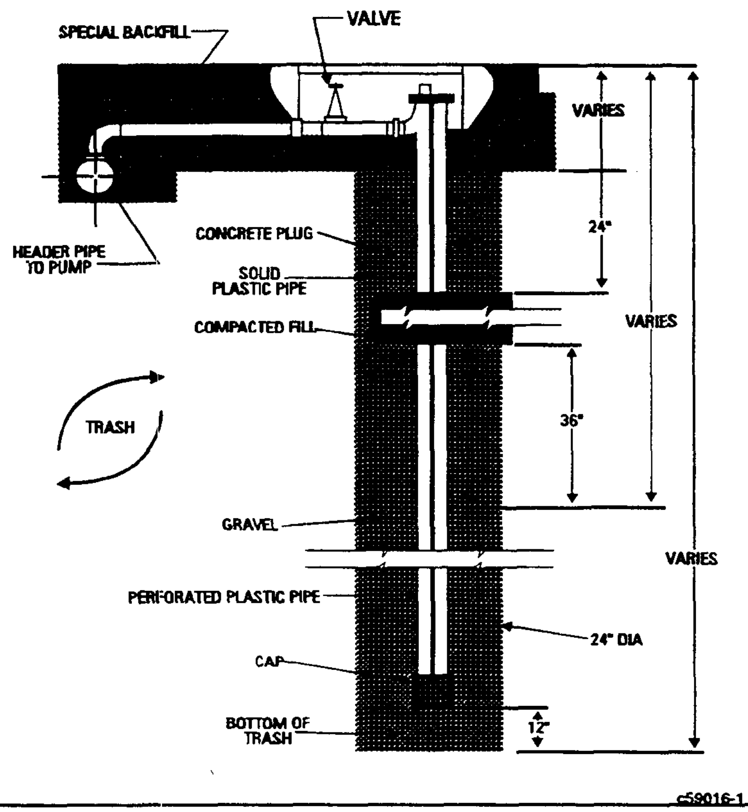
3.1 Options For Using Landfill Gas

Landfill gas can be converted into useable energy in a number of ways, including use as a fuel for internal combustion engines or turbines to produce electricity, direct use of the gas as a boiler fuel, and upgrade to pipeline quality gas, among others. Each of these options entails three basic components: (1) a gas collection system and backup flare; (2) a gas treatment system; and, (3) an energy recovery system. This section provides a brief overview of each component, and outlines the major characteristics of energy recovery systems that determine their applicability at a given site.

3.1.1 Collection System and Flare

Typical landfill gas collection systems have three central components: collection wells; a condensate collection and treatment system; and a compressor. In addition, most landfills with energy recovery systems will have a flare for the combustion of excess gas and for use during equipment down times. Each of these components is described below, followed by a brief discussion of collection system and flare costs. Figure 3.1 illustrates the design of a typical landfill gas extraction well, and Figure 3.2 shows a sample landfill gas extraction site plan.

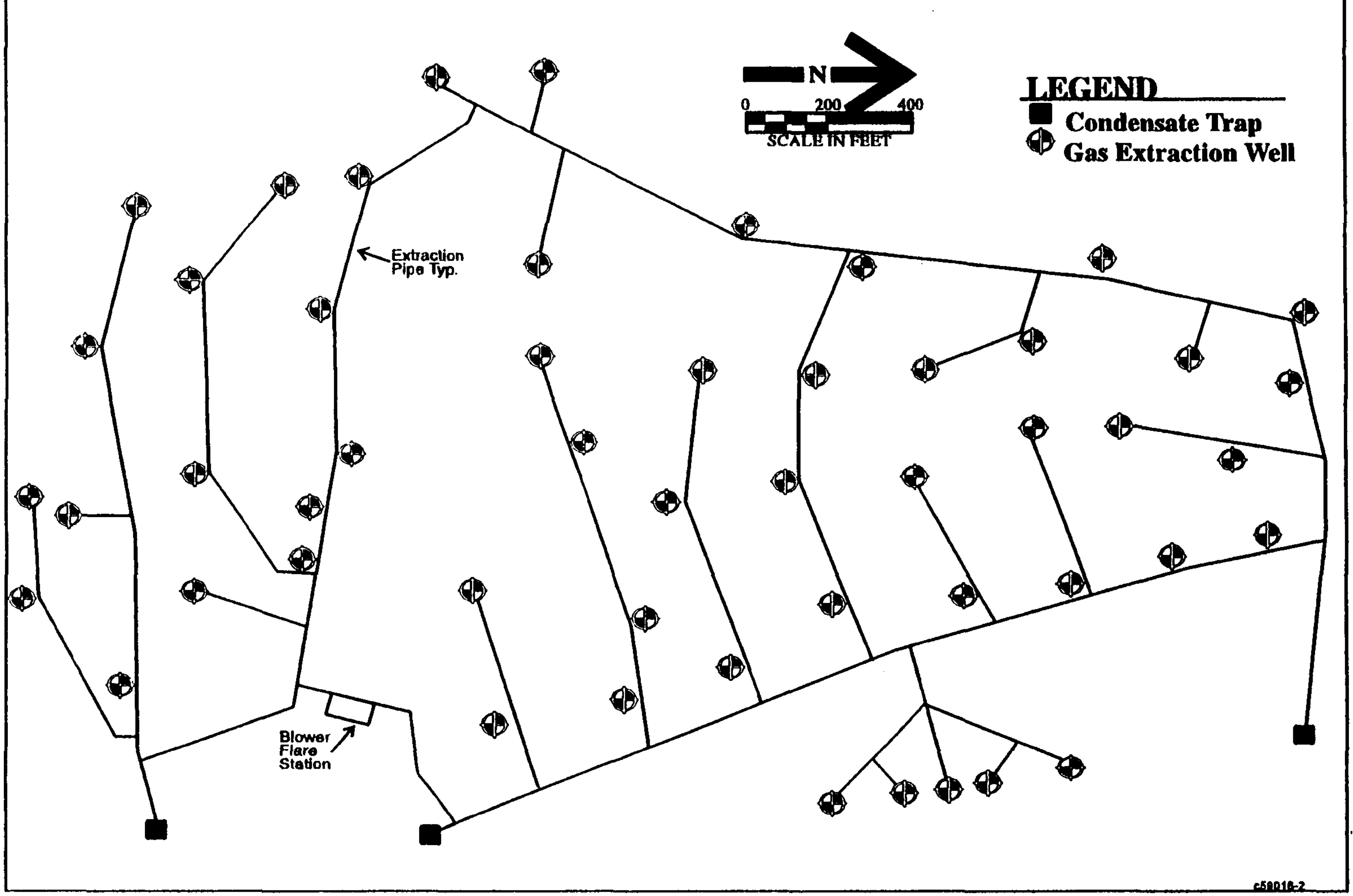
Figure 3-1 Typical Landfill Gas Extraction Well



Gas Collection Wells

Gas collection typically begins after a portion of a landfill (called a cell) is closed. There are two collection system configurations: vertical wells and horizontal trenches. Vertical wells are by far the most common type of well used for gas collection. Trenches may be appropriate for deeper landfills, and may be used in areas of active filling. Regardless of whether wells or trenches are used, each wellhead is connected to lateral piping, which transports the gas to a main collection header. Ideally, the collection system should be designed so that the operator can monitor and adjust the gas flow if necessary.

Figure 3-2 Sample Landfill Gas Extraction Site Plan



Condensate Collection and Treatment

An important part of any gas collection system is the condensate collection and treatment system. Condensate forms when warm gas from the landfill cools as it travels through the collection system. If condensate is not removed, it can block the collection system and disrupt the energy recovery process. Condensate control typically begins in the field collection system, where sloping pipes and headers are used to allow drainage into collecting ("knockout") tanks or traps. These systems are typically augmented by post-collection condensate removal as well. Some of the methods for disposal of condensate are discharge to the public sewer system, on-site treatment, and recirculation to the landfill. The best method for a particular landfill will depend upon the characteristics of the condensate (which may vary depending on site-specific waste constituents), regulatory considerations, and the cost of treatment and disposal.

Blower/Compressor

A blower is necessary to pull the gas from the collection wells into the collection header, and a compressor may be required to compress the gas before it can enter the energy recovery system. The size, type, and number of blowers and compressors needed depends on the gas flow rate and the desired level of compression, which is typically determined by the energy conversion equipment.

Flare

A flare is simply a device for igniting and burning the landfill gas. Flares are considered a component of each energy recovery option because they may be needed during energy recovery system startup and downtime. In addition, it may be most cost-effective to gradually increase the size of the energy recovery system and to flare excess gas between system upgrades (e.g., before addition of another engine). Flare designs include open (or candle) flares and enclosed flares. Enclosed flares are more expensive but may be preferable (or required) because they allow for stack testing and can achieve slightly higher combustion efficiencies. In addition, enclosed flares may reduce noise and light nuisances.

Collection System Costs

Total collection system costs will vary widely, based on a number of site specific factors. If the landfill is deep, collection costs will tend to be higher due to the fact that well depths will need to be increased. Collection costs also increase with the number of wells installed. Table 3-1 presents estimated capital and operating and maintenance costs for collection systems (including flares) at typical landfills with 1, 5, and 10 million metric tons of waste in place. For a landfill with 1 million metric tons of waste, collection system and flare capital costs will likely be approximately $628,000, increasing to about $2.1 million for a 5 million metric ton landfill and $3.6 million for a 10 million metric ton landfill. Annual operation and maintenance costs for the landfill gas collection system may range from $89,000 for the typical 1 million metric ton landfill, increasing to $152,000 for the 5 million metric ton landfill and $218,000 for the 10 million metric ton landfill. [All cost data are in 1994 dollars.]

Flaring costs have been incorporated into the estimated costs of landfill gas collection systems (which are presented in Table 3.1 and in more detail in Chapter 5), since excess gas may need to be flared at any time, even if an energy recovery system is installed. Flare systems typically account for 5 to 15 percent of the capital cost of the entire collection system (i.e., including flares). For a typical landfill with 1 million metric tons of waste in place, flare system capital costs will be approximately $88,000, increasing to about $146,000 for a 5 million metric ton landfill and $205,000 for a 10 million metric ton landfill.[1] Note, however, that flare costs will vary with local air pollution control monitoring requirements and the owner's own safety requirements. For example, if it is necessary to enclose the flare in a building for security or climatic reasons, the proceeding cost figures would increase by approximately $100,000 [Nardelli, 1993].

Annual operation and maintenance costs for flare systems are less than 10 percent of the total collection system costs, and thus range from approximately $8,000 for a 1 million metric ton landfill, increasing to $15,000 for a 5 million metric ton landfill and $21,000 for a 10 million metric ton landfill.

Table 3-1 Summary of Representative Collection System Costs* ($1994)

Landfill Size Waste in Place	Estimated Gas Flow (mcf/day)	Capital Costs ($000)	Annual O&M Costs ($000)
1 million metric tons	642	628	89
5 million metric tons	2,988	2,088	152
10 million metric tons	5,266	3,599	218

* *Collection system costs include flaring costs.*

3.1.2 Gas Treatment Systems

After the landfill gas has been collected, and before it can be used in a conversion process, it must be treated to remove any condensate that is not captured in the knockout tanks, as well as particulates and other impurities. Treatment requirements depend on the end use application. Minimal treatment is required for direct use of gas in boilers, while extensive treatment is necessary to remove CO_2 for injection into a natural gas pipeline. Power production applications typically include a series of filters to remove impurities that could damage engine components and reduce system efficiency.

The cost of gas treatment depends on the gas purity requirements of the end use application; the cost to filter the gas and remove condensate for power production is considerably less than the cost to remove carbon dioxide and other constituents for injection into a natural gas pipeline or for conversion to vehicle fuel. These costs are incorporated into the energy recovery system costs presented in Section 3.1.3 below.

[1] The costs quoted here refer only to the flare system which includes the flare and monitoring equipment. Other items such as the blower and condensate handling system have been reflected in collection system costs.

3.1.3 Energy Recovery System

The goal of a landfill gas-to-energy project is to convert landfill gas into a useful energy form such as electricity, steam, boiler fuel, vehicle fuel, or pipeline quality gas. There are several technologies that can be used to maximize the value of landfill gas when producing these energy forms, the most prevalent of which are:

(1) direct medium-Btu gas use
(2) power production/cogeneration
(3) sale of upgraded pipeline quality gas

The best configuration for a particular landfill will depend upon a number of factors including the existence of an available energy market, project costs, potential revenue sources, and many technical considerations. This section focuses on the technical issues that determine a project's feasibility, and, more specifically, on the technical issues related to direct use and power production, since these are the most common recovery options. Section 3.2 provides more information on choosing among the potential energy recovery technologies.

Option 1: Sale of Medium-Btu Gas

The simplest and often most cost-effective use of landfill gas is as a medium-Btu fuel for boiler or industrial process use (e.g., drying operations, kiln operations, and cement and asphalt production). In these projects, the gas is piped directly to a nearby customer where it is used in new or existing combustion equipment as a replacement or supplementary fuel. Only limited condensate removal and filtration treatment is required, but some modification of existing equipment may be necessary. There are currently about 30 direct use landfill gas projects in operation in the United States, and others are under development [Thorneloe, Pacey, 1994]. Box 3.1 provides specific examples of how landfill gas is being used as a medium-Btu fuel in some of these projects.

Before landfill gas can be used by a customer, a pipeline must first be constructed to access the supply. Pipeline construction costs can range from $250,000 to $500,000 per mile;[2] therefore, proximity to the gas customer is critical for this option. Often, a third party developer is involved in the project who will assume the cost of installing the pipeline.

The customer's gas requirements are also an important consideration when evaluating a sale of medium-Btu gas. Because there is no economical way to store landfill gas, all gas that is recovered must be used as available, or it is essentially lost, along with associated revenue opportunities. Therefore, the ideal gas customer will have a steady, annual gas demand compatible with the landfill's gas flow. In situations where a landfill's gas flow is not enough to support the entire needs of a facility, it may still be used to supply a portion of needs. For example, some facilities have only one piece of equipment (e.g., a main boiler) or set of burners dedicated to burn landfill gas. They also may have equipment that can use landfill gas along with other fuels.

Table 3-2 gives the expected annual gas flows on a MMBtu basis from different sized landfills. While actual gas flows will vary, these numbers may be used as a first step toward determining the compatibility of customer gas requirements and landfill gas output. A general

[2]Pipeline construction costs vary due to terrain differences, right-of-way costs, and other site-specific factors.

Box 3.1 Examples of Direct Use Applications

- The City of Industry, CA has found several uses for landfill gas at its Recreation/Convention Center. Landfill gas is used in boilers to provide hot water for laundry and space heating for the Convention Center. The medium-Btu fuel is also used to heat the Center's swimming pool.
- The Kentucky-Tennessee Clay Company, located in Aiken County, SC, burns landfill gas in its rotary dryer to dry kaolin clay before shipment.
- Ogden Martin Systems, Inc. operates a waste-to-energy plant in Huntsville, AL to supply the steam needs of the U.S. Army's Redstone Arsenal. Landfill gas is used in a supplementary boiler at the waste-to-energy plant to meet the Arsenai's additional steam needs during peak demand periods [Mahin, 1991].
- In Langely, British Columbia, landfill gas is used in a greenhouse to provide heating and CO_2 for growth enhancement [Thorneloe, Pacey, 1994].
- Methane collected from the Acme Landfill in Martinez, CA is used at the Contra Costa Wastewater Treatment Facility.

rule of thumb to use when comparing boiler fuel requirements to landfill gas output is that approximately 8,000 to 10,000 pounds per hour of steam can be generated for every 1 million metric tons of waste in place at a landfill.[3] Using this rule of thumb, it can be estimated that a 5 million metric ton landfill would support the needs of a large facility requiring about 50,000 pounds per hour of steam for process use.

Table 3-2 Landfill Gas Flows Based on Landfill Size

Landfill Size	1 MM Mg	5 MM Mg	10 MM Mg
LFG Output (MMBtu/year)[1]	100,000	490,000	850,000
Steam Flow Potential (lbs/hr)	10,000	45,000	85,000

[1] Assumes a 90% capacity (i.e., availability) factor
Output figures reflect rounding

If an ideal customer is not accessible, then it may be possible to create a steady gas demand by serving multiple customers whose gas requirements are complementary. For example, an asphalt producer's summer gas load could be combined with a municipal building's winter heating load to create a year-round demand for landfill gas.

[3] This rule of thumb is based on steam delivery at 50 psig, saturated.

Equipment modifications or adjustments may be necessary to accommodate the lower Btu value of landfill gas, and the costs of modifications will vary. Costs will be minimal if only boiler burner retuning is required. However, boiler burner retrofits are typically customized, and total installation costs can range from $120,000 for a 10,000 lb/hr boiler to $300,000 for an 80,000 lb/hr boiler [Brown, 1995]. As with pipeline construction costs, a third party project developer may assume the costs of equipment modifications or additions. This was the case when Natural Power, Inc. paid $600,000 to install a new 26,000 lb/hr Cleaver-Brooks boiler to burn landfill gas to serve the steam needs of Ajinomoto USA, Inc., a pharmaceutical plant [Augenstein, Pacey, 1992].

Operation and maintenance (O&M) costs associated with using landfill gas in boilers, kilns, dryers, or other industrial equipment are typically equivalent to O&M costs when using conventional fuels. In general, O&M costs will depend on how well the equipment is maintained and how well the gas collection system is controlled. Some O&M considerations when using landfill gas as a medium-Btu fuel are listed in Box 3.2.

Box 3.2 Considerations When Using Landfill Gas as a Medium-Btu Fuel

It is important to consider the unique aspects of collecting and using landfill gas in equipment such as boilers, kilns, or dryers. Examples of considerations that can help to ensure optimal equipment performance include:

- Moisture content -- Landfill gas generally has three to seven percent moisture when it is collected. Sloped piping and condensate traps must be used to avoid water blockage in landfill gas piping or blowers which can be a cause of system interruptions (e.g., water can trip a gas blower or cause a loss of flame in a boiler).

- Lower flame temperature -- Landfill gas has a lower flame temperature than natural gas, and thus may result in lower superheater temperatures in boilers. Boilers may therefore require larger superheaters to accommodate the use of landfill gas.

- Lower Btu value -- The heating value of landfill gas can be reduced if collection wells draw in large amounts of air or if breaks in the collection piping occur. Good design and operating practices can prevent such problems [Eppich and Cosulich, 1993].

Option 2: Power Generation

The most prevalent use for landfill gas is as a fuel for power generation, with the electricity sold to a utility and/or a nearby power customer. Power generation is advantageous because it produces a valuable end product--electricity--from waste gas. Facilities that use landfill gas to generate electricity can qualify as a "small power producer" under the Public Utilities Regulatory Policy Act (PURPA), which requires electric utilities to purchase the output from such facilities at the utility's avoided cost. The electricity can in some cases be used on-site to displace purchased electricity or be sold to a nearby electricity user (e.g., municipality, industrial).

Cogeneration is an alternative to producing electricity only. Cogeneration systems produce electricity and thermal energy (i.e., steam, hot water) from one fuel source. Whereas the thermal efficiencies of electricity-only generation range from 20% to 50%, cogeneration systems can achieve substantially higher efficiencies by putting to use the "waste" heat that is a by-product of most power generation cycles. Thermal energy cogenerated by landfill gas projects can be used on-site for heating, cooling, and/or process needs, or piped to a nearby industrial or commercial user to provide a second revenue stream to the project.

Several good conversion technologies exist for generating power -- internal combustion engines, combustion turbines, and boiler/steam turbines -- each of which is described below. Box 3.3 highlights important aspects of each option. In the future, other technologies, such as fuel cells, may also become commercially available. Box 3.4 provides some discussion on the design considerations when sizing a landfill gas power project.

Internal Combustion Engine

The reciprocating internal combustion (IC) engine is the most commonly used conversion technology in landfill gas applications; almost 80 percent of all existing landfill gas projects use them [Thorneloe, 1992]. The reason for such widespread use is their relatively low cost, high efficiency, and good size match with the gas output of many landfills. In the past, the general rule of thumb has been that IC engines have generally been used at sites where gas quantity is capable of producing 1 to 3 MW [Thorneloe, 1992], or where landfill gas flows are approximately 625,000 to 2 million cubic feet per day at 450 Btu per cubic foot [Jansen, 1992].

IC engines are relatively efficient at converting landfill gas into electricity. IC engines running on landfill gas are capable of achieving efficiencies in the range of 25 to 35 percent. Historically, these engines have been about 5 to 15 percent less efficient when using landfill gas compared with natural gas operation, although the newest engine designs now sacrifice less than 5 percent efficiency when landfill gas is used [Augenstein, 1995]. Efficiencies increase further in cogeneration applications where waste heat is recovered from the engine cooling system to make hot water, or from the engine exhaust to make low pressure steam. IC engines adapted for landfill gas applications are available in a range of sizes, and can be added incrementally as landfill gas generation increases in a landfill.[4]

Environmental permitting may be an issue for some IC engine projects. IC engines typically have higher rates of nitrogen oxide (NO_x) emissions than other conversion technologies, so in some areas it may be difficult to obtain permits for a project using several IC engines. To address this problem, engine manufacturers are developing engines that produce less NO_x using improved combustion and other air emission control features. These advances should give plant designers more flexibility to use IC engines on large projects.

The installed capital costs for landfill gas energy recovery projects using IC engines are estimated to range from about $1,100 per net kW output to $1,300 per net kW output (1996 on-line date). These costs are indicative of power projects at landfills ranging in size from 1 million metric tons to 10 million metric tons of waste in place, and the costs include the engine, auxiliary equipment, interconnections, gas compressor, construction, engineering,

[4]The most commonly used IC engines for landfill gas applications are rated at about 800 and 3,000 kW.

Box 3.3 Comparison of Electricity Generation Technologies

	IC Engines	Combustion Turbines	Steam Turbine/Boiler
Typical Project Size (MW)	≥ 1	> 3	> 8
Landfill Gas Requirements (mcf/day)	≥ 625	> 2,000	> 5,000
Typical Capital Costs ($/kW)	1,100 - 1,300	1,200 - 1,700	2,000 - 2,500
Typical O&M Costs (¢/kWh)	1.8	1.3 - 1.6	1.0 - 2.0
Electric Efficiency (%)	25 - 35	20 - 28 (CT) 26 - 40 (CCCT)	20 - 31
Cogeneration Potential	Low	Medium	High
Compression Requirements (Input Gas Pressure (psig))	Low (2 - 35)	High (165+)	Low (2 - 5)
Advantages	• Low cost • High efficiency • Most common technology	• Corrosion resistant • Low O&M costs • Small physical size • Low NO_x emissions	• Corrosion resistant • Can handle gas composition and flow variations
Disadvantages	• Problems due to particulate matter buildup • Corrosion of engine parts and catalysts • High NO_x emissions	• Inefficient at part load • High parasitic loads, due to high gas compression requirements	• Inefficient at smaller sizes • Requires large amounts of clean water • High capital costs

* All costs reflect a 1996 on-line date.

Box 3.4 Design Considerations When Sizing Power Projects

Determining the optimum size for a landfill gas power project requires a careful balance between maximizing electricity production and landfill gas use, and minimizing the risk of insufficient gas supplies in later years. The challenge arises because landfill gas production rates change over time. Gas generation may be increasing at an open landfill or decreasing at a closed landfill. System designers must also consider factors such as current and future electricity payments, equipment costs, and any penalties for shortfalls in electricity output.

The optimum design and operating scenario for a particular landfill gas project is likely to fall somewhere between two general scenarios: (1) minimum gas flow design; and (2) maximum gas flow design. However, a third design scenario--a modular approach--may be used at landfills where gas flow rates are expected to change substantially over time.

(1) Minimum Gas Flow Design. In this scenario, the electric generation equipment is sized based on the minimum expected gas flows over the life of the project. This ensures that the fuel supply (i.e., landfill gas) is seldom or never limited, and the electric generation system always runs at or near its maximum availability. This is a more conservative design, which puts a premium on constant and reliable electrical output over the project life. The disadvantage of this design is that some landfill gas will go unused in years when gas is plentiful; a lost opportunity to generate electricity and earn revenues. This may be a good design choice when project economics are robust and substantial contract penalties exist for shortfalls in electrical deliveries from the project. Capacity factors for this type of project are determined mainly by the generating equipment outage rates, which are approximately 6% to 10% for IC engine systems and 4% to 6% for combustion turbine-based systems.

(2) Maximum Gas Flow Design. In this scenario, the electric generating equipment is sized based on maximum gas flows over the life of the project. Landfill gas usage and electrical output are generally maximized, but there may be occasions when there is insufficient landfill gas supply to run the generating equipment at its rated capacity. This is a more aggressive design which puts a premium on full utilization of the landfill gas, and it has the advantage of higher electrical generating capacity, revenues, and landfill gas utilization than the first scenario. However, the disadvantages are that the project may suffer from periods when electrical output is below the rated capacity because of intermittent gas supply shortages or declining landfill production. This is an acceptable design if maximizing early-year revenues is critical, the power purchase contract is short-term, shortfall penalties are nonexistent, and/or alternate or augmented fuel supplies exist. Capacity factors for this type of project are determined by generating equipment outage rates and expected periods when fuel supply is limited. Part-load generating efficiency is a consideration in this type of project; IC engines and fuel cells generally exhibit better part-load performance (e.g., efficiency, wear) than CT-based systems.

(3) Changing Gas Flow Design. In this scenario, a series of smaller electric generating units is installed (or removed) over time as gas flow rate increases (or decreases). This modular approach helps ensure that landfill gas output is properly matched to equipment size, even when gas flow rates change. This approach has the dual benefit of maximizing gas use and electric output over time. However, a modular approach may also produce higher installation costs and lower efficiencies than other approaches. If gas flow is decreasing over time, designers must consider what to do with units that are no longer useful.

and soft costs. (Chapter 5 provides more detail on technology costs.) The costs associated with the landfill gas collection system are not included in these cost estimates.

Combustion Turbine

Combustion turbines (CTs) are typically used in medium to large landfill gas projects, where landfill gas volumes are sufficient to generate a minimum of 3 to 4 MW (i.e., where gas flows exceed approximately 2 million cfd). This technology is competitive in larger landfill gas electric generation projects because, unlike most IC engine systems, CT systems have significant economies of scale. The cost per kW of generating capacity drops as CT size increases, and the electric generation efficiency generally improves as well.

Simple-cycle CTs applicable to landfill gas projects typically achieve efficiencies of 20 to 28 percent at full load; however, these efficiencies drop substantially when the unit is running at partial load. Combined-cycle configurations, which recover the waste heat in the CT exhaust to make additional electricity, can boost the system efficiency up to approximately 40 percent, but this configuration is also less efficient at partial load [EPA, 1993]. One of the primary disadvantages of CTs is that they require high gas compression (165 pounds per square inch (psig) or greater), causing high parasitic load loss. This means that more of the plant's power is required to run the compression system, as compared to other generator options [WMNA, 1992]. An advantage is that turbines are much more resistant to corrosion damage than IC engines and have lower NO_x emission rates. In addition, combustion turbines are relatively compact and have low operations and maintenance costs in comparison to IC engines.

The installed capital costs for landfill gas energy recovery projects using simple cycle CTs are estimated to range from about $1,200 per net kW output to $1,700 per net kW output (1996 on-line date), for power projects at landfills ranging in size from 1 million metric tons to 10 million metric tons of waste in place, respectively. The costs include the CT, auxiliary equipment, interconnections, gas compressor, construction, engineering, and soft costs. (Chapter 5 provides more detail on technology costs.) The costs associated with the landfill gas collection system are not included in these cost estimates. For combined-cycle systems installed at landfills ranging in size from 5 million metric tons to 10 million metric tons of waste in place, the installed capital costs range from about $1,400 per net kW output to $1,700 per net kW output (1996 on-line date). A combined-cycle system is not likely to be economically competitive at landfills with less than about 5 million metric tons of waste in place.

Boiler/Steam Turbine

The boiler/steam turbine configuration is the least used of the three landfill gas power conversion technologies. It is applicable mainly in very large landfill gas projects, where gas flows support systems of at least 8 to 9 MW (i.e., where gas flows are greater than 5 mmcfd) [EPA, 1993]. The boiler/steam turbine consists of a conventional gas/liquid fuel boiler, usually a packaged unit, and a steam turbine generator that produces electricity. This technology usually requires a complete water treatment and cooling cycle, plus an ample source of process and cooling water. Boiler/steam turbine systems have a significantly higher cost per kW than either IC engines or CT systems, so only the largest landfill gas projects can afford to use this technology.

Fuel Cell

Fuel cells that run on landfill gas show great promise for power generation because of their modularity, small capacity, high efficiency, quiet operation, and low environmental impact. It is for these reasons that fuel cells may be an ideal technology for generating power from landfill gas, once they have been fully demonstrated. While a few fuel cells running on natural gas are in commercial operation, fuel cells capable of using landfill gas are still in the development/demonstration phase. The biggest hurdle has been development of a feasible system for cleaning landfill gas prior to use in the fuel cell.

Fuel cells create energy by combining hydrogen (obtained from a fuel source such as landfill gas) and oxygen (supplied from the air) in an electrochemical reaction. Electricity is produced continuously, as long as there is a supply of fuel and air, at high efficiencies (e.g., 50 percent or more). There are three types of fuel cells suitable for power generation: phosphoric acid fuel cells; molten carbonate fuel cells; and solid oxide fuel cells. Phosphoric acid fuel cells (PAFC), which use hydrogen gas or reformed methanol as fuel sources, are the closest to commercialization for a landfill gas application. A 200-kW PAFC plant has been tested by the EPA at the Penrose Landfill in Sun Valley, California [Swanekamp, 1995].[5] Northeast Utilities installed the test unit at the Flanders Road Landfill in Groton, Connecticut in late 1995, and operation at the site began in June, 1996. Connecticut Light & Power, a subsidiary of Northeast Utilities, is operating and maintaining the test unit, and using 140 kW of the power it produces. In addition, the Department of Energy is working to demonstrate molten carbonate fuel cell technology for landfill gas applications.

Option 3: Upgrade to High-Btu Gas

A third project option is to upgrade the landfill gas to a high-Btu product for injection into a natural gas pipeline. Because of the relatively high capital cost of this option, it may be cost-effective only for those landfills with substantial recoverable gas (i.e., at least 4 million cfd [Maxwell, 1990]). This application requires relatively extensive treatment of the gas to remove CO_2 and impurities. In addition, gas companies require that gas injections into their pipeline systems conform with strict quality specifications, which can impose additional quality control and compression requirements. However, this may be an attractive option for some landfill owners, since it is possible to utilize all gas that is recovered.

Upgraded gas will require significant compression in order to conform with the pipeline pressure at the interconnect point. High pressure lines may require pressures of as much as 300 to 500 pounds per square inch (psig), while low and medium-pressure lines may require 10 to 30 psig.

Option 4: Alternative Uses

Other landfill gas utilization options include on-site use of the gas (which may be particularly appropriate for small landfills), heating greenhouses, producing carbon dioxide and other niche applications, or use as vehicle fuel, such as compressed natural gas and methanol. On-site and niche applications are in limited use. Vehicle fuel uses are currently in the commercialization phase, with only a few projects in place (Box 3.5 highlights two of these projects). These and other emerging applications must be evaluated on a case-by-case basis. Their likelihood of success at a particular landfill depends on site-specific factors such as the needs of the landfill, its size, and the quality of the gas. Regulatory developments, the goals of the owner/operator (e.g., an alternative, low emissions fuel source may be attractive for a municipality's fleet), and the needs of potential customers are also important. Because these applications are not fully commercial, they are not discussed extensively in this handbook.

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[5] In July, 1996, Ron Spiegel of EPA's Office of Research and Development, was named a finalist for the 1996 Discover Magazine awards for his work in applying fuel cell technology to landfill gas.

Box 3.5 Landfill Gas as a Vehicle Fuel

CNG Application

The Los Angeles County Sanitation District's Puente Hills Landfill has succeeded in turning landfill gas into a clean vehicle fuel. The Sanitation District has installed a compressed landfill gas fueling station on-site and has converted a Sierra pickup truck, a Hercules water truck and the first of four garbage trucks to run on the compressed gas. This project has eliminated the need to flare excess gas from the landfill, and has reduced vehicle emissions at the same time.

Methanol Production

Using $500,000 in funding from the South Coast Air Quality Management District of California, TeraMeth Industries, Inc. modified its proprietary technology to produce Grade A methanol from landfill gas. Methanol (the critical ingredient in MTBE for federal and state reformulated gasoline requirements) is produced by first creating a synthesis gas which is then fed into a catalyst.

TeraMeth's California facility will produce 16,667 gallons per day of methanol when it begins operation in 1997 [Bonny, 1996].

3.2 Choosing an Energy Recovery Option

The primary factor in choosing the right project configuration for a given landfill is the cost of the energy recovered. In general, sale of medium-Btu gas to a nearby customer, which requires minimal gas processing and typically is tied to a retail gas rate rather than an electric utility buyback rate, is the simplest and most cost-effective option. If a suitable customer is nearby and willing to purchase the gas, this option should be thoroughly examined. For many landfills, however, power production is and will continue to be the best available option. This section therefore focuses on the power production options.

At the foundation of any cost estimation is the expected amount of landfill gas that will be available for energy recovery. For initial assessments, an estimate of landfill gas quantity is all that is needed to estimate power potential. Assumptions regarding the Btu value of the gas, the efficiency of the generator, and the amount of downtime can then be used to convert the gas volume into power potential, as shown in Box 3.6.

This section compares the power production options on a unit cost basis for typical landfills with 1, 5, and 10 million tons of waste in place.[6] In addition to the landfill size and its associated gas production, a number of other factors are also important to project costs. These include: project scope (i.e., whether both a collection system and an energy recovery

[6] The amount of landfill gas associated with these landfill sizes was estimated using an EPA model that falls within the range of methods A and B presented in Chapter 2.

Box 3.6 Converting Gas Flow Rates into Power Potential

1) Estimate the *Gross Power Generation Potential.* This is the installed power generation capacity that the gas flow can support. It does not account for parasitic loads from auxiliary systems and equipment, or for system down time. *Gross Power Generation Potential* is estimated using the following formula:

$$kW = \text{Landfill Gas Flow (cf/d)} \times \text{Energy Content (Btu/cf)} \times 1/\text{Heat Rate (kWh/Btu)} \times 1\text{d}/24\text{hr}$$

where:

- Landfill Gas Flow is the net quantity of landfill gas per day that is captured by the collection system, processed, and delivered to the power generation equipment (usually 75% to 85% of the total gas produced in the landfill)
- Energy Content of landfill gas is approximately 500 Btu per cubic foot
- Example Heat Rates are:
  12,000 Btu/kWh for IC Engines and combustion turbines (above 5 MW); and
  8,500 Btu/kWh for combined-cycle combustion turbines.

2) Estimate the *Net Power Generation Potential.* This is the Gross Power Generation Potential less parasitic loads from compressors and other auxiliary equipment. Parasitic loads are estimated to range from 2% for IC engines to 6% or higher for combustion turbines.

3) Estimate the *Annual Capacity Factor.* This is the share of hours in a year that the power generating equipment is producing electricity at its rated capacity. Typical Annual Capacity Factors for landfill gas projects range between 80% and 95% and are based upon generator outage rates (4% to 10% of annual hours), landfill gas availability, and plant design. The assumed Annual Capacity Factor in the equation found in 4) is 90%. (See Table 3-2).

4) Estimate the *Annual Electricity Generated.* This is the amount of electricity generated per year, measured in kWh, taking into account likely energy recovery equipment downtime. It is calculated by multiplying the Net Power Generation Potential by the number of operational hours in a year. Annual operational hours are estimated as the number of hours in a year multiplied by the Annual Capacity Factor. Thus:

$$\text{Annual Electricity Generated (kWh)} = \text{Net Power Generation Potential (kW)} \times 24\ \text{hr/day} \times 365\ \text{days/yr} \times 90\%$$

system are required or only an energy recovery system); financing method; and available incentives to encourage landfill gas energy recovery. Each of these factors is discussed briefly below.

- **Project Scope:** Project scope depends upon the extent of landfill gas collection activities already underway (or planned) at the landfill, and it can have a significant impact on project costs. There are two typical landfill project scopes:

  - Total Project: refers to those projects at landfills with no current gas collection or energy recovery. For these projects, the entire project (including both gas collection and energy recovery systems) must be installed and the full costs must be recovered through the revenues from energy sales; and

  - Energy Recovery Project: refers to projects at landfills where gas collection systems have already been (or will soon be) installed. At these landfills, the costs associated with the collection system are sunk costs, and the only costs that need to be taken into consideration for the economic analysis are those associated with the additional equipment (i.e., the energy conversion system).

- **Financing Method:** As discussed in Chapter 6, there are many different financing methods available for landfill projects. The most common financing methods are private equity financing, "project finance" using a combination of debt and equity, and municipal bond finance, where public organizations issue bonds to raise project debt. The choice of financing method can have a significant impact on project costs; in general, municipal bond financing is much less expensive than financing with commercial debt and/or equity.

- **Available Incentives:** Because of the importance of encouraging landfill gas energy recovery, a number of federal, state and local incentives are available to these projects. The most important incentives are likely to be the IRS Section 29 tax credit, which may be available to private project developers, and the Department of Energy's Renewable Energy Production Incentive (REPI), which is available to public project developers. Both of these incentives can significantly improve project economics. The Section 29 tax credit is currently worth about ¢0.9 to ¢1.3/kWh, depending upon the efficiency of the generating equipment. The REPI is worth up to ¢1.5/kWh.

The cost per kilowatt hour for each power generation option -- IC engine, combustion turbine, or steam turbine -- will vary with the size of the landfill and these other factors, as shown in Table 3-3. Table 3-3 can be used to estimate the likely costs of a power generation project in the following way:

1. Determine whether it will be necessary to install both a gas collection system and an energy recovery system at the landfill, or only an energy recovery system. If both systems are required, examine the "Total Project" entries; if only an energy system is required, examine the "Energy Recovery Project Only" entries.

2. Determine whether municipal or private financing will be used. If the landfill is owned by a municipality, it is possible that municipal bonds can be issued to cover costs; otherwise, private financing will likely be required.

3. Determine whether financial incentives may be available. If the project will be developed by a private developer and the gas sold to a third-party, Section 29 tax credits may be available. Public or non-profit landfill owners or developers, in contrast, may be eligible for the REPI program.

4. Determine the likely project size based on the amount of waste in place at the landfill.

Making these four decisions will enable a landfill owner/operator to determine likely power production costs for a range of generating technologies. In many cases, the lowest cost generating option will be selected. In some cases, however, it may be necessary to select a higher cost option due to other important considerations. IC engines may not be the best technology choice in certain areas, for example, due to their higher NOx emissions as compared to turbines.

As Table 3-3 illustrates, the estimated costs of power production can vary substantially depending on the factors presented above. At the high end, costs for a "Total Project" financed with private finance and unable to obtain any incentives could range from ¢7.4 to ¢7.9 per kWh for a 1 million ton landfill. The availability of municipal financing could reduce these costs by about ¢0.8 per kWh and developing an ""Energy Recovery System Only"" project could save approximately ¢2.5 per kWh. The lowest cost scenario--an ""Energy Recovery System Only"" project built with municipal financing and obtaining available incentives--has estimated costs ranging from ¢2.8 to ¢4.0 per kWh, which is less than half of the high cost case.

The same phenomenon is observed at the larger 5 and 10 million ton landfills. On the high end, "Total Project" costs at a 5 million ton landfill are estimated to range from ¢6.0 to ¢6.5 per kWh. This same project, implemented with municipal financing and available incentives, however, could cost only ¢4.0 to ¢4.3 per kWh. If the landfill already has (or plans to install) a gas collection system, the "Energy Recovery System Only" costs could be as low as ¢2.7 per kWh.

At the 10 million ton landfill, high end "Total Project" costs of ¢5.6 to ¢5.9 per kWh drop to ¢2.3 to ¢2.9 per kWh for an "Energy Recovery System Only" project with municipal bond financing and incentives. Interestingly, at this size the CT is more cost-effective than IC engine. In addition, the effects of economies of scale are evident, as the costs of similar projects at a 10 million ton landfill are an average of 20 to 30 percent lower than the 1 million ton landfill and 5 to 15 percent lower than the 5 million ton landfill.

It is important to recognize that the cost estimates presented here are rough estimates developed using assumptions related to "typical" landfills. Conditions at any particular site could be quite different and these site-specific conditions must be fully accounted for when developing detailed cost estimates for specific projects.

Part II of this handbook discusses in more detail the major steps involved in the development of a landfill gas energy recovery project, from estimating expenses and revenues to constructing and operating the project. In addition, EPA is developing a simple financial model that landfill owner/operators and others can use to estimate project costs and run sensitivity analyses. To obtain a copy of this model when it becomes available, call the EPA Landfill Methane Outreach Program Hotline at 1-888-STAR-YES.

Table 3-3 Estimated 1996 Costs of Electricity

	IC Engine		Combustion Turbine		Combined Cycle CT	
	Municipal Financing	Private Financing	Municipal Financing	Private Financing	Municipal Financing	Private Financing
Total Project without Financial Incentives (¢/kWh)						
1 Million	6.7	7.4	7.0	7.9	NA	NA
5 Million	5.5	6.0	5.6	6.2	5.8	6.5
10 Million	5.2	5.8	5.0	5.6	5.3	5.9
Total Project with Financial Incentives (¢/kWh)						
1 Million	5.2	6.1	5.5	6.6	NA	NA
5 Million	4.0	4.7	4.1	4.9	4.3	5.6
10 Million	3.7	4.5	3.5	4.3	3.8	5.0
Energy Recovery System Only *without* Financial Incentives (¢/kWh)						
1 Million	4.3	4.8	4.7	5.3	N.A.	N.A.
5 Million	4.2	4.6	4.2	4.7	4.7	5.3
10 Million	4.1	4.5	3.8	4.2	4.3	4.8
Energy Recovery System Only *with* Financial Incentives (¢/kWh)						
1 Million	2.8	3.5	3.2	4.0	NA	NA
5 Million	2.7	3.3	2.7	3.4	3.4	4.4
10 Million	2.6	3.2	2.3	2.9	2.9	3.9

NA: Technology was not evaluated at this landfill size.

The municipal finance scenarios were calculated using a capital charge rate of 0.111, which is based on financing with tax-exempt municipal bonds at an interest rate of 6.5%.

The incentive under the municipal finance plan scenario is the proposed federal REPI subsidy of 1.5 cents/kwh.

The private finance scenarios were calculated using a capital charge rate of 0.136, which is based on a project finance structure using: 80% debt, 20% equity; 9% interest in debt; 15% return on equity; 10 year depreciation.

Incentives under the project finance scenarios are IRS Section 29 Tax Credits, which are estimated to be worth their full value of $0.979/MMBtu in 1994, or 0.9 to 1.3 cents/kwh in 1996. In some cases, only a percentage of the tax credit value can be applied to a project if the credits are transferred between parties. For example, if 60% of the tax credit value can be applied to the project, then 1996 electricity costs would increase by 0.4 to 0.5 cents/kwh.

All scenarios include a royalty payment of 0.5 cents/kwh.

PART II

DETAILED ASSESSMENT OF PROJECT ECONOMICS

The Project Development Process

Part I
Preliminary Assessment of Project Options

- Determining if a Project is Right for Your Landfill
- Determining What Project Configuration is Right for Your Landfill

⇓

Part II
Detailed Assessment of Project Economics

- Evaluating Project Economics
- Assessing Financing Options
- Selecting a Project Development Partner
- Winning/Negotiating an Energy Sales Contract
- Securing Project Permits and Approvals
- Contracting for EPC and O&M Services

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4. Introduction To Part II: Detailed Assessment Of Project Options

Once the landfill owner/operator has determined that an energy recovery project is right for a particular landfill, and has made a preliminary assessment of the project options, he or she must conduct a more detailed assessment of the options, considering cost, financing, project structure, and other aspects of project development. This section contains information on each step in the assessment of project options, organized into the following chapters:

Chapter 5: Evaluating Project Economics

Chapter 6: Assessing Financing Options

Chapter 7: Selecting a Project Development Partner

Chapter 8: Winning/Negotiating an Energy Sales Contract

Chapter 9: Obtaining Project Permits and Approvals

Chapter 10: Contracting for EPC and O&M Services

Each chapter contains the basic information--illustrated throughout with examples--needed to conduct one step in the project assessment process. By reviewing each chapter with a particular landfill in mind, an owner/operator can develop a solid understanding of the most cost-effective and appropriate options and project structure.

While this handbook provides valuable information to assist the owner/operator in evaluating choices and proposals, it does not serve as a technical guide to project development. The owner/operator may wish to consult a landfill gas energy recovery expert before beginning the development process.

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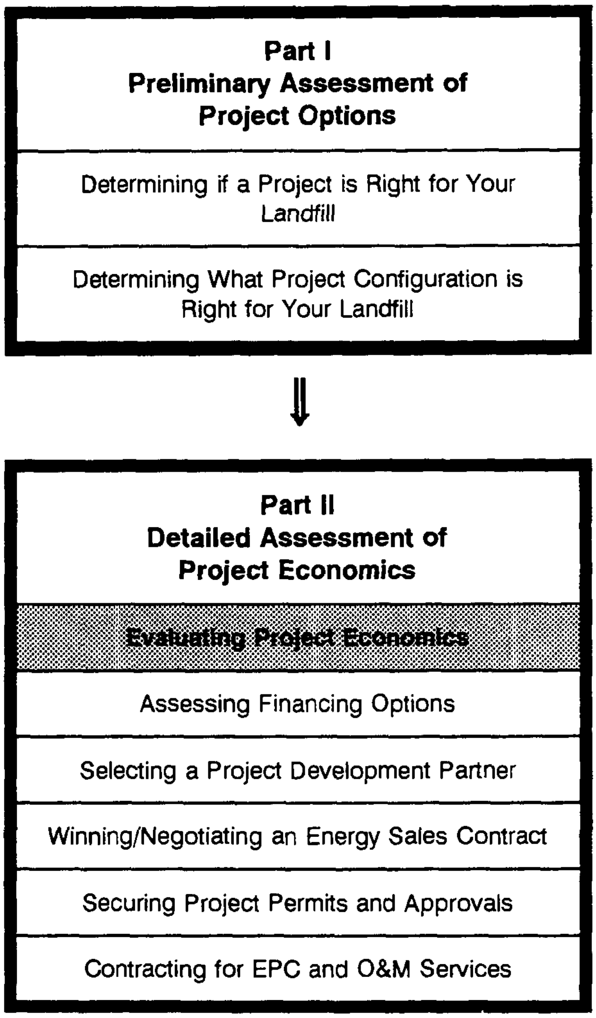
5. EVALUATING PROJECT ECONOMICS

After the available quantity of landfill gas has been estimated and a preliminary assessment of project options has been completed, the next step in developing a landfill gas energy recovery project is a detailed economic assessment of converting landfill gas into a marketable energy product. The economics of a landfill gas-to-energy project depend on a number of factors, including landfill gas quantity, local energy prices, and equipment choice. This chapter presents a methodology for evaluating project economics, and shows sample economic evaluations for the principal energy recovery options. Once economic feasibility has been determined, the cost and financial performance data from the economic analysis can be carried forward to the assessment of financing options, partner selection, and negotiation of energy sales and equipment contracts, which are discussed in subsequent chapters.

The Project Development Process



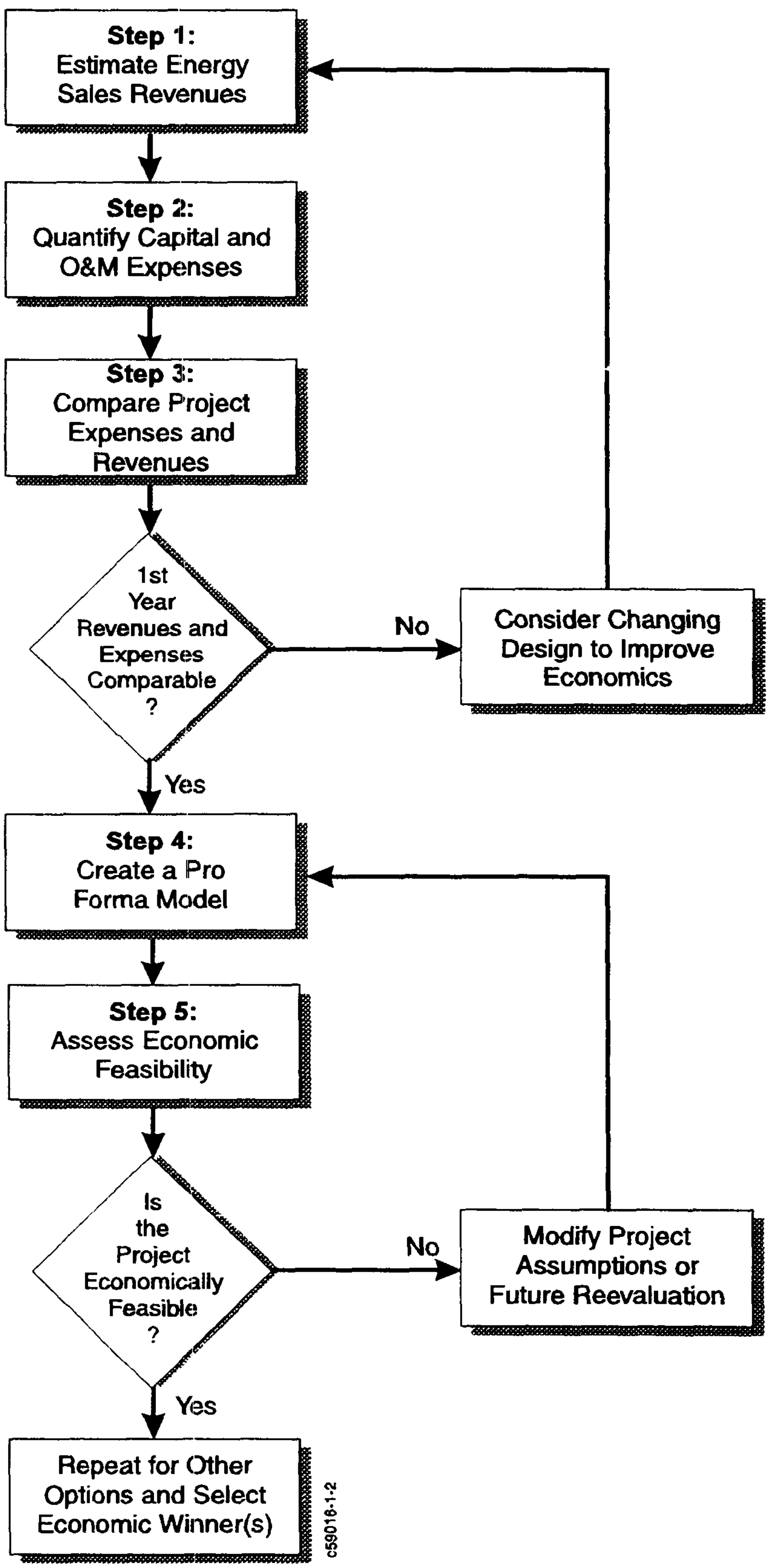
5.1 ECONOMIC EVALUATION PROCESS

An economic evaluation of a potential energy recovery project involves comparing the expenses of a particular project with the revenues that it is likely to receive. Figure 5.1 outlines the basic steps of the economic evaluation of energy recovery projects, and these steps are described in more detail below.

- Step 1. Estimate Energy Sales Revenues – Energy sales revenues include any cash that flows to the project from sales of electricity, steam, gas, or other derived products. Potential markets for energy products include electric utilities, municipal utilities, industrial plants, commercial or public facilities, and fuel companies. Revenues to the landfill gas energy recovery project are usually calculated based on the estimated quantity of energy delivered and the contract prices paid by the customer.

- Step 2. Quantify Capital and O&M Expenses – This step involves quantifying the capital costs and operation and maintenance (O&M) costs, plus in some cases landfill gas royalties and/or fees. Capital costs include not only the initial cost of the equipment, but also installation costs, debt service, owner's costs,

Figure 5-1 The Economic Evaluation Process



and returns on equity. Many of these costs vary with site-specific characteristics of the landfill.

- Step 3. Compare Project Expenses and Revenues – Once the estimates of the project's expenses and revenues have been made, an initial assessment of project economics can be made by checking to see if the first-year expenses and revenues are roughly equivalent. If they are comparable in the first year of project operation, then further economic evaluation is warranted. If not, it is usually necessary to re-examine technology, design, cost assumptions, and/or energy revenue assumptions to find ways to improve the economics.

- Step 4. Create a Pro Forma Model of Cash Flows – For a more accurate estimate of the probable lifetime economic performance of a project, the expenses and revenues should be calculated and compared on a year-by-year basis over the expected life of the project. This in-depth economic analysis, known as a pro forma, typically includes detailed calculations of project performance over time, escalation in project expenses and energy prices, financing costs, and tax considerations (e.g., depreciation, income tax).

- Step 5. Assess Economic Feasibility – Based on the pro forma model, the project economic feasibility can be assessed by calculating annual net cash flows, the net present value of future cash flows, and/or the owner's rate of return. These measures of financial performance are calculated over the life of the project and are the most reliable measures of economic performance. If these indicators are below the project proponent's criteria, he or she should re-examine the project for assumptions and/or options that can be modified.

If a landfill owner/operator has the opportunity to produce and sell more than one type of energy product, then the net cash flows of each option should be compared head-to-head to determine the best option. Cash flows of competing projects can be compared on an annual, net present value, and/or rate of return basis. After selecting an economic winner, the landfill owner/operator should then consider non-price factors including risks, ability to obtain financial backing, environmental performance, and reliability of assumptions. The option that produces the best financial performance while meeting the desired environmental, risk, and operating requirements is the overall winner.

The remainder of this chapter discusses the process of conducting a step-by-step economic analysis for the various landfill gas energy recovery options. The economic analyses presented in this chapter provide the landfill owner/operator with basic estimates of project costs and market prices for energy products. The landfill owner/operator can use the concepts presented to create his or her own economic analysis.

Example Landfill

Throughout this chapter, the key aspects of the economic evaluation process are illustrated with examples. These examples are based on a hypothetical landfill with 5 million metric tons of waste in place and a net sustainable landfill gas production level of 2,988 mcf/day. Box 5.1 presents the operating and cost assumptions that are used consistently in this chapter.

Appendix A contains the supporting performance and cost calculations for the 5 million metric ton example, and for two other landfill sizes--1 million metric tons and 10 million metric tons. Appendix A also contains sample cost calculations for a medium-Btu gas sales project.

5.2 POWER GENERATION/COGENERATION

The opportunity to collect landfill gas and burn it to produce electric power is available to most landfill owners. Whether or not this option is economically feasible depends largely on local electricity prices, which vary dramatically across regions of the country. Other important factors include access to electricity purchasers, landfill gas volume, and technology selection. This section presents a sample economic analysis – using the five steps outlined above - for a landfill gas power generation project.

5.2.1 Step 1: Estimate Energy Sales Revenues

A landfill gas power project can have one or more sources of revenue, depending on whether it produces just electricity or also cogenerates steam and/or other thermal energy. An important potential source of revenue is use of a portion of the landfill gas or the derived electricity or steam to offset energy costs (e.g., natural gas, oil, electricity) at its own facilities. The savings that are achieved by offsetting energy purchases can be counted as a type of revenue. The following paragraphs describe the principal sources of revenue for power projects.

Electric Buyback Rate

The economic factor that will usually have the greatest impact on a power project's economic feasibility is the local electric utility's buyback rate (i.e., the price the utility is willing to pay for the electricity produced by a non-utility electric generator). The buyback rate reflects the utility's own avoided costs of generating electricity, incorporating the cost of building new generating capacity if needed. The costs of generating electricity, and thus buyback rates, vary considerably among utilities and regions. Factors such as fuel mix, availability of cheap hydropower, utility financial health, and reserve margins have a large influence over local electricity costs and the rate (i.e., price) at which electric utilities will buy electricity from a landfill gas project.

U.S. electric utilities are currently required by the Public Utility Regulatory Policies Act (PURPA) to buy electricity from qualifying facilities, which include small power producers and cogenerators. Small power producers are defined as electric generating facilities that produce up to 80 MW and use mostly non-fossil fuels. Landfill gas energy recovery facilities are eligible to be classified under PURPA as small power producers. PURPA dictates that electric utilities must buy electricity at a rate no higher than the utility's "avoided cost," which is the cost that the utility would pay to generate the next increment of electricity using its own resources.

Avoided costs are typically filed with the state utility regulators on a regular basis, and some utilities publish buyback tariffs, accompanied by standard offer contracts, based on their avoided cost. (More information on standard offer contracts is provided in Chapter 8.) Utility buyback tariffs regularly include an avoided energy price, and some utilities also pay an additional component for their avoided capacity costs. The energy price component is based

Box 5.1 Assumptions for 5 Million Metric Ton Landfill Example

Operating Assumptions

Waste in place:	5 million metric tons
Collection efficiency:	85%
Net sustainable LFG production:	2,988 mcf/day
LFG calculation method:	EPA Report to Congress Equation [EPA]
Electric output calculation:	kw = (cf/hr) x (500 Btu/cf) / (Btu/kwh)
Electric heat rate (Btu/kwh):	12,000 for IC engine & CT 8,500 for combined cycle CT
Online date:	June, 1996
Annual capacity factor:	80%
Annual full load operating hours:	7,008

Capital Cost Assumptions

Energy conversion system cost includes engine/generator, auxiliary equipment, interconnections, gas compressor, and construction costs.

LFG collection system includes collection wells, blower, and flare system.

Engineering costs = 5% of installed equipment costs.

Soft costs include owners' costs (e.g., legal, permitting, insurance, taxes), escalation during construction, interest during construction, and contingency.

Incremental Capital Requirement = Total Costs - LFG Collection System Costs.

Cost of Electricity

Cost of Electricity = Capital component + O&M component + Royalty

Capital Charge Rate assumptions:

Project Finance Case

- 20 year project life
- 80% debt, 20% equity
- 9% interest on debt
- 15% return on equity
- 10-year depreciation

Muni Finance Case

- 20 year project life
- 100% tax-exempt bonds
- 6.5% interest on debt
- No income tax

Royalty/gas payment estimated at 0.5 ¢/kWh (about 10% of project revenues).

on the utility's fuel costs and operation and maintenance costs, which may vary depending on the time of day or year. The capacity price component is usually fixed, based on the utility's cost of building or buying additional capacity. Only utilities that actually need additional generating capacity will typically offer a capacity price component.

The avoided energy price component alone may not be enough to support a landfill gas power project. In these cases, landfill gas power project developers must seek electric utility customers that need additional capacity and are offering a capacity price component as well. Some utilities might offer a premium for renewable energy or environmentally beneficial projects such as landfill gas energy recovery. In some cases the utility's published tariff will be acceptable, but more often the project developer must attempt to negotiate a more favorable rate. (Chapter 8 discusses the different avenues to obtaining power sales contracts.)

In addition to possible sales to an electric utility, state regulators may allow direct electricity sales to one or more local customers. These sales are usually conditioned on the fact that they are limited to a number of contiguous neighbors. If such sales are allowed, the landfill gas power project must negotiate a rate with the customer. It is usually necessary to offer the customer an electricity rate that provides a discount over the rate currently paid to the local utility, unless the project is offering something that the local utility does not, such as higher reliability. Since retail electric rates are typically higher than the buyback rates offered, this type of arrangement can be very attractive to the seller and the buyer.

Historically, landfill gas power projects have received electric buyback rates ranging from ¢2/kWh to ¢10/kWh, averaging about ¢6/kWh. However, newer projects generally report receiving only ¢3/kWh to ¢4/kWh [EPA, 1993]. The chief reasons for lower rates in recent years are a slowdown in the rate of electric demand growth, and an abundance of generating capacity in some parts of the country (e.g., Southwest, New England). Generally, significant economic potential for landfill gas power projects exists where electric buyback rates are above ¢4/kWh, although technology improvements, emerging applications, and requirements to recover landfill gas for environmental reasons are increasingly making projects viable at rates below ¢4/kWh [EPA, 1993].

Displacement of On-Site Energy Purchases

It may be practical to use a portion of the generated electricity to displace some or all of the electricity purchases at commonly-owned facilities near the project site. For example, for a county-owned landfill, opportunities for displacement savings may include energy use at county office buildings, maintenance shops, water treatment plants, community centers, and correctional facilities. Displacement savings are calculated by determining the amount of on-site electricity usage that can be met by the energy project, then determining the cost of that electricity usage, based on the current retail rates or recent electric bills. The retail rates paid by the landfill owner/operator to the utility are typically higher than the buyback rate offered by the utility to purchase the power.

Displacement savings may also be achieved when the landfill owner/operator can use a portion of the landfill gas produced to offset natural gas or oil purchases at nearby facilities under the same ownership. The economic incentive for the owner/operator to try and offset these fuel costs will mainly be determined by the landfill's proximity to facilities that use natural gas or oil to meet process or heating needs. The savings possible from these offsets will depend on the existing fuel costs of the facilities and the amount of landfill gas that can

Box 5.2 Displacement of Energy Purchases at the Prince George's County Correctional Complex

The Brown Station Road Landfill (4 million tons waste in place and growing) in Prince George's County, Maryland provides landfill gas to meet the electrical and heating needs of the County Correctional Complex. This energy recovery system generates electricity using three 850-kw IC engine generators and also delivers medium-Btu gas to two conventional boilers located at the correctional complex. The three electric generators provide almost all of the correctional complex's electrical needs; excess electricity generated by the project is sold to the local electric utility (PEPCO). The boilers, which were originally designed to burn No. 2 fuel oil or natural gas, were adapted for landfill gas fuel and provide heat and hot water for the correctional complex. The project configuration was selected from among several options based on an economic comparison which examined lifetime costs and revenue to the county.

The project displaces most of the county's electricity and heating fuel costs associated with the correctional complex. The county estimates that the gross benefits are about $1.2 million per year in energy cost savings [Augenstein and Pacey, 1992].

be used by the facilities. Box 5.2 describes a landfill gas energy recovery project that displaces boiler fuel purchases and generates electricity for a Prince George's County, Maryland facility.

Thermal Energy Revenues

Landfill gas energy recovery projects can generate thermal energy such as steam or chilled water for use in nearby industrial plants or commercial facilities (e.g., hospitals, office buildings, hotels, universities). The economic incentive to cogenerate steam and other forms of thermal energy along with electricity using a cogeneration configuration is determined mainly by the potential customer's existing costs of generating thermal energy, and by the project's proximity to the customers. Typical steam costs range from $1.5 per million Btu (MMBtu) to $6/MMBtu, depending on the existing fuel and technology being used. Steam generation from waste fuels, wood, and sometimes coal can achieve costs at the low end of this range, while gas- and oil-fired steam is usually more expensive. Landfill project owner/developers should expect to offer some discount, often on the order of 5% to 30%, over a potential customer's current steam cost in order to be attractive.

Sample Calculation of First Year Revenues

For the hypothetical 5 million metric ton landfill described in Box 5.1, revenues are assumed to be created by generating electricity for: (1) sale to the local electric utility; and (2) displacement of retail electric purchases at a municipal office building. This example assumes that the electric buyback rate in 1996 is ¢4.8/kWh. It also assumes that there is a nearby office building, owned by the landfill owner/operator, that consumes 3 million kWh per year at a retail rate of ¢5.9/kWh in 1996. Table 5-1 presents a calculation of first-year revenues, which range from $1.7 million for an IC engine system to $2.3 million for a combined-cycle CT system. The combined-cycle CT produces more revenues than the other

Table 5.1 Estimated First-Year Power Project Revenues at Example Landfill

Example: Landfill waste in place = 5 million metric tons

	Units	IC Engine	Combustion Turbine	Combined Cycle CT	
PROJECT OPERATING DATA					
Net sustainable landfill gas production	mcf/day	2,988	2,988	2,988	(a)
Gross electric output	kW	5,188	5,188	7,324	
Net electric output	kW	4,934	4,727	6,763	
Annual electricity generated	kWh	34,577,472	33,126,816	47,395,104	
Annual electricity sold					
Net electricity sold to utility	kWh	31,577,472	30,126,816	44,395,104	
Electricity used on-site	kWh	3,000,000	3,000,000	3,000,000	(b)
ELECTRICITY PRICES					(b)
Buy-back price	c/kWh	4.8	4.8	4.8	
Retail price	c/kWh	5.9	5.9	5.9	
ANNUAL EXAMPLE REVENUES					
Electricity Sales to Utility in 1st Year	$000	$1,522	$1,452	$2,140	(c)
Electricity Sales On-Site in 1st Year	$000	$177	$177	$177	(d)
Total Annual Revenues	**$000**	**$1,699**	**$1,629**	**$2,317**	
Revenues per kWh sold	c/kWh	4.9	4.9	4.9	(e)

Notes:

(a) Calculated using statistical model 4.2 in EPA Report to Congress. [EPA] The resulting methane production estimate is within the range predicted by the models presented in Part I.

(b) Assumed for example purposes.

(c) Product of utility sales kWh and assumed 1996 buyback electricity rate of 4.8 c/kWh.

(d) Product of on-site sales kWh and assumed 1996 retail electricity rate of 5.9 c/kWh.

(e) Total annual revenues divided by total kWh generated. Note that this shows potential revenues, not the cost of generating electricity from landfill gas.

technologies because it generates more electricity, but the Step 2 analysis will show that the combined-cycle CT is also more expensive to build. The first-year revenues amount to ¢4.9/kWh for all three technologies on a per kWh basis, calculated by dividing the annual revenues by the total kWh generated and sold. In Step 3 this revenue estimate will be compared against the cost of generating electricity from landfill gas, which varies significantly among the technologies as described in the next section.

5.2.2 Step 2: Quantify Capital and O&M Expenses

To evaluate the economic feasibility of a landfill gas power project, the project expenses must be subtracted from revenues to determine potential gains (or losses). The chief project expenses are the amortization of up-front capital costs and the annual O&M expenses. Some projects have other expenses such as payment of fees or royalties for landfill gas rights. The following sections describe the different categories of project expenses.

Capital Costs

The total capital requirement for a landfill gas power project includes the costs of the major equipment (e.g., engine, CT), as well as the costs associated with the auxiliary equipment, construction, emissions controls, interconnections, gas compression and treatment, engineering, and "soft costs." Soft costs typically include up-front owner's costs (e.g., development staff, legal, permitting, insurance, property tax), escalation during construction, interest during construction, and owner's contingency, all of which are real costs incurred prior to and during the construction process.

The costs of the landfill gas collection system (e.g., equipment, installation, soft costs) can be excluded from the economic analysis if the collection system is either already in place or required by air emissions regulations. The energy recovery system can then be evaluated using an incremental cost approach. Under the incremental cost approach, the collection system costs are not included because these are sunk costs that would be incurred whether the recovered landfill gas is put to use or just flared. In the 5 million metric ton landfill example, the total cost includes the costs associated with the energy conversion system plus the landfill gas collection system, while the incremental cost does not include the capital or O&M costs associated with the landfill gas collection system.

Capital costs for landfill gas power projects vary widely depending on landfill size, conversion technology, and project design. Table 5-2 presents the estimated capital costs of landfill energy recovery systems for landfills with 1, 5, and 10 million metric tons of waste in place. For these hypothetical energy recovery projects beginning operation in 1996, the total capital requirement is estimated to range between $1,595/kW and $2,423/kW, and the incremental capital requirement is estimated to range between $1,109/kW and $1,691/kW[1]. These cost data are expressed in as-spent dollars, which means that equipment cost escalation (e.g., inflation) prior to and during construction is included in the cost estimate. As

[1] Not included in the capital cost data are preliminary project development expenses, the major component of which is landfill gas quantity testing. The most reliable method of testing is to drill test wells and conduct a pump test. Test wells typically cost between $5,000 and $10,000 per well [Smithberger, 1994; Merry, 1994], and the number of wells required to accurately predict landfill gas quantity will depend on a number of factors such as landfill size and waste homogeneity.

the cost data show, the capital cost per kW generated ($/kW) generally decreases with increasing project size, owing mainly to economies of scale, particularly for the CT-based technologies.

In the example cost calculation for the 5 million metric ton landfill producing about 3 million cf of landfill gas per day in 1996, the total capital requirement ranges from $1,675/kW for an IC engine system to $2,025/kW for a combined-cycle CT system, including the cost of the gas collection system (see Table 5-3). On an incremental basis, the capital requirement ranges from $1,177/kW for the IC engine to $1,658/kW for the combined-cycle CT. These costs are in as-spent dollars, reflecting a June 1996 on-line date. A boiler/steam turbine system would not be economically competitive at this size, but boiler/steam turbine system costs would probably become competitive at larger gas flow rates above roughly 5 to 7 million cf/day.

Although capital cost is the major determinant of the cost of generating electricity from landfill gas projects, the technology with the lowest capital cost is not always the choice. A good example is the 10 million metric ton landfill case presented in Appendix A. In that case, the IC engine has the lowest capital cost, but after O&M and royalty expenses are taken into account, the CT option yields the lowest cost of electricity. Other factors such as reliability and emissions also should be considered when deciding among technologies (see Part I for more on technology issues).

O&M Expenses

The O&M expenses vary considerably among projects due to different equipment types and gas treatment processes. Typically, O&M expenses include both fixed and variable expenses, as described in Box 5.3. Fixed O&M expenses are predictable and are not dependent on the amount of time that the project operates or the amount of electricity generated. Variable O&M expenses are usually dependent on the amount of time that the project operates, which can be measured by the amount of electricity (i.e., kWh) produced.

The total generator system O&M costs for IC engines are about ¢1.8/kWh in 1996 dollars [EPA, 1993]. The O&M costs associated with the gas collection system are about ¢0.5/kWh [EPA, 1993]. The O&M costs for CT-based systems are generally lower than those for IC engine-based projects [Wolfe and Maxwell].

Royalties/Gas Payments

The project developer may also need to pay for the gas received in the form of royalty payments to the owner of the gas rights and/or as gas payments to a gas company that collects and delivers the landfill gas. Royalties can be viewed as compensation for gas rights or as a financial incentive for allowing the project to be developed. Historically, power project owners have paid royalties to landfill owners equal to 10% to 12.5% of project revenues [Jansen, 1992; Augenstein and Pacey, 1992]. In recent years, the tightening of project financial margins has caused a reduction or elimination of pure royalty payments to landfill owner/operators. Royalties that are still paid are usually paid by the gas company.

Gas payments are made by generation companies or other end users for delivery of the gas. Gas payments are necessary in order for the project to take advantage of certain tax credits, because the gas must be sold to an unrelated party (e.g., power generator, industrial user). Tax credits are discussed in more detail later in this chapter.

Table 5.2 Estimated Power Project Capital Costs for Three Landfill Sizes

LANDFILL SIZE Waste in Place	Estimated Net Sustainable LFG Production (mcf/day)	Net Electric Output (kW)	CAPITAL COSTS Installed LFG Collection System ($/kW)	Installed Energy Conversion System ($/kW)	Total Soft Costs + Engineering ($/kW) (a)	Total Capital Requirement ($/kW)	Incremental Capital Requirement ($/kW) (b)
1 million metric tons							
IC Engine	642	984	$638	$1,052	$310	$2,000	$1,283
Combustion Turbine	642	963	$652	$1,412	$359	$2,423	$1,691
5 million metric tons							
IC Engine	2,988	4,934	$423	$958	$294	$1,675	$1,177
Combustion Turbine	2,988	4,727	$442	$1,153	$334	$1,928	$1,409
Combined Cycle CT	2,988	6,763	$309	$1,360	$356	$2,025	$1,658
10 million metric tons							
IC Engine	5,266	8,709	$413	$919	$263	$1,595	$1,109
Combustion Turbine	5,266	8,344	$431	$1,037	$288	$1,756	$1,249
Combined Cycle CT	5,266	12,008	$300	$1,208	$306	$1,813	$1,458

Notes:

Source is cost calculation tables for each size landfill (see Appendix A).

All costs are based on net electric (kW) output.

(a) Included are owners' costs (legal, permitting, insurance, taxes), escalation during construction (6 – 24 mos) and interest during construction.

(b) Excludes capital and soft costs associated with the LFG collection system.

Table 5.3 Estimated Power Project Capital Costs at Example Landfill

Example: Landfill waste in place = 5 million metric tons

Cost Category	Units	IC Engine	Combustion Turbine	Combined Cycle CT	
OPERATING DATA					
Net electric output	kW	4,934	4,727	6,763	
On-line date		6/96	6/96	6/96	
EQUIPMENT & INSTALLATION COSTS					
Energy Conversion System ($1994)	$000	4,725	5,450	9,200	
LFG Collection System ($1994)	$000	2,088	2,088	2,088	
Engineering ($1994) @ 5.0%	$000	341	377	564	
CAPITAL REQUIREMENT					
System cost ($1994)	$000	7,154	7,915	11,853	
Soft Costs	$000	1,109	1,200	1,841	
Total Capital Requirement	$000	8,263	9,115	13,694	
(as-spent dollars, 1996 on-line date)	$/kW net	1,675	1,928	2,025	
Incremental Capital Requirement	$000	5,807	6,659	11,216	(a)
(as-spent dollars, 1996 on-line date)	$/kW net	1,177	1,409	1,658	

Notes:

See Chapter Appendix for notes on these calculations.

(a) Excludes capital and soft costs associated with the LFG collection system.

Box 5.3 Classification of O&M Expenses

O&M expenses include both fixed and variable expenses, as shown below.

Fixed O&M expenses	Variable O&M expenses
Labor	Periodic maintenance and overhauls
Property taxes	Water
Insurance	Consumables (e.g., lubricating oil, hydraulic fluid, filters)
Administrative expenses	
Spare parts	
Fees	
Emissions offsets	

The distinction between fixed and variable expenses is important, because fixed O&M expenses are incurred regardless of the amount of electricity generated.

The 5 million metric ton landfill example includes an annual royalty payment/gas payment equal to about 10% of revenues. Including a royalty/gas expense demonstrates the economic effect that royalties have; namely, they make landfill gas projects more expensive. In the example, paying the royalty increases costs by ¢0.5/kWh, which could make the difference between an economically attractive project and an unattractive project. In the future, landfill owner/operators may have additional incentive to forego royalty payments because of the environmental benefit of a landfill gas recovery project.

Estimating the Cost of Electricity

The cost of generating electricity (¢/kWh) from a landfill gas power project is equivalent to the sum of capital expenses, O&M expenses, and royalty/gas expenses (if any), divided by the kWh of electricity delivered. Estimating this cost has two steps:

(1) Amortize capital costs and divide by the annual kWh produced; and
(2) Add O&M and royalty expenses.

Each of these steps is described below and illustrated with an example.

Step 1: Amortize Capital Costs: Capital costs are commonly "levelized," or amortized in equal annual amounts over the economic life of the project (i.e., over the period that the project will generate revenues). If the productive landfill life is 20 years, then a typical term for the levelized capital cost calculation would be 20 years. For the purposes of economic analysis, the capital costs are often amortized using a capital charge rate (CCR). A CCR is used to convert the installed cost into a levelized capital cost that can be charged to the project in each year of the project life. The CCR is the levelized percentage of the total capital that must be recovered in each year to cover:

- return of equity;

- return on equity;
- interest on debt;
- depreciation;
- general and administrative expenses;
- property tax; and
- income tax.

The CCR can be calculated by estimating annual interest and return on equity payments on the outstanding loan value over the life of the project (similar to a home mortgage) and adding annual amounts for depreciation, expenses, and taxes. The main variables in the CCR calculation are the debt/equity ratio and interest rates. The CCR for a privately financed landfill gas-to-energy project will be higher than the CCR for a project financed with municipal bonds (More detailed information regarding CCRs under different financing scenarios is contained in Chapter 6.):

- **Project Finance Case:** A CCR of approximately 0.136 would result in the case where a project is financed with a debt/equity ratio of 80/20, a nominal interest rate on debt of 9%,[2] an after tax return on equity of 15%, and a 10-year tax depreciation. (To take advantage of 10-year depreciation, the project life is assumed to be just under 20 years.)[3]

- **Municipal Bond Finance Case:** Thus, a CCR of approximately 0.111 would result from the case where a project is financed with 100% municipal tax-exempt bonds that have a 6.5% interest rate.

To obtain a levelized capital cost (LCC) in ¢/kWh units, the annual cost calculated as described above must be divided by the expected operating hours per year as follows:

$$LCC = \text{Installed Cost} \times CCR \,/\, (CF \times \text{Hours per Year}) \times (¢100/\$) \quad \text{(Eq. 5.1)}$$

where:

LCC	=	levelized capital cost (¢/kWh)
Installed Cost	=	total or incremental capital requirement ($/kW)
CCR	=	capital charge rate
CF	=	annual average capacity factor
Hours per year	=	8,760

Using the 5 million metric ton landfill example, the levelized capital cost for the IC

[2] Interest rates are determined by the prevailing rate indicators (e.g., U.S. treasuries, prime rate, LIBOR) and a host of project- and lender-specific factors. When this document was written, rates for nonrecourse debt for a "strong" landfill gas project ranged from 9% to 9.8%. [Seifullin, 1995; DePrinzio, 1995] Increasing interest rates by 1% would cause the cost of electricity to increase by 2% to 3%.

[3] Landfill gas energy recovery projects appear to be eligible to use 10-year depreciation for income tax purposes. [Jansen, 1992; Mumford and Lacher, 1993] Property with a life of 16 years or more, but less than 20 years, can use the 10-year Modified Accelerated Cost Recovery System (MACRS) depreciation schedule. [RIA, 1992]

engine option would be ¢3.2/kWh, calculated as follows using an 80% capacity factor[4]:

¢3.2/kWh = ($1,675/kW x 0.136) / (80% x 8760 hrs) x (¢100/$)

If the project were financed with 100% tax-exempt municipal bonds (CCR = 0.111), the levelized capital cost would be ¢2.7/kWh.

Step 2: Add O&M Expenses: This step is straightforward--add the estimated O&M expenses and royalty expenses (if any) to the capital expense to get the total cost of electricity.

Based on the capital, O&M, and royalty expenses discussed above, the total first year cost of generating electricity from the 5 million metric ton landfill in 1996 are presented in Table 5-4. As the table shows, the cost of the conversion system plus the gas collection system could range from ¢6.0/kWh to ¢6.5/kWh if the project were financed with 80% debt and 20% equity. Financing 100% of the project costs with tax-exempt municipal bonds would achieve a cost of electricity ranging from ¢5.5/kWh to ¢5.8/kWh. The incremental cost of electricity, which excludes collection system costs, would be approximately 20% to 25% lower, or ¢4.6/kWh to ¢5.3/kWh for the project finance case, and ¢4.2/kWh to ¢4.7/kWh for the municipal bond finance case. [Note that these costs of electricity include a royalty payment of ¢0.5/kWh and do not include the effects of incentives, which could trim another ¢1/kWh or more off the electricity cost if applicable (incentives are factored into the calculation in Step 3).]

The IC engine appears at this landfill size to have a slight cost advantage over the CT and a substantial advantage over the combined-cycle CT, owing mainly to the IC engine's lower engine and gas compressor costs, and gas compressor auxiliary load. However, the IC engine loses some of its advantage because of higher O&M costs.

5.2.3 Step 3: Compare Project Expenses and Revenues

As a first cut at assessing a particular project's economics, first-year expenses and revenues are often compared to see if a project configuration warrants further analysis. At this point it is important to include any tax credits or other incentives in the economic assessment. If first-year project revenues are comparable with expenses, making sure to take into account any tax credits that are available, then it is advisable to proceed to the next step: creating a pro forma model of project cash flows. If the estimated revenues fall significantly short of the project costs, one or both of the following two options should be pursued:

1) Look for additional sources of revenue (e.g., on-site sales, thermal sales) or alternative customers (e.g., electric utilities, municipal utilities) that may offer a higher electricity price; and/or

2) Change the project configuration (e.g., size, technology, equipment vendor, energy outputs) and re-examine the economics.

[4] See Box 3.6 in Chapter 3 for a discussion of capacity factors.

Table 5.4. Estimated Cost of Electricity Production for Three Project Configurations at Example Landfill

Example: Landfill waste in place = 5 million metric tons

	Units	IC Engine	Combustion Turbine	Combined Cycle CT	
Total Electricity Cost in 1996					
Project Finance Case (80% debt, 20% equity)	c/kWh	6.0	6.2	6.5	
Municipal Finance Case (tax-exempt bonds at 6.5%)	c/kWh	5.5	5.6	5.8	
Incremental Electricity Cost in 1996					(a)
Project Finance Case (80% debt, 20% equity)	c/kWh	4.6	4.7	5.3	
Municipal Finance Case (tax-exempt bonds at 6.5%)	c/kWh	4.2	4.2	4.7	

Notes:

See Chapter Appendix for notes on these calculations.

All cost estimates include a 0.5 c/kWh royalty payment. Tax incentives and subsidies are not included.

(a) Incremental Electricity Cost does not include capital and O&M costs associated with LFG collection system.

Tax Credits/Incentives

Tax credits and federal incentive payments can significantly improve project economics, and help to justify an otherwise marginal project. Currently, federal tax credits listed under Section 29 of the Internal Revenue Code are available for the recovery and use of unconventional gas fuels such as landfill gas. Additionally, the "Renewable Energy Production Incentive" (REPI) program, which was mandated under the 1992 Energy Policy Act and is being implemented by the U.S. Department of Energy, provides an incentive to publicly owned facilities that generate electricity from renewable energy sources such as landfill gas. The applicability of these incentives depends on the structure of the project and the owner/operators' tax situation. Therefore, a full understanding of the tax laws and how they may be applied is critical to ensuring a project's ability to take advantage of the incentives.

<u>Section 29:</u> The Internal Revenue Service (IRS) Section 29 tax credit, currently due to expire in the year 2007, is available to landfill gas projects that are operating before June 30, 1998. This tax credit has been extended several times by the U.S. Congress since its initial inception, but there are no guarantees that the extensions will continue. The credit is worth $5.83 per barrel of oil-equivalent (on a MMBtu basis) and is adjusted annually for inflation [Conversation with Tommy Thompson, U.S. Internal Revenue Service, April 1996]. The current value of the credit is $1.001 per MMBtu [Conversation with Tommy Thompson, U.S. Internal Revenue Service, April 1996]. At full value, this converts to about 0.9¢ to 1.3¢/kWh for a typical landfill gas electricity project, depending on the efficiency of the generating equipment used.

The Section 29 tax credits apply only to landfill gas that is produced and then sold to an unrelated third party (for example, when landfill gas is sold as a medium-Btu fuel to an industrial customer) [RIA, 1992]. As a result of this stipulation, project developers may bring in or create a separate company when developing power projects in order to take advantage of the credits. Several project structures exist that would allow a landfill gas project to benefit, either directly or indirectly, from the tax credits. Three such structures are presented in Box 5.4. Depending on the structure used, the project may receive only a fraction of the value of the tax credits. For example, if a tax-paying company takes responsibility for gas collection and sells the gas to a power project, the collection company is entitled to the Section 29 tax credits. However, if this company cannot fully use the credits, as is often the case, the company might transfer the credits to outside investors who can use them. Usually the gas collection company must "sell" the tax credits at a discounted price, leaving the collection company with as little as 60% of the full value of the tax credits.

<u>REPI:</u> Section 1212 of the Energy Policy Act of 1992 stipulated that a cash subsidy of 1.5¢ per kWh (adjusted annually for inflation) would be available to renewable energy power projects owned by a state or local government or nonprofit electric cooperative, that are first used during the period October 1993 through September 2003 [Federal Register, July 19, 1995]. Solar, wind, geothermal (except dry steam geothermal), and biomass (including landfill gas, but excluding municipal solid waste) projects are defined to be renewable energy projects.

The availability of funding for REPI payments is subject to annual appropriation by Congress. Approximately $2.2 million was appropriated for the program for fiscal year 1995, and $3 million was appropriated for 1996 [Klunder, 1995]. Payments will be made first (and on a pro rata basis if necessary) to qualified renewable energy facilities

Box 5.4 Examples of How A Project Can Be Structured to Take Advantage of Section 29 Tax Credits

Privately Owned Landfill:

Scenario One:

- The landfill owner owns and operates the gas collection system (GASCO), and sells the gas to the developer for use in the energy recovery project (GENCO).
- The GENCO is owned and operated by a developer who is unrelated to the landfill owner.

Result: The landfill owner receives gas revenues and tax credits, which can be used or sold along with the GASCO to another party.

Publicly Owned Landfill:

The following scenarios describe structures that enable a landfill owner who cannot take direct advantage of tax credits (e.g., a municipality) to benefit from the transfer of credits.

Scenario One:

- An entity (GASCO) unrelated to the landfill owner purchases the gas rights from the landfill and operates the gas collection system. It sells the gas to the energy recovery project (GENCO).
- The GENCO is owned and operated by a developer who is unrelated to the landfill owner.

Result: The landfill owner receives a one-time payment for its gas rights, and the owner of the GASCO receives the tax credits.

Scenario Two:

- The landfill leases gas rights, for a "production fee," to an unrelated party (GASCO) who sells the gas to the energy recovery project (GENCO).
- The GENCO is owned and operated by a developer who is unrelated to the landfill owner.

Result: The landfill owner receives production payments and a share of the tax credits. The GASCO receives the majority of the tax credits.

In many of these cases, the developer of the energy recovery project and the purchaser/lessor of the gas rights may have overlapping ownership of up to 50%. [Martin, 95] using solar, wind, geothermal, and closed-loop biomass technologies.[5] Payments will then be made (on a pro rata basis if necessary) to all other qualified renewable energy facilities [10 CFR, Part 451] including landfill gas-to-energy facilities. The 1995 appropriation was enough to make all approved payments.

According to the rules governing the REPI program, projects must apply annually for the payments, which may continue for up to ten years. Applications for energy produced in a fiscal year must be submitted to the Department of Energy during the period October 1 through December 31 of the following fiscal year [10 CFR Part 451].

Example Calculation of Project Cash Flow (First Year)

An estimate of first year cash flow and economic viability is obtained by subtracting the first-year expenses from revenues, and adding available tax credits/incentives. If this calculation yields an amount of zero or greater (i.e., surplus cash flow), the assumed revenues can support the project expenses, as well as meet the project's financing requirements (e.g., a 15% return on equity in the project finance case). The financing requirements are included in this analysis as part of the project expenses. A negative result indicates a cash flow shortfall, which means that expenses will not be covered or debt service requirements will not be met in the first year. Since this calculation only provides a rough indication of economic viability, the most important result is simply whether or not the calculation yields a non-negative amount.

Continuing the 5 million metric ton landfill example, the assumed electric buyback rate of ¢4.8/kWh would be capable of supporting various project configurations depending on the financing assumptions and the cost basis assumption, as shown in Table 5-5. As shown in the table, all three technologies are estimated to be viable on an incremental cost basis for both the project finance and municipal bond finance cases. However, on a total cost basis, only the IC engine power configuration appears viable in the project finance case. In contrast, the cost advantages of municipal bond financing (tax exempt) allows all three technologies to be viable even under a total cost basis. This analysis demonstrates that the availability of municipal bond financing has an important effect on the economic viability of the technology options.

It is clear that for the example landfill, the IC engine power configuration appears most promising at this stage of the analysis, so the analysis of this option should proceed to Step 4. Because the CT option is relatively close to the IC engine under all scenarios, it would be reasonable to carry the CT forward for further evaluation in Step 4 as well. The combined-cycle CT should only be considered if municipal bond financing is an option.

Landfill gas power project economics have the potential to improve over time, but future performance must nevertheless be carefully examined. Economics can improve, because most of the costs are fixed (e.g., capital and gas collection costs) and not subject to significant escalation over time. Only the O&M costs are expected to increase significantly. Project revenues, which are driven by buyback rates, can increase over time and should more than offset any O&M increases. However, these positive effects can be easily negated by declining gas flows in later years, because the project will have diminished revenues (see

[5] Closed-loop biomass means any organic material from a plant which is planted exclusively for purposes of being used to generate electricity [10 CFR, Part 451].

Table 5.5 First Year Project Revenues and Expenses for Three Project Configurations at Example Landfill

Example: Landfill waste in place = 5 million metric tons

	Units	IC Engine	Combustion Turbine	Combined Cycle CT	
REVENUES	c/kWh	4.9	4.9	4.9	
PROJECT FINANCE CASE					
Expenses (including Owner's Return)					
Total	c/kWh	6.0	6.2	6.5	
Incremental	c/kWh	4.6	4.7	5.3	
Revenues Minus Expenses					
Total	c/kWh	(1.1)	(1.3)	(1.6)	
Incremental	c/kWh	0.3	0.2	(0.4)	
1996 Tax Credit	c/kWh	1.3	1.3	0.9	(a)
Estimated Surplus (Shortfall) Cash Flow After Taxes and Owner's Return					
Total Cost Basis	c/kWh	0.2	0.0	(0.7)	
	$000	$69	$0	($332)	
Incremental Cost Basis	c/kWh	1.6	1.5	0.5	
	$000	$553	$497	$237	
MUNICIPAL BOND FINANCE CASE					
Expenses (including financing costs)					
Total	c/kWh	5.0	5.1	5.3	
Incremental	c/kWh	3.7	3.7	4.2	
Revenues Minus Expenses					
Total	c/kWh	(0.1)	(0.2)	(0.4)	
Incremental	c/kWh	1.2	1.2	0.7	
1996 REPI Subsidy	c/kWh	0.0	0.0	0.0	
Estimated Surplus (Shortfall) Cash Flow After Taxes and Financing Expenses					
Total Cost Basis	c/kWh	(0.1)	(0.2)	(0.4)	
	$000	($35)	($66)	($190)	
Incremental Cost Basis	c/kWh	1.2	1.2	0.7	
	$000	$415	$398	$332	

Notes:

(a) In many cases, only a fraction of the tax credit gets applied to the project. If only 60% of the available credit gets applied, then the project becomes more expensive by about 0.5 c/kWh, or $173,000 per year.

See Appendix A for notes on calculations.

Chapter 3 for more on project sizing).

The results of the analysis are, of course, driven by the key assumptions that affect costs and revenues, including: incentives, royalty payments, capital and O&M costs, electric buyback rate, financing method, and annual capacity factor. In this example, the full value of tax credits or subsidies contribute 0.9¢/kWh to 1.5¢/kWh to project cash flows, and all scenarios include a royalty/gas payment expense of 0.5¢/kWh.

5.2.4 Step 4: Create a Pro Forma Model of Project Cash Flows

After an initial comparison of expenses and revenues has demonstrated that a particular project configuration could be competitive (e.g., IC engine, CT), the next step is to create a pro forma model of project cash flows over the life of the project. This type of cash flow model is known as pro forma because it usually contains several standard items including a listing of financial assumptions and operating parameters, energy pricing data, calculation of annual expenses and revenues, an income statement, a cash flow statement, and financial results (see Box 5.5). An income statement usually lists the elements of project revenues and expenses, and shows a calculation of operating income, depreciation, taxes, and net book income. A cash flow statement typically shows project cash flows including pre-tax and after-tax cash flows, and distributions to project owners. Financial results include debt coverage ratios, rate of return (ROR), and net present value (NPV).

Box 5.5 The Pro Forma

The elements of a well-designed pro forma include:

- Project specifications and cost data
- Operations summary (e.g., kwh generated, Btu delivered, gas consumed)
- Financing and depreciation summary (e.g., interest rates, schedules)
- Price escalators for fuels, consumables, services, equipment
- Operating expense calculation (annual costs for royalties, fuel, O&M)
- Revenue calculation (annual revenues from sales of electricity, energy)
- Financing costs (e.g., interest and principal payments, investor's cash flow)
- Income statement (calculation of operating income, book income)
- Income tax and tax credit calculation
- Cash flow statement (e.g., pre-tax and after-tax cash flow calculations)
- Financial performance calculation (e.g., debt coverages, ROR, NPV of cash flows)

A well-designed pro forma should give the owner/developer a clear idea of project revenues, expenses, and sensitivities, and it can also serve to convince investors of project financial viability and returns. Preparing a detailed pro forma is an important step in ensuring the financial feasibility of a landfill gas-to-energy project. The pro forma model is usually created by the project developer using a computer spreadsheet format, which makes it easy to change inputs and assumptions if needed. This feature also makes the pro forma a useful tool for testing the project's economic sensitivity to alternative assumptions and options.

A pro forma will yield a much more reliable assessment of economic viability than the first-year comparison. Therefore, it is generally recommended that a pro forma be developed for all options that achieve positive or close-to-positive results in Step 3.

5.2.5 Step 5: Assess Economic Feasibility

The key financial results of a pro forma model are used to assess the economic feasibility of a power project. Economic feasibility is usually measured by indicators such as debt coverage ratios, ROR on equity, and NPV. The debt coverage ratio, which is the annual ratio of operating income to the debt service requirement, is a measure of the project's ability to meet its debt repayment requirements, and is usually expected to be in the range of 1.3 to 1.5. Lenders often view projects with debt coverage ratios below 1.3 as having a high risk of defaulting on loan repayment, which can make financing difficult. The ROR on equity and the NPV of owner's cash flows are two measures of the financial returns to the project owner. The owner's rate of return on equity ranges from approximately 12% to 18% for most types of power projects.

An acceptable owner's ROR for a particular project is a function of project risks and the owner's objectives. If the landfill owner views the project mainly as a cost-effective pollution control measure, then financial returns are not the only consideration and a ROR of 12% or less may be acceptable. Likewise, if risks have been removed because extensive testing has been done or permits are in hand, then lower RORs may be acceptable. However, if uncertainties such as unconfirmed gas flow rates or potential permitting difficulties are present, then the owner/developer may expect a higher ROR to compensate for the risks.

5.3 Sale of Medium-Btu Gas

If there is a suitable buyer nearby, direct sales of medium-Btu gas is generally the most economic recovery option, because it entails minimum processing requirements and capital costs. The suitability of a potential buyer depends largely on two considerations: (1) the buyer's proximity to the landfill and (2) the buyer's gas requirements.

The proximity of a potential customer to the landfill is critical because the cost to deliver the gas may be prohibitive if the customer is located far from the landfill. Ideally, the customer will be no further than one to two miles away. If there are no potential customers nearby, it may be possible to entice new industrial facilities to locate near the landfill by offering a low cost fuel.[6]

The total *annual* gas or steam requirements of a potential customer are important, since they will determine whether landfill gas production rates will support the entire needs of the customer or only a portion. For example, a five million metric ton landfill could support the processing needs of a large kiln operation, while a one million metric ton landfill may only provide enough gas to supplement needs during peak periods. When evaluating the needs of a customer who will be using landfill gas in boilers to generate steam, a general rule of thumb is that approximately 10,000 pounds per hour of steam can be provided by every one

[6] New industries that are searching for a suitable facility location often work through local or state economic development specialists to identify candidate sites. Therefore, educating economic development specialists about the benefits of using landfill gas as a fuel so they can offer its advantages to potential customers may be worthwhile.

million metric tons of landfill waste in place.[7]

A potential buyer's *seasonal* gas demand is also important due to the nature of landfill gas production. If a customer has only an intermittent gas load, much of the landfill gas recovered will be flared rather than sold, since landfill gas storage is not economical. A baseload gas user which uses gas on a continuous basis is usually preferred over an intermittent user, such as a facility that uses gas mainly for seasonal heating needs. It is more difficult to justify the economics of selling gas to an intermittent user, because gas sales revenues are reduced during non-heating seasons and the landfill gas must be flared or used elsewhere.

Using landfill gas as a medium-Btu fuel in boilers that create steam to meet process or space heating needs is one of the simplest and most common direct use applications. Other industrial applications include drying operations, kiln operations, and cement and asphalt production. If one of these applications provides only a seasonal market for the landfill gas, multiple uses may be combined to achieve a continuous baseload. Box 5.6 describes how one company successfully created a year-round demand for its landfill gas production by combining the demands of its asphalt manufacturing operation with its space heating needs in the winter months. Another landfill gas application that may be ideal is to provide supplemental fuel to waste-to-energy plants, which are often located near landfills. For example, at the 45-MW Ridge waste-to-energy plant in Florida, landfill gas from the adjacent landfill comprises five percent of total fuel input on a heat-input basis [Swanekamp, 1994].

The economic viability of the project can be determined once a potential gas user has been identified using the steps described below.

5.3.1 Step 1: Estimate Energy Sales Revenues

Revenues for a medium-Btu gas project come from gas sales to a direct use customer. Potential landfill gas customers include industrial energy users, commercial buildings, universities, incinerators, and district heating systems. Typically, medium-Btu gas customers will buy landfill gas at a price that is no higher than their current delivered price of natural gas on a Btu basis, since landfill gas combustion may require burner retrofits, controls, and maintenance that natural gas does not. In fact, landfill gas project owner/developers should expect to offer landfill gas at a discount off the customer's current natural gas price; discounts of approximately ten to twenty percent are common in existing projects. Delivered natural gas prices vary by location and customer type. For example, the price paid by a large industrial gas user will likely be less than that of a customer who only uses gas for space heating purposes such as commercial buildings and district heating systems. Box 5.7 illustrates these price variations, which should be kept in mind when negotiating with potential customers.

Displacement savings, realized by using landfill gas to offset natural gas purchases at facilities owned by the landfill owner/operator, should also be credited to the project.

Tax credits or other incentives may be used to supplement gas revenues. However, if the tax credits are to be used by a third party developer, they may not yield full face value to the project since there are soft costs (i.e., legal and transaction fees) associated with placing

[7] This rule of thumb assumes that steam is supplied at 50 psig, saturated.

Box 5.6 Multiple End Uses of Landfill Gas Create a Baseload Demand for Fred Weber, Inc.

Fred Weber, Inc., a cement and asphalt producer, collects landfill gas from a landfill near St. Louis, Missouri and directly uses the medium-Btu gas in three different, seasonal applications, for savings of about $100,000 per year.

- In the summer months, landfill gas is burned in the aggregate dryer at the firm's asphalt plant which is located adjacent to the landfill.
- In the winter months, Fred Weber, Inc. uses landfill gas in its concrete plant to heat water for the preparation of ready-mixed concrete.
- Landfill gas is also used to heat the firm's adjacent commercial greenhouse.

By using landfill gas in complementary applications, Fred Weber, Inc. has created a baseload demand for its landfill gas supply.

[Mahin, 1991]

Box 5.7 Natural Gas Price Variations by Customer Type

Natural gas consumers can either purchase their own gas supplies and then pay the local distribution company (LDC) a delivery charge, or they can purchase delivered supplies directly from the LDC. Most large industrial and commercial consumers choose the former purchase alternative, since it is usually less expensive than buying from the LDC.

Regardless of the purchase strategy used, large industrial customers typically pay less for natural gas than other types of consumers:

	Industrial	Commercial	Residential
Average Price ($/mcf)	3.00	5.22	6.89

All dollar values are in 1994 dollars.

[Energy Information Administration, 1995]

the ownership of the gas rights and collection system with an independent party. In addition, if the company cannot fully use the credits , the company may transfer the credits to an outside investor. These outside investors usually buy the credits at a discounted price, leaving the sellers with as little as 60% of the full value of the tax credit.

5.3.2 Step 2: Quantify Capital and O&M Costs

The gas collection costs for a medium-Btu gas sales project would be similar to those incurred in a power project, although gas processing costs would probably be much less, since only minimal clean-up is usually required for direct use applications. The capital costs associated with delivering landfill gas to the customer would normally include pipeline construction costs (about $250,000 to $500,000 per mile, installed), additional gas compression costs, and metering. If there are low points in the pipeline which would allow moisture to accumulate, then the costs of installing dehydration equipment may also be incurred.

The customer may incur capital costs if equipment retrofits are necessary in order to burn landfill gas. For example, due to the lower flame temperature of landfill gas as compared to natural gas, lower boiler superheater temperatures may be experienced and thus a larger boiler superheater could be required [Eppich and Cosulich, 1993]. Retrofit costs will vary, since most require customized installation. For example, one project reported that new rotary kiln burners would cost $30,000 each [LaReaux, 1995], while boiler burner retrofits may range in cost from $120,000 to $300,000 [Brown, 1995]. The landfill project may assume some of these retrofit costs, as was the case in the AT&T project described in Box 5.8.

Box 5.8 Medium-Btu Gas Sales to AT&T

Network Energy of Ohio, owner of landfill gas rights at a landfill near Columbus, Ohio, is selling landfill gas to a nearby AT&T Network Wireless Systems plant. The AT&T plant uses the landfill gas as boiler fuel to generate about 40,000 pounds of steam per hour for plant heating, process uses, and hot water heating. Use of the landfill gas enables AT&T to reduce the purchases of its normal boiler fuel--natural gas. Even with some natural gas still used to supplement the landfill gas supply, AT&T expects to achieve annual fuel savings of about $100,000.

To make the medium-Btu purchase attractive to AT&T, Network Energy paid the $1 million cost of building a 1.5-mile pipeline from the landfill to the plant and converting one AT&T boiler to burn landfill gas. A custom low-NOx burner was designed by Coen Company to burn a controlled mixture of landfill gas and natural gas. The burner control system is able to respond to changes in landfill gas line pressure and Btu content.

The agreement between Network Energy and AT&T provides that all key boiler equipment installed in the conversion is owned by AT&T. In addition, AT&T had input in the design process and obtained the air permit for the modified burner. Network Energy is responsible for ensuring that all other environmental conditions are met [Source: Power, April 1994].

Table 5-6 shows the total capital costs for the example 5 million metric ton landfill, serving a gas consumer who is assumed to be located one mile away. The cost of providing gas to this customer is estimated to be $3.39 million, including the cost of the gas collection system. These costs (in as-spent dollars, reflecting a June 1996 on-line date) would increase with longer pipeline distances.

Table 5.6 Estimated Medium-BTU Project Capital Costs at Example Landfill

Example: Landfill waste in place = 5 million metric tons

Cost Category	Units	Baseload user (continuous)	Heat load user (seasonal)
OPERATING DATA			
Net sustainable landfill gas production	mcf/day	2,988	2,988
Net fuel output (MMBtu)	MMBtu/day	1,494	1,494
On-line date		6/96	6/96
Capacity factor (lifetime annual average)		90%	40% (a)
Annual full load operating hours	hours	7,884	3,504
Annual volume of gas sold	MMBtu	490,811	218,138
EQUIPMENT & INSTALLATION COSTS			
Gas Delivery System ($1994)			
Condensate removal/filtration	$000	15	15
Compressor/Blower station	$000	100	100
Pipeline interconnect	$000	350	350
Fuel burning equipment conversion	$000	150	150
Gas delivery system cost ($1994)		615	615
LFG collection system cost ($1994)	$000	2,098	2,098
Engineering ($1994)	$000	136	136
CAPITAL REQUIREMENT			
System cost ($1994)	$000	2,848	2,848
System cost ($1996)	$000	3,051	3,051
Soft costs($1996)			
Owners costs, escalation, interest		190	190
Contingency @5.0%		153	153
Total Soft Costs	$000	343	343
Total Capital Requirement			
(as-spent dollars, 1996 on-line date)	$000	3,394	3,394
Incremental Capital Requirement	$000	769	769 (b)

Notes:

See Chapter Appendix for notes on these calculations.

(a) Assumes baseload user has a year-round need for gas, and heat load user only uses gas in the five winter months.

(b) Excludes capital and soft costs associated with the LFG collection system.

O&M costs are relatively low for medium-Btu gas projects. The gas consumer is usually responsible for the O&M of its own fuel-burning equipment. For the project developer, gas delivery system O&M expenses might include pipeline marking costs (to prevent pipeline rupture during excavations), labor costs, insurance, and property taxes. The Wilder's Grove landfill gas project in North Carolina reports that its only routine gas delivery system maintenance tasks are to clean the automated condensate drain filter and replace the pumping station filter when significant pressure drops occur [Augenstein and Pacey, 1992]. Gas collection system O&M costs are calculated to be about $0.31 per MMBtu in 1996 dollars [EPA, 1993].

5.3.3 Step 3: Compare Project Expenses and Revenues

To evaluate the economics of selling medium-Btu gas, the expenses associated with collecting, processing, and delivering the landfill gas must be compared against the gas revenues. A first-year comparison can give a quick estimate of project economic feasibility, while a pro forma model of cash flows will provide a more precise model of economic performance.

Using the capital cost assumptions described in Table 5-6, the first year cost of producing a medium-Btu fuel for direct use can be calculated for the example 5 million metric ton landfill. The results are presented in Table 5-7. Costs are displayed in the example for a baseload gas user, who consumes gas at a relatively constant rate over the course of a day or year, and a heat load user, who consumes gas mainly for seasonal heating needs. The results of the cost calculations affirm the following conclusions about medium-Btu gas projects in general:

- The incremental cost of installing a gas delivery system is very low. For the example landfill, the cost of the gas delivery system represents only about 23% of the total capital requirement.

- The fuel consumption pattern of a potential gas customer greatly affects the unit cost of gas. The example shows that producing and delivering gas to a heat load only customer would cost over twice that of producing and delivering to a baseload customer ($2.87 per MMBtu versus $1.28 per MMBtu on a total system basis).

- IRS Section 29 tax credits can make a substantial difference in offsetting gas production costs. When the full benefit of tax credits is factored into the cost of an incremental gas delivery system, the gas can essentially be recovered for free.

5.3.4 Steps 4 and 5: Create a Pro Forma and Assess Economic Feasibility

As with landfill gas power projects, the next steps in the project development process are to create a pro forma and assess economic feasibility. The concepts for analyzing a medium-Btu gas project are the same as those for a power project:

Step 4: **Create a pro forma** that includes a listing of financial assumptions and operating parameters, energy pricing data, calculation of annual expenses and revenues, an income statement, a cash flow statement, and financial results.

Table 5.7 Estimated Cost of Producing Medium-BTU Gas at Example Landfill

Example: Landfill waste in place = 5 million metric tons

Cost Category	Units	Baseload user (continuous)	Heat load user (seasonal)
GAS PRODUCTION COSTS			
Capital Costs (as-spent, 1996 online)			
Total capital requirement	$/MMBtu	6.92	15.56
Incremental capital requirement	$/MMBtu	1.57	3.53
O&M Costs (1996)			
LFG collection system	$/MMBtu	0.31	0.70
Gas delivery system	$/MMBtu	0.02	0.06
Tax Credit (1996)	$/MMBtu	1.049	1.049
FIRST YEAR COST OF GAS (1996)			
Capital charge rate		0.136	0.136
Total Gas Cost			
Levelized capacity price	$/MMBtu	0.94	2.12
1996 O&M price	$/MMBtu	0.34	0.75
Total 1996 cost of gas	$/MMBtu	1.28	2.87
Cost of gas including tax credit	$/MMBtu	0.23	1.82
Incremental Gas Cost (a)			
Levelized capacity price	$/MMBtu	0.21	0.48
1996 O&M price	$/MMBtu	0.02	0.06
Total 1996 cost of gas	$/MMBtu	0.24	0.53
Cost of gas including tax credit	$/MMBtu	(0.81)	(0.51)

Notes:

See Chapter Appendix for notes on these calculations.

(a) Incremental Gas Cost does not include capital and O&M costs associated with LFG collection system.

Step 5: **Assess economic feasibility** based on cash flows, debt coverage ratios, owner's ROR, and NPV of cash flows.

5.4 ALTERNATIVE OPTIONS

Although the conventional power generation option and the medium-Btu gas sales option account for the vast majority of landfill gas energy recovery projects, there are several additional gas use alternatives that may be worth exploring. These alternatives, described briefly below, include: upgrading landfill gas to pipeline quality gas; using landfill gas as a vehicle fuel; using landfill gas in niche applications; and using landfill gas in fuel cells.

5.4.1 Upgrade to Pipeline Quality Gas

Upgrading gas to pipeline quality is relatively expensive, because of substantial processing requirements to remove nitrogen and other constituents of raw landfill gas. This option is currently viable only at larger landfills (i.e., more than 4 million cf per day) where significant economies of scale can be achieved. Landfill gas developers report that the revenues required to support such a project are in the range of $3.62 to $4.14 per MMBtu (1994$) [SCS Engineers, 1994]. Tax credits, such as IRS Section 29 credits, may be available to qualifying projects to help the economics of this type of project. Higher natural gas prices would increase the attractiveness of this option.

Local distribution companies (LDCs) are the best potential market for upgraded gas sales, because they have a large existing market for the gas. The price an LDC will pay for upgraded landfill gas will probably be based on the price it pays for natural gas from producers and gas marketers. There are many different pricing methods used by LDCs. One of the most common is to index the gas price to the monthly market, or "spot," price. Spot prices vary among geographic areas and pipeline systems, and they fluctuate month-to-month. In the last few years, spot prices have been low due to a glut of natural gas supply on the market. Although this glut is disappearing, gas prices are not expected to increase dramatically in the next few years. LDCs may require gas testing for certain constituents, and assurances that these constituents will be removed or kept to a very low level.

5.4.2 Vehicle Fuel Applications

There are a few potential vehicle fuel applications for landfill gas – compressed natural gas (CNG), liquified natural gas, and methanol – that are in the early stages of development or commercialization. At this time, CNG and other alternate-fuel vehicles make up a very small percentage of automobiles in the U.S., so there is not a large demand for CNG as a vehicle fuel. Environmental regulations may increase demand; for example, in southern California and the Northeast, alternate-fuel vehicles are expected to become a way to reduce local ozone pollution. Recent federal regulations may favor methanol produced from a renewable source, such as landfill gas.

Cost savings can be realized for landfill owner/operators who own vehicles or other nearby fleets (e.g., municipal vehicles, delivery trucks) that can be converted to run on alternate fuels. Key factors in the economic evaluation of this option are: (1) the cost of installing a fueling station; and, (2) the costs of retrofitting vehicles to run on the alternate fuel. The cost of installing a compressed landfill gas fueling facility can be significant–the installation of the Puente Hills Landfill fueling station in California cost approximately $1 million [McCord, 1994]. However, under the Energy Policy Act of 1992, a federal tax deduction of up to $100,000 is available for the installation of alternate fueling stations [Webb, 1992; Adkins, 1995]. Vehicle conversion costs, which currently run about $3,500 for passenger vehicles and $4,000 for trucks, can also be offset by tax deductions.[8] Up to $2,000 per vehicle is available for conversions of conventional fuel vehicles and up to $5,000 per vehicle is available for medium-duty fleet purchases or conversions [GRI, 1995].

Fleet vehicles are an especially good application for alternate fuels because these vehicles usually travel less than 200 miles per day and they return to a central location at night for refueling and storage. Also, having a fleet of vehicles will increase fuel usage and therefore decrease average fuel costs, since capital recovery of fueling station construction costs represents the majority of fuel production costs (operation and maintenance costs for alternate fuel vehicle stations are minimal). For example, fuel costs at the Puente Hills CNG station range from 48¢ per gallon gasoline equivalent at a 100 percent station utilization factor to $1.26 per gallon gasoline equivalent at a 25 percent station utilization factor [Wheless, Thalenburg, Wong, 1993].

5.4.3 Fuel Cells

The use of fuel cells to chemically convert landfill gas to electricity is a promising application, largely because of the high efficiency and minimal emissions resulting from this process. At this time, use of fuel cells for landfill gas applications is in the demonstration phase.

The phosphoric acid fuel cell (PAFC) is one of the three types of fuel cells suitable for stationary power production. This technology is considered commercially viable today, for other fuels, and there are over 40 MW of PAFC demonstration units in operation [Swanekamp, 1995]. The capital cost of the PAFC unit is $3,000 per kW for delivery in 1995, and is projected to decrease to approximately $1,500 per kW by 1998 [Strait, Doorn, and Roe]. Variable O&M costs for the units are estimated to be 1.7¢/kWh [FCCG, 1993].

Landfill gas-powered fuel cells are in the demonstration phase. Northeast Utilities installed a test unit at the Flanders Road Landfill in Groton, Connecticut in late 1995, and operation at the site began in June, 1996. Northeast Utilities expected to spend $150,000 to install and maintain the 200 kW fuel cell. [Electric Power Daily, 1995]. Currently, Connecticut Light & Power, a subsidiary of Northeast Utilities, is operating and maintaining the test unit. The $1.5 million, 200-kW PAFC demonstration unit, owned by the EPA, has already been tested at the Penrose Landfill in Sun Valley, CA.

5.4.4 Niche Applications

An important alternative application, particularly for smaller and/or closed landfills, is the local use of landfill gas for niche applications such as heating of greenhouses. Where these applications are available, they may be the most economically attractive for landfills that fail the economic tests of traditional applications. The costs of these applications will vary, depending on type of equipment used. For example, if landfill gas is used in an existing natural gas boiler to heat a greenhouse, costs may be minimal if burner adjustment is all that

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[8] Note that the tax deduction applies to the conversion of vehicles to various alternate fuels (e.g., CNG, LNG, LPG, or methanol).

is required.

Other niche applications are currently being developed, such as the use of landfill gas to produce commercial high purity carbon dioxide (CO_2). With retail prices for this product between $50 and $200 per ton (1992$), this may become a valuable use of landfill gas [Strait, Doorn, and Roe]. The process used to recover landfill gas CO_2 is in the field-scale testing and demonstration phase.

5.5 COMPARISON OF ALL ECONOMICALLY-FEASIBLE OPTIONS

If a landfill owner/operator has the opportunity to produce and sell more than one type of energy product, he or she should compare the net cash flows of each option head-to-head to determine the best option, as illustrated in Figure 5.2. After completing an initial economic analysis for each option, including the development of a pro forma for the most promising options, the owner/operator can compare the results of the economic analysis (Step 5). After ranking the options and selecting an economic winner, the landfill owner/operator should then consider non-price factors including risks, ability to obtain financial backing, environmental performance, and reliability of assumptions. The option that produces the best financial performance while meeting the desired environmental, risk, and operating requirements is the winner.

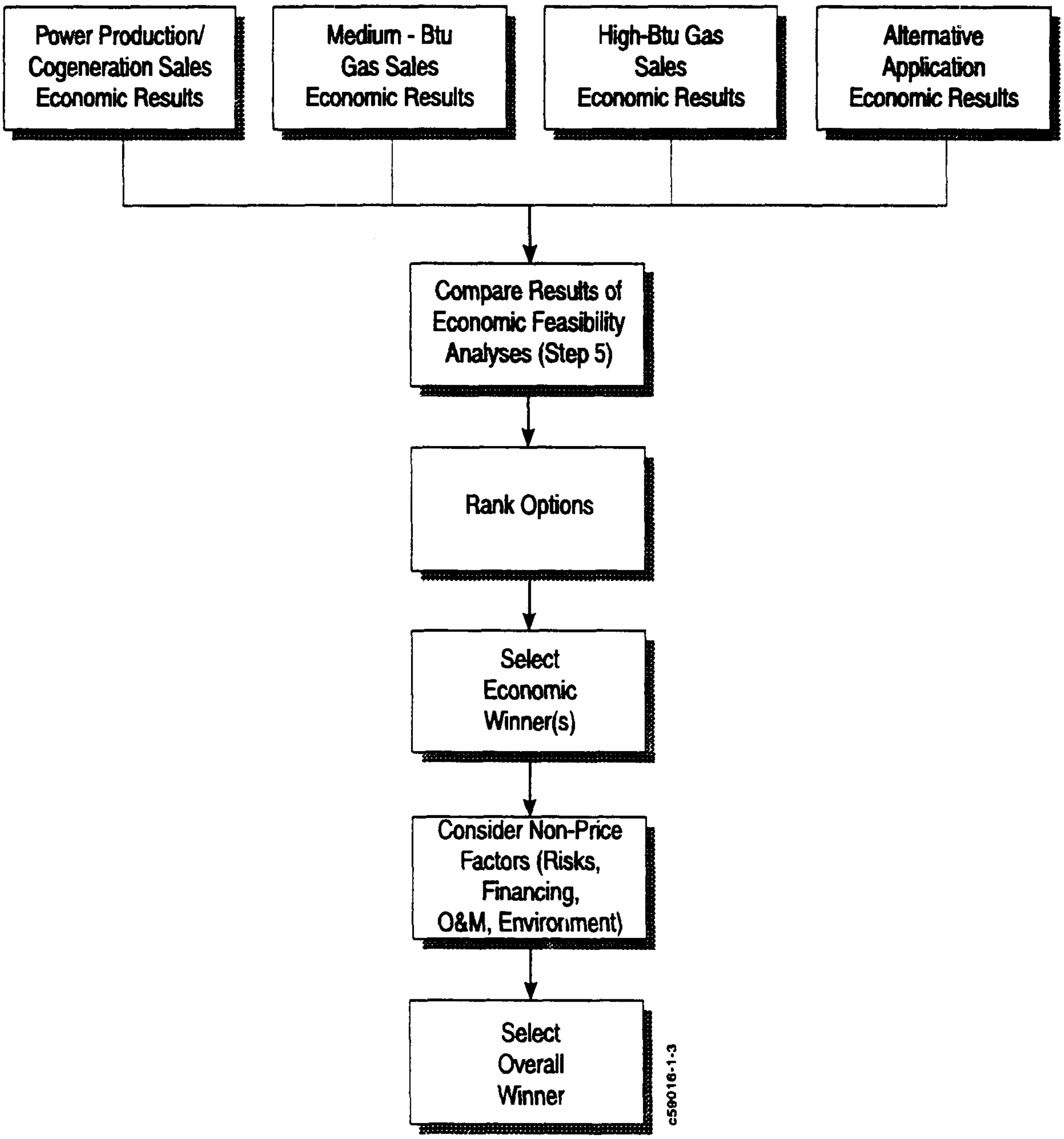
5.5.1 Head-to-Head Economic Comparison

The results of Step 5 of the economic analysis--annual cash flows, NPV, debt coverage, and ROR--can be used independently or together to rank options and select an economic winner. There is no single measure of financial performance that guarantees economic viability, so it is wise to consider several measures together. One approach is to rank options according to the NPV of future after-tax cash flow, making sure that minimum debt coverage and ROR requirements are also met. The option with the highest NPV that meets the minimum debt coverage and rate of return requirements is the economic winner.

5.5.2 Consideration of Non-Price Factors

Although economic feasibility and financial results are important, the final selection of the project technology and configuration should take into account non-price factors such as environmental performance, reliability, and accuracy of assumptions. In the power generation example used above, the IC engine produced the maximum income for the owner, but the use of a CT may still be more attractive if low nitrogen oxide (NO_x) emissions are a priority (see Chapter 9). The permitting process might determine that low NOx emission levels are required, potentially making the IC engine more expensive and/or more difficult to permit than the CT. As another example, a medium-Btu gas sale may show superior economic results when compared to the power generation options, but there may be additional risks entailed in pipeline construction or boiler conversion. Non-price factors have real impacts on project viability and must be taken into consideration.

Figure 5-2 Deciding Among Energy Project Options



6. ASSESSING FINANCING OPTIONS

Financing a landfill gas energy recovery project is one of the most important and challenging tasks facing a landfill owner or project developer. A number of potential financing avenues are available, including finding equity investors, using project finance, and issuing municipal bonds. This chapter provides insights into what lenders and investors look for under each financing method, how to secure financing, and some advantages and disadvantages of each method.

The following six general categories of financing methods may be available to landfill gas projects:

(1) private equity financing
(2) private nonrecourse debt financing (i.e., "project financing")
(3) municipal bond financing
(4) direct municipal funding
(5) lease financing
(6) public financing through institutional or public stock offerings

The Project Development Process

Part I Preliminary Assessment of Project Options
Determining if a Project is Right for Your Landfill
Determining What Project Configuration is Right for Your Landfill

⇓

Part II Detailed Assessment of Project Economics
Evaluating Project Economics
Assessing Financing Options
Selecting a Project Development Partner
Winning/Negotiating an Energy Sales Contract
Securing Project Permits and Approvals
Contracting for EPC and O&M Services

The first four types are common among smaller energy projects such as landfill gas projects. Of the last two types, lease financing is used occasionally and public financing is not commonly used for landfill gas projects, but landfill owners should be aware that they exist. A recent survey of landfill gas energy projects concluded that private debt or equity financing was used in 85% of the cases [Berenyi and Gould, 1994]. The same survey showed that over 10% of the projects were funded directly by city, county, or other municipal revenues.

The selection of financing method is usually driven by cost and applicability, since not all financing methods are available to all types of projects and project owners. A flow chart that illustrates the general process of deciding on the optimal financing method is presented in Figure 6.1. The cost effects of various financing methods are illustrated in Figure 6.2, which shows a sample capacity price for the same project under different financing methods. The capacity price incorporates the cost of building and financing a landfill gas project, annualized over the project life. It is sensitive to interest rates; higher interest rates lead to higher financing costs and a more expensive project compared with a lower interest rate scenario.

From the landfill owner's perspective, often the simplest and lowest cost financing method is to use direct municipal funding through the municipal operating budget. Because

Figure 6-1: Assessing Financing Options

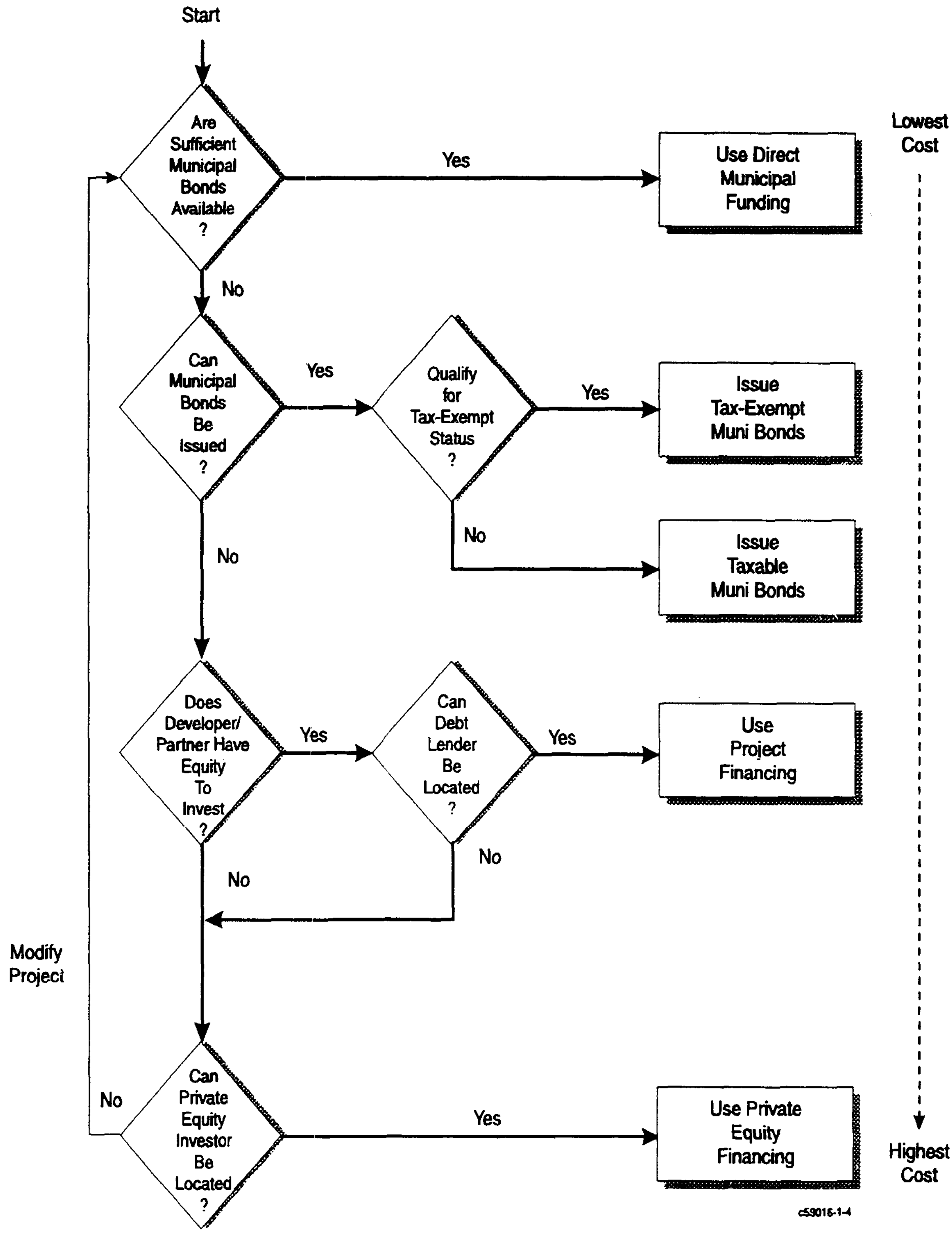
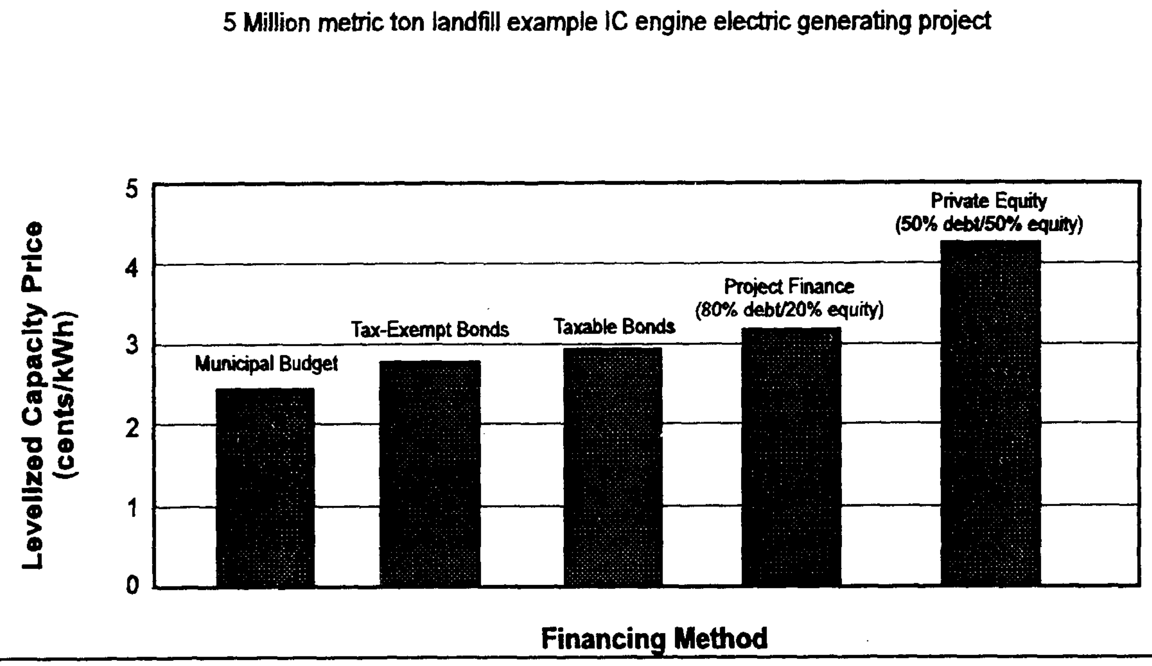


Figure 6-2: Capacity Price Produced by Different Financing Approaches



the amount of municipal funds available is usually limited, however, this method may not be possible for many projects. Issuing municipal bonds is also a low-cost option, particularly for projects owned by a public agency, but local and federal applicability rules must be satisfied in order to use this method. If neither of these options is viable, then the project must look to higher-cost debt or private equity for financing. Selecting a developer with equity to invest or a demonstrated ability to obtain financing for landfill gas projects is a convenient strategy for landfill owners exploring these financing options.

6.1 FINANCING: WHAT LENDERS/INVESTORS LOOK FOR

Most lenders and investors decide whether or not to lend to or invest in a landfill gas project based on the expected financial performance of the project. Financial performance is usually evaluated using a pro forma model of project cash flows (discussed in Chapter 5). Thus, preparing a detailed pro forma is an important step in ensuring the financial feasibility of a landfill gas energy project.

A lender seeking demonstration of project financial strength will usually examine the following measures:

- Debt coverage ratio – The lender's main measure of project financial strength is the ability of a project to adequately meet debt payments. Debt coverage ratio is the ratio of operating income to debt service requirement and is usually calculated on an annual basis. Debt coverage ratios are usually expected to be in the 1.3 to 1.5 range.

- Owner's rate of return (ROR) on equity – The desired ROR currently ranges from about 12% to 18% for most types of power projects. Outside equity investors will typically expect a ROR of 15% to 20% or more, depending mainly on the project risk profile. These RORs reflect early-stage investment situations; investments that are made later in the development or operation phases of the project typically receive lower returns because the risks have been substantially reduced.

The feasibility of a particular landfill gas energy project is also determined by the quality of supporting project contracts and permits, and by risk allocation among project participants. The uncertainties about whether a power project will perform as expected or whether assumptions will match reality are viewed as risks. To the extent possible, the project's costs, revenues, and risk allocation are spelled out through contracts with energy purchasers, equipment suppliers, fuel/landfill gas suppliers, engineering/construction firms, and operating firms, as well as through the presence of permits, developer experience, and financial commitments. Table 6-1 summarizes the principal project risk categories, viewed from the beginning of the development process, and presents possible risk mitigation strategies, the most important of which are usually obtaining contract(s) securing project revenues and verification of landfill gas availability. Potential lenders and investors will look to see how the project developer has addressed each risk through contracts, permitting actions, project structure, or financial strategies.

6.2 Financing Approaches

Capital for landfill gas energy projects is most commonly obtained from private equity financing, project financing, municipal bonds, or direct municipal funds. This section focuses on the lenders' requirements, the means of securing financing, and the advantages and disadvantages of each of the four major financing approaches. Two other potential financing methods – lease financing and public debt financing – are also discussed briefly.

6.2.1 Private Equity Financing

Historically, private equity financing has been one of the most widely used methods of financing landfill gas energy projects. In order to use private equity financing, an investor must be located who is willing to take an ownership position in the landfill gas energy project. In return for a significant share of project ownership, the investor is willing to fund part or all of the project costs using its own equity or privately placed equity or debt. Some landfill gas developers are potential equity investor/partners, as are some equipment vendors, fuel suppliers, and industrial companies. Investment banks are also potential investors. The advantages and disadvantages of private equity financing are presented in Box 6.1. The primary advantage of this method is its availability to most projects; the primary disadvantage is its high cost.

Equity investors typically provide equity or subordinated debt for projects. Equity is invested capital that creates ownership in the project, like a down-payment in a home mortgage. Equity is more expensive than debt, because the equity investor accepts more risk than the debt lender. (Debt lenders usually require that they be paid before project earnings get distributed to equity investors.) Thus the cost of financing with equity is usually significantly higher than financing with debt. Subordinated debt gets repaid after any senior debt lenders are paid and before equity investors are paid. Subordinated debt is sometimes viewed as an equity-equivalent by senior lenders, especially if provided by a credit-worthy equipment vendor or industrial company partner.

Table 6-1 Addressing Landfill Gas Energy Project Risks

Risk Category	Risk Mitigation Measure
Landfill gas availability	• Drill test wells, monitor samples • Hire expert to report on gas availability • Model gas production over time • Execute gas delivery contract/penalties with landfill owner • Provide for back-up fuel if necessary
Construction	• Execute fixed-price turnkey contracts • Include monetary penalties for missing schedule • Establish project acceptance standards, warranties
Equipment performance	• Select proven technology • Design for landfill gas Btu content • Design to take landfill gas impurities into account • Get performance guarantees, warranties from vendor • Include major equipment vendor as partner • Select qualified operator
Environmental permitting	• Obtain permits prior to financing (air, water, building) • Plan for condensate disposal
Community acceptance	• Purchase site, sign lease, execute option agreement • Obtain zoning approvals • Demonstrate community support
Power sales agreement (PSA)	• Have signed PSA with local utility, or industrial plant • Match PSA pricing, escalation to project expenses • Where possible, get capacity payment to cover fixed costs • Get sufficient term to match debt repayment schedule • Confirm interconnection point, access, requirements • Make sure online date is achievable • Include force majeure provisions in PSA
Energy sales agreements	• Match energy pricing and escalation to project costs • Limit liability for interruptions, have back-up • Include industrial firm, fuel company as partner (see PSA items above)
Financial performance	• Create financial pro forma • Calculate cash flows, debt coverages • Commit equity to the project • Ensure robust ROR • Maintain working capital, reserve accounts • Budget for major equipment overhauls

Box 6-1 Private Equity Financing -- Advantages/Disadvantages

Advantages

- For some power projects under 20 MW without access to municipal bonds, this may be the only means of obtaining financing.
- Transaction costs are usually less than with project financing or bond financing.
- Equity partners can often move faster than commercial lending institutions, enabling tight project schedules to be met.
- Bringing in an equity or subordinated debt partner is an effective means of risk-sharing, provided that the risk allocation is reflected in the project structure.

Disadvantages

- Equity is expensive; returns on equity will be paid to the investor out of project cash flows.
- Project owners will have to give up some project ownership and control to an equity investor.
- The addition of a subordinated debt partner can complicate the financing process if project financing is being used.
- A partner who is an equipment vendor, fuel company, or industrial company might have different objectives than the landfill owner (e.g., operation for optimum emissions control may not be a priority).

Investor's Requirements

The equity investor will conduct a thorough due diligence analysis to assess the likely ROR associated with the project. This analysis is similar in scope to banks' analyses, but is often accomplished in much less time because of the entrepreneurial nature of equity investors as compared to institutional lenders. The equity investor's due diligence analysis will typically include a review of contracts, project participants, equity commitments, permitting status, technology and market factors. The key requirement for most pure equity investors is sufficient ROR on their investment. The due diligence analysis, combined with the cost and operating data for the project, will enable the investor to calculate the project's financial performance (e.g., cash flows, ROR) and determine its investment offer based on anticipated returns. An equity investor may be willing to finance up to 100% of the project's installed cost, often with the expectation that additional equity or debt investors will be located later.

Some types of partners that might provide equity or subordinated debt may have unique requirements. Potential partners such as equipment vendors, fuel suppliers, and industrial companies generally expect to realize some benefit other than just cash flow. The desired benefits may include equipment sales, service contracts, tax benefits, and economical and reliable energy supplies. For example, an engine vendor may provide equity or subordinated debt up to the value of the engine equipment, with the expectation of selling out its interest after the project is built. A fuel supplier might also become an equity partner to gain access to a low-cost gas supply, or a nearby industrial company might want to gain access to fuel or derived energy. The requirements imposed by each of these potential investors are sure to include not only an analysis of the technical and financial viability, but also a consideration of the unique objectives of each investor.

Securing Private Equity Financing

To fully explore the possibilities for private equity or subordinated debt financing, landfill owners should ask potential developers if this is a service they can provide. The second most common source of private equity financing is an investment bank that specializes in the private placement of equity and/or debt. Additionally, the equipment vendors, fuel companies, and industrial companies that are involved in the project may also be willing to provide financing for the project, at least through the construction phase. The ability to provide financing is often an important consideration when selecting a developer, equipment vendors, and/or other partners.

6.2.2 Project Finance

"Project finance" is a method for obtaining commercial debt financing for the construction of a facility, where lenders look at the credit-worthiness of the facility to ensure debt repayment rather than at the assets of the developer/sponsor. In most project finance cases, lenders will provide project debt for up to about 80% of the facility's installed cost and accept a debt repayment schedule over 8 to 15 years. Project finance usually provides the option of either a fixed rate loan or a floating rate loan, which is tied to an accepted interest rate index (e.g., U.S. treasury bills, London Interbank rate). Typically, the facility sponsor(s) will set up a separate subsidiary company to develop and manage the facility, and lenders in effect provide financing to the subsidiary company with limited or no recourse to the subsidiary's parent(s). Thus project financing is often known as "nonrecourse" financing because the project debt is secured by facility assets and contracts, with no recourse (or limited recourse) to parent companies should the facility experience financial under-performance or failure.

Most private power projects, especially those built in the last 15 years by third-party developers, were completed using project finance. The major advantages and disadvantages of project finance are listed in Box 6.2. The biggest advantage of project finance is the ability to use others' funds for financing, without giving up ownership control. The biggest disadvantages are the difficulty of obtaining project finance for landfill gas projects, which tend to be smaller than traditional power projects. In addition, project finance transactions are costly and often an onerous process of satisfying lenders' criteria.

Lenders' Requirements

In deciding whether or not to provide project finance to a power project, lenders examine not only the expected financial performance of the project; they also consider several other factors that underlie facility success such as contracts, project participants, equity stake, permits, technology, and sometimes market factors. A good candidate for project financing should have most, if not all, of the following:

Box 6-2 Project Finance – Advantages/Disadvantages

Advantages

- Project debt is usually nonrecourse to the landfill owner and/or energy project sponsor; however, the owner and sponsor remain liable for explicit warranties and misrepresentations.
- The project debt can usually be kept off the project sponsor's balance sheet.
- Project sponsors can retain sole or majority ownership of the landfill energy project.

Disadvantages

- The small capital requirements of landfill gas projects relative to other power projects can make project financing difficult to obtain, because transaction costs and risk perceptions remain high.
- Lenders usually require most key contracts and permits to be in place on or before financial closing, which adds to project lead time.
- Lenders may place other requirements on the project such as minimum equity contribution, minimum debt coverage, and creation of a major maintenance fund.
- Debt must usually be repaid over an 8 to 15 year term.

- Signed energy sales agreement from a credit-worthy electricity or gas customer (e.g., utility, industrial, municipality)
- Fixed-price agreement with engineering/construction firm(s)
- Equity commitment
- Operation and maintenance agreement
- Fuel supply analysis and supply/transport agreement(s)
- Control of the project site (e.g., option agreement or ownership)
- Environmental permits
- Local permits/approval

In addition, lenders may place additional requirements on the project developers such as maintaining a certain minimum debt coverage ratio and making regular contributions to an equipment maintenance account, which will be used to fund major equipment overhauls.

In addition, in cases where project finance is used, lenders generally expect the project sponsors to make some equity commitment of their own. An equity commitment shows that project sponsors also have a financial stake in project success, and it implies that sponsors will be more likely to step in with additional funds if problems arise. The expected debt-equity ratio is usually a function of project risks. In the mid-1980s, some power projects obtained project financing with little or no equity contribution, based mainly on the financial strength of the project and supporting contracts. However, most lenders now do not accept such highly leveraged projects and instead require at least a 20% equity stake on the part of project sponsor(s).

Securing Project Financing

Landfill gas projects have historically experienced some difficulty securing project financing, because of their relatively small size and the perceived risks associated with the technology. In addition, the transaction costs for arranging project financing are relatively high, owing to the lender's extensive due diligence (i.e., financial and risk investigation) requirements; it is often said that the transaction costs may be the same for a 10 MW project as for a 100 MW project. For this reason, most of the project finance groups at the large commercial banks and investment houses hesitate to lend to projects with capital requirements less than about $20 million (or a 20 MW or larger power project).

The best opportunities for landfill gas projects to secure project financing are generally with the project finance groups at smaller investment capital companies and banks, or at one of several energy investment funds that commonly finance smaller projects. Some of these lenders have experience with landfill gas projects and may also be attuned to the unique needs of smaller projects. Depending on the project economics, some investment capital companies and energy funds may consider becoming an equity partner in the landfill gas project in addition to, or instead of, providing debt financing. Additionally, it is worth contacting local and regional commercial banks. Some of these banks have a history of providing debt financing for small energy projects, and may be willing to provide project financing to a "bundle" of two or more landfill gas projects.

6.2.3 Municipal Bond Financing

Municipally owned landfills occasionally issue tax-preferred municipal bonds to finance landfill gas energy projects. The biggest benefit of using this financing method is that the resulting debt has an interest rate that is often 1% to 2% below commercial debt or taxable bond debt (see Box 6.3). For a bond issue to qualify for tax-exempt status, a number of complex IRS conditions concerning project ownership and purpose must be met. Additionally, state-specific laws and policies may also impact the ability to issue tax-exempt bonds. Since the rules governing the applicability of tax-exempt bond financing are complex, it is wise to consult the IRS tax code and a tax expert before deciding on a particular approach.

The important factors in qualifying for and obtaining municipal bond financing are described below.

Lenders' Requirements

Generally speaking, a government entity (e.g., municipality, public utility district, county government) can issue either tax-exempt governmental bonds or private activity bonds, which can be either taxable or tax-exempt. Bonds can either be secured by general government revenues (i.e., revenue bonds), or by the specific revenues from the energy project (i.e., project bonds). The term for bond financing usually does not exceed the useful life of the facility; terms extending up to 30 years are not uncommon, however.

In addition to initial qualification requirements, many tax-exempt bond issuers find that strict debt coverage and cash reserve requirements must be imposed on an energy project to

Box 6-3 Municipal Bond Financing – Advantages/Disadvantages

Advantages

- Tax exempt financing provides access to debt at interest rates that are 1% to 2% below the rates offered by commercial lenders.
- Debt repayment can be extended over the life of the facility, which may be 20 years or more.

Disadvantages

- The financial performance requirements (e.g., debt coverage, cash reserves) placed on the project by the bond issuer may exceed project finance lender's requirements.
- Public disclosure requirements exist.
- The project may have to contend with state caps on the amount of private activity bonds that can be issued.
- It is difficult to obtain additional capital for the project in cases where the design, equipment, or other conditions change.

ensure that the financial stability of the issuer is preserved. These requirements may be even more rigorous than those imposed by commercial banks under a project finance approach.

Securing Municipal Bond Financing

To qualify for a governmental bond issue, a project must meet at least two criteria:

(1) Private business use test – No more than 10% of the bond proceeds are to be used in the business of an entity other than a state or local government.

(2) Private security of payment test – No more than 10% of the payment of principal or interest on the bonds can be directly or indirectly secured by property used for private business use.

Under these rules, a government entity could issue tax-exempt governmental bonds to finance a landfill gas energy project if the project would be owned and operated by the same government entity. If private owners or operators are involved, however, the project may not qualify for tax-exempt governmental bond status [Snohomish, 1994; Martin, 1993]. Private business use can include private ownership of all or part of a landfill gas project.

If a particular project fails to qualify for a governmental bond issue, it may still achieve tax-exempt bond status through one of several exemptions for projects that provide some form of public benefit. Among these exemptions are at least two that could apply to certain landfill gas projects with partial private ownership [Kulakowski, 1994; Martin, 1993]:

Local furnishing of electricity – Tax-exempt status is provided for a power project that sells electricity to a utility (public or investor-owned) that is a net importer of power and serves no more than two contiguous counties or one county and one contiguous city. It is unclear whether or not the financing for the landfill gas extraction/collection portion of the project can be included in this exemption.

Local district heating and cooling – Tax-exempt status is provided for an energy project that sells steam, chilled water, and/or other thermal energy to two or more unrelated entities, which must be within two counties. The exemption covers the equipment used to generate the thermal energy.

Two additional exemptions may be applicable to landfill gas projects, although it is unknown whether any landfill gas projects have successfully used these exemptions:

Prepayment of fuel supply – Tax-exempt status is provided for a governmental entity that purchases a long-term fuel supply such as gas reserves. Tax-exempt status covers only the purchase of fuel supplies that are used in electric generation which serves a governmental entity.

Solid waste disposal – Tax-exempt status is provided for facilities that burn solid waste fuel that has no market value as a saleable product.

The mechanics of issuing municipal bonds vary according to the type of bond, method of qualification, and the state or municipality in which the bond is issued. Qualified local tax or financial experts should be consulted for guidance.

6.2.4 Direct Municipal Funding

Landfill gas energy recovery projects can also be funded directly through the operating budget of a city, county, landfill authority, or other municipal government. Using this method, the costs of project development, equipment, and installation are expensed directly from the municipal budget, thus eliminating the need for outside financing or partnering. Typically this method is used to fund small projects that fit within the municipality's budget capabilities and priorities. Advantages and disadvantages are described in Box 6.4.

6.2.5 Lease Financing

Lease financing encompasses several leasing strategies in which the project operator/equipment user leases part or all of the energy project assets from the asset owner(s). Typically, lease arrangements provide the advantage of enabling the transfer of tax benefits such as accelerated depreciation or energy tax credits to an entity that can best use them. Lease arrangements commonly provide the lessee with the option, at predetermined time intervals, to purchase the assets or extend the lease. Several large equipment vendors have subsidiaries that lease equipment, as do some financing companies. There are several variations on the lease concept including:

Leveraged Lease – In a leveraged lease, the equipment user leases the equipment from the owner, who finances the equipment purchase with external debt and possibly equity.

Box 6-4 Direct Municipal Funding – Advantages/Disadvantages

Advantages

- The need to meet tough lender's requirements (e.g., debt coverage, equity input, credit-worthiness, contracts in place) is eliminated, although any municipal funding criteria must still be met.

- Expensing the project's funding requirements directly from the municipal budget will eliminate interest charges on project debt, making this generally the lowest-cost financing method.

- The project is not subject to delays caused by lenders' time requirements for evaluating the project and setting up the financing.

Disadvantages

- Usually the amount of municipal funds are limited, thus limiting the size of the project.

- The municipality loses the opportunity to share risks with other project partners.

- A public approval process may be required, making the project vulnerable to political forces.

Sale-Leaseback – In a sale-leaseback, the equipment user buys the equipment, then sells it to a corporation, which then leases it back to the user under contract.

Some of the disadvantages of lease financing include accounting and liability complexities, as well as the loss of tax benefits by the project operator/user.

6.2.6 Public Debt Financing

Financing power projects with public debt such as secured notes and bonds offered to institutional investors has recently received much attention from developers of large, conventional-fueled power projects. This approach is not likely to be an option for the typical landfill gas project, however, unless several high-quality landfill gas projects can be "packaged" together under single ownership. In this case, the debt could be raised for the package of projects through a single offering, and due diligence costs would be minimized by standardizing the projects. In order to qualify for public debt financing, a project must be rated at or near investment grade by rating agencies, have solid supporting contracts, and be large enough – approximately $100 million or more – to offset the transaction costs.

6.3 CAPITAL COST EFFECTS OF FINANCING ALTERNATIVES

Each financing method produces a different weighted cost of capital, which affects the amount of money that is spent to pay for a landfill gas power project and the price that is needed to cover project costs. The weighted cost of capital is dependent on the share of project funds financed with debt and equity, and on the cost of that debt or equity (i.e., interest rate on debt, ROR on equity). For example, in a project finance scenario with a debt/equity ratio of 80/20, an interest rate on debt of 9%, and an expected ROR on equity cf 15%, the weighted cost of capital is 10.2%. Decreasing the amount of debt to 70% means that more of the project funds must be financed with equity, which carries a higher interest rate than debt, so the weighted cost of capital becomes 10.8%. Increasing the weighted cost of capital means that project revenues must be increased to pay the added financing charges. In contrast a lower weighted cost of capital lessens the amount of money spent on financing charges, which makes the project more competitive.

Among the four main financing methods presented above, direct municipal funding usually produces the lowest financing costs over time, while private equity financing produces the highest. Generally speaking, the four financing methods are ranked from lowest cost to highest cost as follows:

1) Direct municipal funding
2) Municipal bond financing
3) Project financing
4) Private equity financing

The advantage associated with direct municipal funding is created by the elimination of interest on debt, and by the low expected ROR. Municipal bond financing achieves its advantage through access to low-interest debt – assumed to be currently about 6.5% for tax-exempt bonds and 8.25% for taxable bonds [Snohomish, 1994]. Project finance produces a higher capacity price because funds are required to pay interest charges as well as ROR on equity (assumed to be 15%). Finally, private equity is the most expensive because it usually demands a higher ROR (assumed to be 18%) on equity than project finance, and equity makes up a larger share of the capital requirement.

Interest rates are an important determinant of project cost if the project sponsor decides to borrow funds, either through lending institutions or bond offerings, to finance the project. For example, raising interest rates by 1% would cause an increase of about 2% to 3% in the cost of generating electricity from a landfill gas project. Interest rates are determined by the prevailing rate indicators at a particular time, as well as by the project and lender's risk profiles. The interest rate for fixed-rate nonrecourse debt is usually determined by the lender's "spread" over an index such as U.S. treasuries. Likewise, the interest rate for floating-rate nonrecourse debt is based on a spread above variable indices such as the prime rate or the London Interbank Offered Rate (LIBOR). The lender's spread varies widely, but a landfill gas project with reliable gas availability, experienced participants, and a strong power purchase contract might expect a spread of 2.0% to 2.75% above the index. [Seifullin, 1995; DePrinzio, 1995]. Smaller projects requiring less than roughly $5 million of nonrecourse debt could also expect to pay an interest rate premium to compensate the lender for disproportionate transaction costs.

Table 6-2 illustrates the economic impact of different financing methods for the 5 million metric ton landfill example described in Chapter 5, which showed an IC engine power project with a capital cost of $1,675/kW. As Table 6-2 indicates, the levelized capacity price is more than doubled when comparing the low-cost municipal budget method with the high-cost private equity method (20% debt and 80% equity). [The capacity price refers to the initial cost of financing and building the project, levelized over the project life. This is the interest rate-sensitive portion of the project cost. Note that O&M and royalty expenses must be added, as described in Chapter 5, to determine the total project cost.] The more common private equity structure is the 50% debt case, and the more common project finance structure is the 80% debt case.

Table 6-2 Capital Cost Effects of Financing Approaches

Case: 5 million metric ton landfill (waste-in-place)
5 MW IC engine electric generating project

Installed Capital Requirement: 1,675 $/kW
Annual full load operating hours 7,008

Financing Method	Interest Rate on Debt	After-tax Return on Equity	Weighted Cost of Capital	Capital Charge Rate	Levelized Capacity Price Required (¢/kWh)[a]
Private Equity Financing					
20% Debt/80% Equity	9.00%	18%	16.20%	0.225	5.38
50% Debt/50% Equity	9.00%	18%	13.50%	0.182	4.35
Project Finance					
70% Debt/30% Equity	9.00%	15%	10.80%	0.145	3.47
80% Debt/20% Equity	9.00%	15%	10.20%	0.136	3.25
Municipal Bond Funding					
Taxable Bond	8.25%	NA	8.25%	0.124	2.96
Tax-Exempt Bond	6.50%	NA	6.50%	0.111	2.65
Municipal Budget	NA	5%	5.00%	0.100	2.39

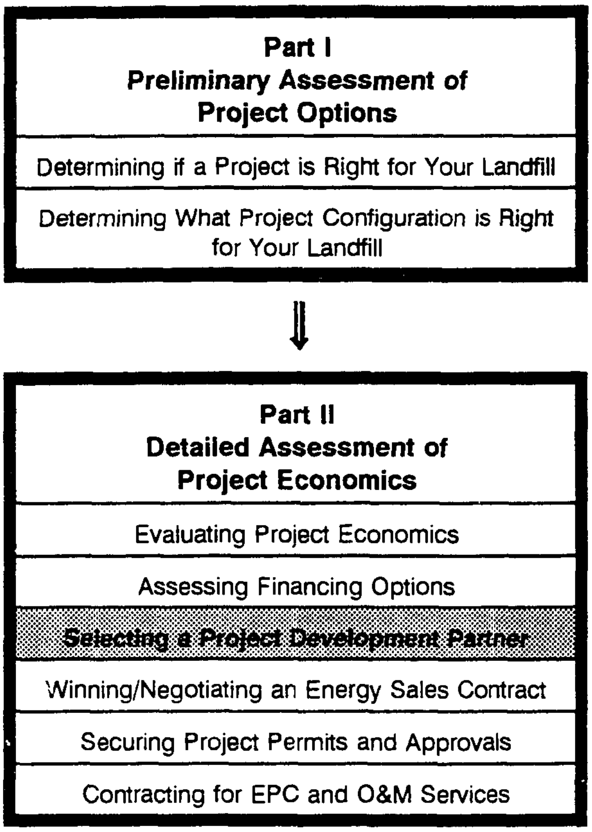
Notes:
[a] Levelized Capacity Price (¢/kWh) =
(Installed Capital Requirement) x (Cap Charge Rate)/(Annual hours)

This price only represents the capital cost portion of the project; other expenses such as O&M and royalties must be added to get to a total project cost.

7. SELECTING A PROJECT DEVELOPMENT PARTNER

The selection of a project development partner is a critical decision because the landfill owner often relies on the developer to manage the process of transforming a landfill energy project from a feasible idea on paper into a functioning, multi-million dollar facility. Some landfill owners have the expertise, resources, and desire to lead the development effort on their own, but even in this case, choosing the right development partner(s) can greatly improve the likelihood of project success. This chapter provides guidance to landfill owners who are attempting to determine: (1) the role that they might take in the development process; and (2) the right partner to get the project developed, financed, and built.

The Project Development Process



From the landfill owner's perspective, there are three general ways to structure the development and ownership of a landfill gas energy project:

(1) Develop the project internally – Landfill owner manages the development effort and maintains ownership control of the project. This approach maximizes economic returns to the owner, but also places most of the project risks on the owner (e.g., construction, equipment performance, financial performance).

(2) Team with a pure project developer – Landfill owner selects a qualified developer to develop and build the project. This option shifts most risks onto the developer, but the landfill owner usually gives up control, ownership rights, and some or all of the potential for financial returns. A variation on this option is selecting a developer to provide the landfill owner with a "turnkey" plant, which is built by the developer but owned by the landfill owner.

(3) Team with a partner – Landfill owner teams with an equipment vendor, engineering/procurement/construction (EPC) firm, industrial company, or fuel company to develop the project and to share the risks and financial returns.

With these structures in mind, a landfill owner can determine his or her desired role in the project development process by considering two key questions:

- Should the landfill owner self-develop or find a partner?

- If a partner is desired, what kind of partner best complements the landfill owner and the project?

The landfill owner can answer the first question by conducting a frank examination of his or her own expertise, objectives, and resources. The second question is more complicated because it entails an assessment of the landfill owner's specific needs and a search for the right partner to complement those needs.

Figure 7.1 illustrates the process of determining the best development approach. As it indicates, in cases where the landfill owner wants to be involved in the project development process, a number of issues must be considered. These issues are discussed in the following sections.

7.1 THE PARTNER/NO PARTNER DECISION

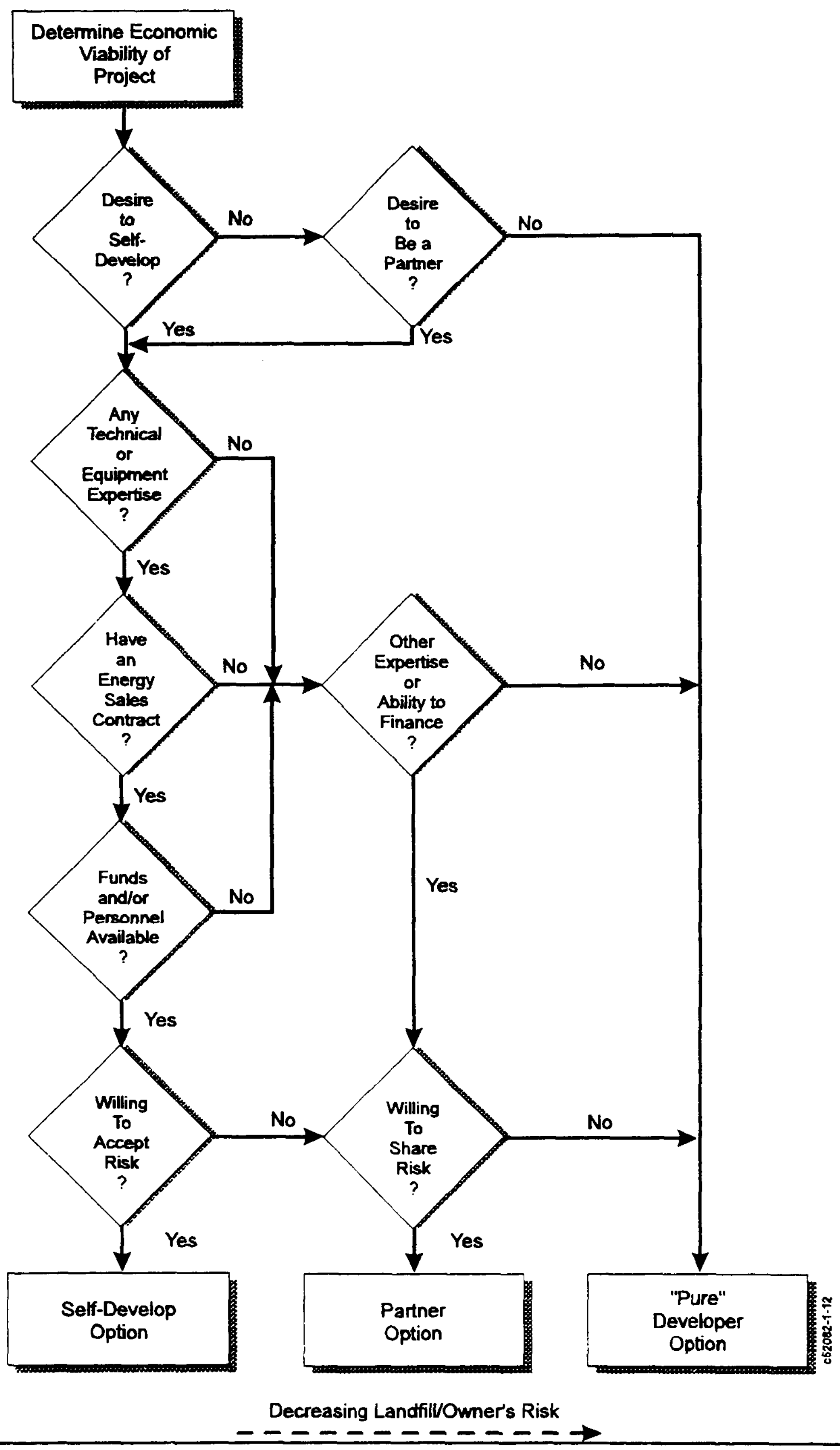
Before deciding whether to develop the project internally, the landfill owner must understand the role of the project developer, which is outlined in Box 7.1. Next, an assessment of the landfill owner's objectives, expertise, and resources will determine whether or not the owner should undertake project development independently or include a partner/developer. A landfill owner who is a good candidate for developing a project alone will have many of the following attributes:

- strong desire to develop a successful, profitable energy project;
- willingness to accept project risks (e.g., construction, equipment, permitting, financial performance);
- expertise with technical projects (e.g., power, infrastructure, or industrial) or energy equipment;
- high confidence level regarding landfill gas quantity and quality (i.e., modeling or test wells have been completed);
- possession of a power sales agreement with a local electric utility, an electric consumer, a gas purchaser, or sufficient internal demand; and
- funds and personnel available to commit to the development process.

In addition, other attributes may improve a landfill owner's likelihood of success in developing a project in-house. Ownership or control of multiple landfills, for example, may be desirable because it will enable the owner to leverage his/her time and resources spent. Similarly, a strong desire for new business opportunities and/or visibility may be beneficial. An example of the type of landfill owner that fits this profile is a municipal utility district that might have responsibility for local electricity procurement and distribution, water supply, and/or sewage treatment, in addition to landfill management.

If the landfill owner is uncertain about several of the attributes listed above, particularly the desire to develop, the willingness to take significant risks, and/or their level of technical

Figure 7.1 The Developer/Partner Selection Process



Box 7.1 The Role of the Project Developer

Determine Landfill Gas Supply – If the landfill owner has not already completed this step, then the first development step will be to determine the landfill gas supply using calculations, computer modeling, and/or test wells.

Scope Out the Project – Project scoping includes early-stage tasks such as selecting a location for the equipment, sizing the energy output to the landfill gas supply, contacting potential energy customers, and selecting key equipment.

Conduct Feasibility Analysis – Feasibility analysis includes detailed technical and economic calculations to demonstrate the technical feasibility of the project and estimate project revenues and costs.

Select Equipment – Based on the results of the feasibility analysis, primary equipment is selected and vendors are contacted to assess price, performance, schedule, and guarantees.

Create a Financial Pro Forma – A financial pro forma is usually created to model the cash flows of a project and to predict financial performance.

Prepare the Bid – If the project must bid in a utility solicitation in order to obtain a power sales agreement (PSA), a responsive bid package will be prepared and submitted.

Negotiate the Power Sales Agreement (PSA) – The terms of the PSA must be negotiated with the purchasing electric utility.

Negotiate the Gas or Steam Sales Agreements – For projects that intend to sell landfill gas or steam, agreements must be negotiated with the energy customers.

Obtain Environmental and Site Permits – All required environmental permits and site permits/licenses must be acquired.

Gain Regulatory Approval – Some power projects must obtain approval from state regulators or certification by the Federal Energy Regulatory Commission (FERC).

Negotiate Partnership Agreement(s) – If project ownership is to be shared with partners or investors, then the project will require negotiation of ownership agreements.

Secure Financing – Securing financing for the project is a critical task that requires specific expertise, depending on the type of financing being used.

Contract with Engineering, Construction, Operating Firms – Firms must be selected and contracts and terms negotiated.

expertise, then he or she might instead choose a partner. The following are several good reasons to develop the project with a partner:

- limited desire to lead the development effort;
- limited technical resources and/or experience;
- need to share or avoid specific project risks;
- difficulty financing the project alone;
- inability to dedicate personnel or time to the development effort;
- project development outside the scope of organizational charter; and
- difficulty spending funds to determine landfill gas quantity.

The questions in Figure 7.1 illustrate other critical considerations in making the partner/no partner decision.

Most landfill owners choose to bring in a developer to build and/or own the energy recovery project, either alone or in partnership with the landfill owner or others. A recent survey of existing and planned landfill gas energy recovery projects shows that about 78% of gas collection systems and 88% of gas processing/energy recovery systems are owned by private firms or in partnership with private firms [Berenyi and Gould, 1994].

7.2 SELECTING A DEVELOPMENT PARTNER

Once the decision has been made to include a project development partner, the next step is to decide what type of partner to select. There are several different types of development partners to choose from, so the landfill owner should look for a partner that provides the best match for the specific energy project and the landfill owner's in-house capabilities. Five general types of project development partners, listed in order of decreasing scope of services, include:

Pure Developer – A firm primarily in the business of developing, owning, and/or operating landfill gas energy projects. Some developers focus on landfill gas power projects, while others may be involved in a broad project portfolio of technologies and fuel types. Pure developers usually will own the completed landfill gas energy facility, but sometimes a developer will build a turnkey facility for the landfill owner.

Equipment Vendor – A firm primarily in the business of selling power or energy equipment, although it will participate in project development and/or ownership in specific situations where its equipment is being used. The primary objective of this type of developer is to help facilitate purchases of its equipment and services.

EPC Firm – A firm primarily engaged in providing engineering, procurement, and construction services. Some EPC firms have project development groups that develop energy projects and/or take an ownership position.

Fuel Company – A firm primarily engaged in providing fuels and/or fuel procurement services. These firms may have project development subsidiaries or agree to take a specific development role such as securing a customer for the landfill gas.

Industrial Company – A firm primarily engaged in manufacturing a product and managing an industrial manufacturing facility. Some industrial firms have power project development subsidiaries or may take a specific role such as guaranteeing energy purchases or assisting with financing.

Ideally, a developer or partner can be identified that fills specific project needs such as ability to secure a power purchase contract, finance the project, or supply equipment. Issuing a request for proposals (RFP) is often a good way to attract and evaluate partners.

A partner reduces risks to the landfill owner by bearing or sharing the responsibilities of project development, although the amount of risk reduction provided depends on the type of partner chosen. For example, a "pure developer" partner will usually take the risk/responsibility of construction, equipment performance, environmental permitting, community acceptance, energy sales agreements, and financing, whereas an equipment vendor partner may only bear the risks of equipment performance.

7.2.1 Selecting a Pure Developer

Selecting a pure project developer to manage the development process and own the landfill gas energy project is a good way for the landfill owner to shed development responsibility and risks, and get the project built at no net cost to the landfill. In addition, the pure project developer typically provides the landfill owner with the strongest development skills and experience, since pure developers focus exclusively on landfill gas projects. Other reasons for selecting a pure project developer include:

- the developer's skills and experience may be invaluable in bringing a successful project online;
- some developers are ready to invest equity or have access to financing; and
- the developer might be in possession of a power sales agreement that was previously won and/or negotiated with a nearby electric utility.

In return for accepting project risks, most developers require a significant share of project profits, potentially up to 100 percent. As a result, the landfill owner generally loses control and ownership of the energy project. Such an ownership arrangement may be appropriate for a particular landfill if, for example, development of an energy recovery system is the lowest cost method for complying with environmental regulations. It may also be necessary to involve a developer in order to take advantage of IRS Section 29 tax credits (see Chapter 5 for more on tax credits). If the developer becomes the sole or controlling owner, however, he/she will tend to make decisions to protect his/her interest in the project, namely the energy revenues, and may be less concerned with the landfill owner's priorities such as controlling landfill gas migration.

The case of the I-95 Landfill in Lorton, Virginia illustrates the key issues involved in taking the pure developer approach. As described in Box 7.2, this landfill partnered with a pure developer to develop a successful energy recovery project. By carefully structuring its

Box 7.2 Developer Selection at I-95 Landfill

The I-95 Landfill Project in Lorton, Virginia illustrates one landfill owner's successful experience in selecting a project developer. The I-95 Landfill Project is a 17.5 million ton sanitary landfill that supports a 6,400-kw electric generating system, using 8 Caterpillar internal combustion engines. The landfill gas collection system is owned and operated by Fairfax County and the electric generating equipment is owned by Landfill Energy Systems, a division of Michigan Cogeneration Systems.

Fairfax County found that selecting a pure developer resulted in the successful completion of the landfill gas power project. Fairfax County hired a consultant to assess the landfill gas quantity and quality, then issued a request for proposals (RFP) to select a project developer. The developer ultimately selected to build the project had experience with other landfill gas projects, a power sales agreement with the local utility, and the ability to finance the project.

A thoughtful contracting approach eliminated potential conflicts between the developer and landfill owner. Fairfax County was most concerned with controlling landfill gas migration and emissions, while the developer wanted to optimize gas output for power generation. The two parties recognized that the best gas collection strategy for minimizing gas migration is often different from the strategy that maximizes power output. In a worst case scenario where an uncooperative developer owns the gas collection system, a landfill owner might be forced to drill collection wells at the landfill perimeter to control offsite migration, which could draw gas away from the developer's collection wells. To avoid this potential scenario, Fairfax County opted to keep control of the entire collection system and now supplies landfill gas to Landfill Energy Systems' electric generating equipment.

contract with the developer, the landfill owner was able to ensure that safety and other concerns were given top priority by the developer.

Arranging for a turnkey project represents a variation on the pure developer approach. The turnkey option is a good approach if the landfill owner wants to retain energy project ownership or the project's return on investment does not meet the developer's criterion. In a turnkey approach, the developer assumes development responsibility and construction risk, finances and builds the facility, and then transfers ownership to the landfill owner when the facility is complete and performing up to specifications. In return, the developer can receive a fee, a share of project proceeds, gas rights, and/or a long-term operation and maintenance contract. Sometimes the landfill owner will use municipal bonds to finance the project, so the developer essentially develops and builds the project for a fee. The turnkey approach enables each entity to contribute what it does best: the developer accepts development, construction, and performance risk; and the owner accepts financial performance risk.

7.2.2 Selecting a Partner (Equipment Vendor, EPC Firm, Fuel Firm, Industrial)

Selecting a development partner who is not a pure developer is a good choice if two key conditions exist:

(1) The landfill owner wants to keep management control of the project and has sufficient in-house expertise and resources to do so; and,

(2) The partner can fulfill a specific role or provide equipment for the project.

In this case, the landfill owner must have a clear desire to manage the development process and should have sufficient technical experience, personnel, and development funds to support the development effort. The owner should also have a relatively high confidence level regarding landfill gas production capability, as well as a willingness to accept a significant share of the project's risks (e.g., financial, environmental permitting, community acceptance). Other factors that could make the partnering approach an appropriate choice include the ownership of a power or energy purchase agreement, or control of multiple landfills that could each be developed into a landfill gas project, thus leveraging the time and resources invested.

There are four basic types of firms that enter into partnership agreements with landfill operators: equipment vendors, EPC firms, fuel suppliers, and industrial companies. Each of these firms have different strengths and will assume different types of project risk. The key characteristics of these types of firms are summarized below.

Equipment vendors: Some equipment vendors such as engine and turbine manufacturers become partners in energy projects, including landfill gas projects, as a way to support the sale of equipment and services to potential customers. Equipment vendors may assist in financing the project, and are often willing to accept the equipment performance risk over a specified length of time for the equipment that they provide. However, equipment vendors typically do not take on responsibilities beyond their equipment services, and they generally want to sell their interest in a project as quickly as possible after the project has been built.

EPC firms: Similarly, some of the larger EPC firms will become partners in power projects with the objective of selling services and gaining a return on equity and/or time invested. However, this type of potential partner tends primarily to pursue large fossil-fueled projects where the EPC's strength as a manager of large, complex projects is more valuable.

Fuel suppliers: A fuel supplier or marketing company can be a potential development partner in landfill gas projects where marketable gas is the energy product for sale. For example, a local natural gas distribution company might become a partner to gain access to a local, low cost gas supply. This type of partner would typically take a very limited role such as guaranteeing a market for the landfill gas or owning the gas collection and processing systems. However, several natural gas suppliers and pipeline companies also have power project development subsidiaries that resemble pure developers in terms of experience and capabilities, and that may be willing to take on a larger role in the project.

Industrial companies: Finally, an industrial company might become a partner in the landfill gas project if it has significant use for the landfill gas or derived energy (i.e., electricity, steam). The industrial company is likely to prefer a limited involvement in the development process.

7.3 Evaluating Individual Firms

Once the right partnering strategy has been identified, the landfill owner should review the capabilities of individual firms that meet the owner's general needs. When selecting a firm to become a development partner, there are several qualities and capabilities that landfill owners should look for, including:

- previous landfill gas project experience;
- a successful energy project track record;
- access to capital and/or financing; and
- in-house resources (e.g., engineering, finance, operation) including experience with environmental permitting and community issues.

Information about individual firm qualifications can be gained from annual reports, brochures, and project descriptions, as well as from discussions with references, other landfill owners, and engineers. Potential warning signs include lawsuits, disputes with landfill owners, and failed projects, although a few failed development efforts and/or underperforming projects can normally be found in the portfolio of any project developer. Published information can be obtained by researching trade literature, through legal information services, and through computer research services.

7.3.1 Issuing a Request for Proposals (RFP)

A landfill owner may find it advantageous to issue an RFP for a developer or partner, because if the RFP is prepared correctly, respondents will generally offer creative, informative, and useful responses. The RFP process is a good way to screen proposals and focus on the best one(s) for further discussions and negotiation.

A landfill owner who plans on issuing an RFP should carefully examine his needs and ask respondents to propose ways to meet those needs or solve problems. For example, if a landfill gas energy project needs a power sales agreement or energy sales contract, then the landfill owner should state in the RFP that the ability to secure one of these agreements is a central selection criterion. Likewise, if ability to secure financing or environmental permits is important, that should also be stated in the RFP. In this way, respondents will be encouraged to offer innovative proposals that meet the project's specific needs.

In general, RFP respondents should be asked to provide the following information:

- Description of the energy project and available options;
- Scope of services being offered (e.g., developer, owner, operator);
- Project development history and performance;
- Pricing and escalation (e.g., royalties/payments to landfill owner, electricity price, energy prices) including buyout price and terms;
- Turnkey facility bid (if appropriate);

- Plan for obtaining energy revenues (e.g., PSA with utility, gas sales contract, steam contract);

- Technology description and performance data;

- Well placement strategy (if applicable);

- Well field operations responsibility;

- Responsibility for environmental compliance;

- Environmental permitting and community approval plan;

- Financing plan;

- Schedule; and

- Operation and Maintenance plan.

Landfill owners should state in the RFP that the owner reserves the right to select none, one, or several respondents for further negotiation, depending on the proposal's responsiveness to the owner's criteria. Appendix D contains a sample RFP that was issued by one landfill. This particular RFP is not very detailed; therefore, the respondent would have some leeway in preparing his or her bid package.

7.3.2 Preparing a Contract

Once the partner has been selected, the terms of the partnership should be formalized in a contract. The contract should accomplish several objectives, including allocating risk among project participants. Some of the key elements of a partnership contract are listed in Box 7.3.

As Box 7.3 indicates, contracting with a developer or partner in a landfill gas energy project is a complex issue. Each contract will be different depending on the specific nature of the project and the objectives and limitations of the participants. Because of this complexity, it is imperative that the landfill owner consult in-house counsel or hire a qualified attorney to serve as a guide through the contracting process.

Box 7.3 Elements of a Partnership Contract

The contract between the landfill owner and the developer or partner should describe in detail the responsibilities of each party, any payments to be made, and any warranties and/or guarantees. Some specific items that should be addressed include:

- Ownership shares;
- Allocation of development responsibility;
- Decisionmaking rights;
- Commitments of equity, financing, equipment, and/or services;
- Payments, fees, royalties;
- Hierarchy of project cash distributions;
- Allocation of tax credits;
- Allocation of specific risks (e.g., equipment performance, gas flow);
- Penalties, damages, bonuses;
- Schedule and milestones;
- Termination rights clause;
- Buy-out price; and
- Remedies/arbitration procedures.

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8. Winning/Negotiating An Energy Sales Contract

An energy sales contract will determine the success or failure of a project, since it secures the project's source of revenue. Therefore, successfully obtaining a contract is the crucial milestone in the project development process. This chapter provides a guide to the issues involved in bidding for, winning, and negotiating an energy sales contract. Because contract negotiation is often a complex process, owner/operators and developers may want to consult an expert for further information and guidance.

The Project Development Process

Part I
Preliminary Assessment of Project Options

- Determining if a Project is Right for Your Landfill
- Determining What Project Configuration is Right for Your Landfill

⇓

Part II
Detailed Assessment of Project Economics

- Evaluating Project Economics
- Assessing Financing Options
- Selecting a Project Development Partner
- Winning/Negotiating an Energy Sales Contract
- Securing Project Permits and Approvals
- Contracting for EPC and O&M Services

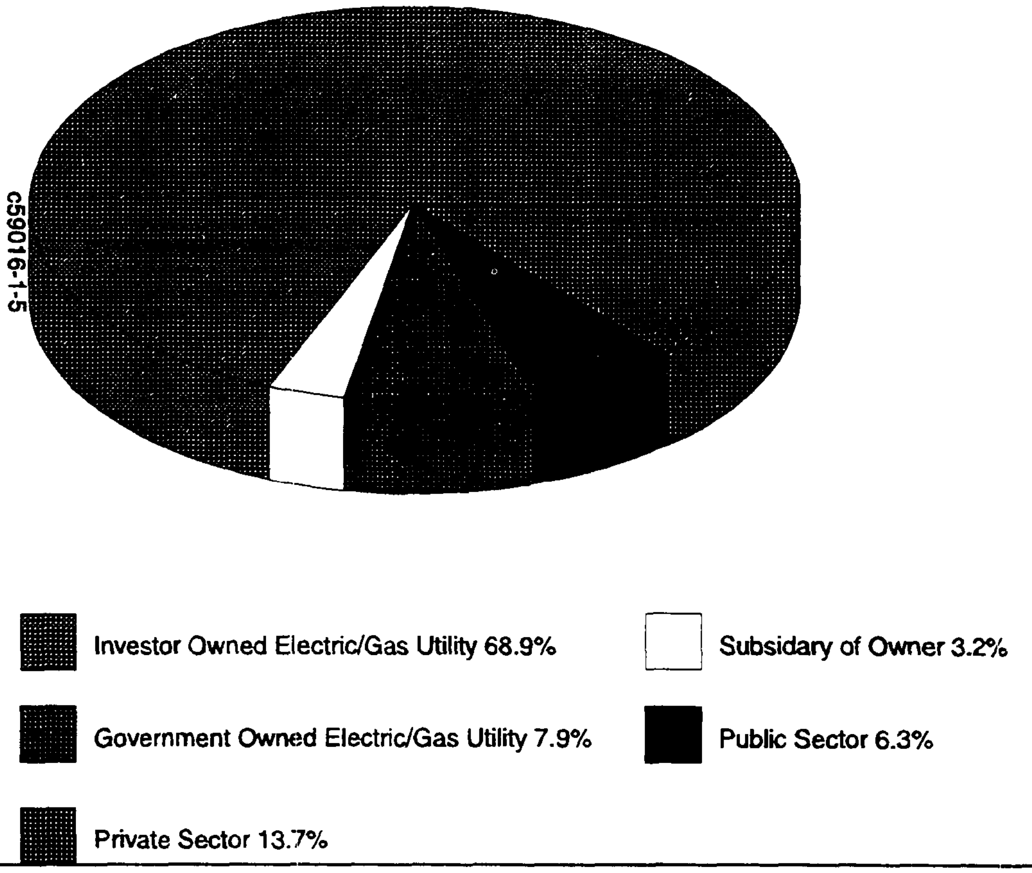
Depending on the configuration of the landfill gas-to-energy project, one of two types of energy sales contracts may be obtained:

Power sales contract – A long-term sales contract is necessary to ensure revenues for power projects, and is usually required to obtain financing. The power sales contract may be negotiated with an electric utility and/or a local end user. Additionally, if the sales contract is with a utility other than the one directly interconnected to the project, then arrangements with the local utility will be necessary to transport the power to the buyer. If the landfill gas-to-energy project will also sell steam or thermal energy, then the project must have a steam sales contract with the end user. Such contracts are directly negotiated between the project developer and the end user.

Gas sales contract – A gas sales contract is required when medium- or high-Btu gas sales are made. In cases where medium-Btu gas is sold as boiler (or other industrial equipment) fuel, a contract between the gas purchaser and the project developer is necessary. Such contracts are the result of direct negotiation. If high-Btu gas sales are made, the gas sales contract is typically between the local gas distribution company and the project developer, although a contract with a gas marketer is also possible.

The majority (about 69%) of existing landfill gas-to-energy projects have obtained power and gas sales contracts with investor-owned utilities. The remaining projects have contracts with private sector customers such as industrial facilities (14%), government-owned gas or electric utilities (8%), other public sector buyers, or subsidiaries of landfill gas plant owners [Berenyi and Gould, 1994]. These results are shown in Figure 8.1.

Figure 8-1 Types of Companies that Contracted with Landfill Gas Energy Recovery Projects for the Purchase of Gas or Electricity in 1994

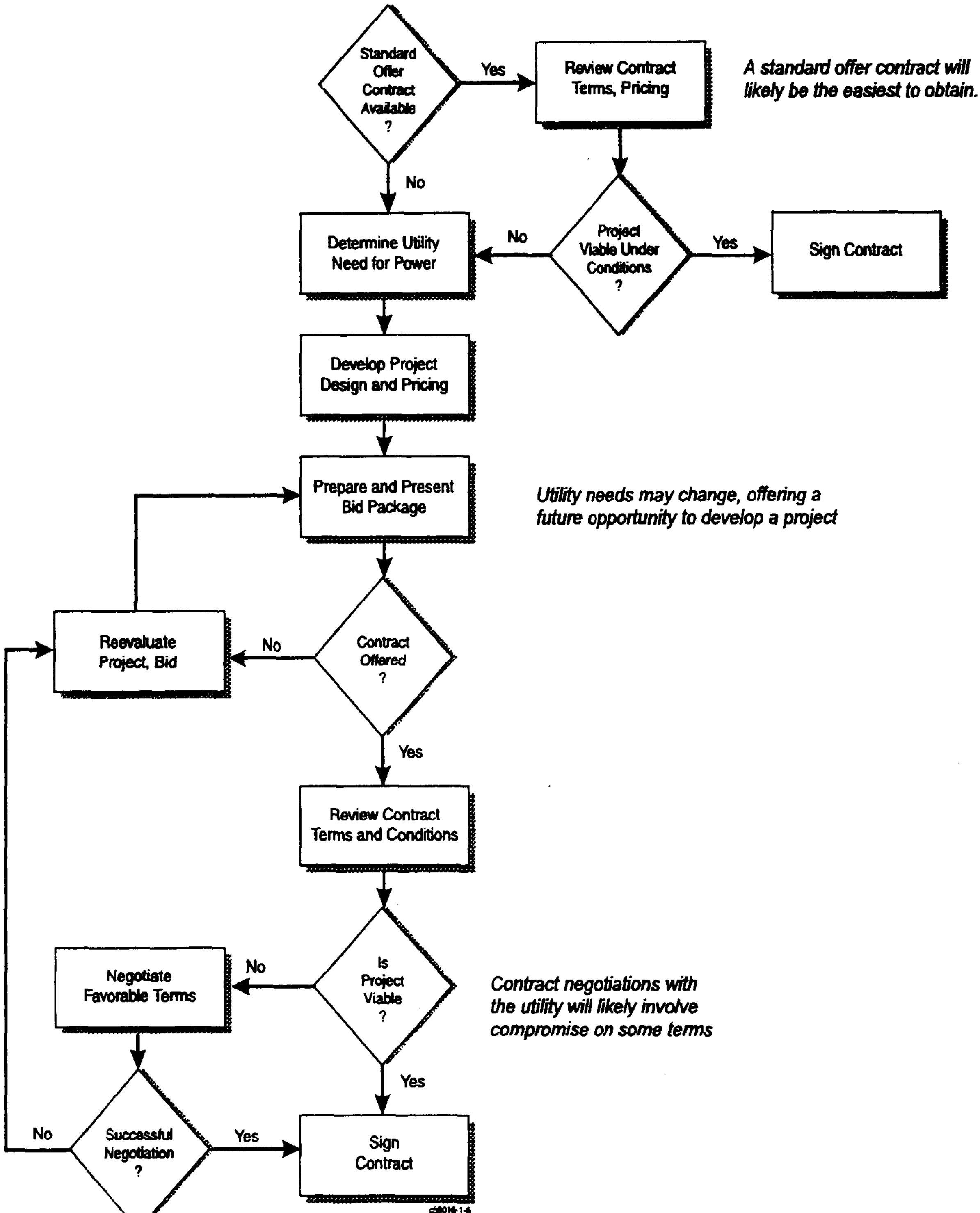


A landfill owner can either pursue a contract on its own or bring in an experienced project developer who will take the responsibility of obtaining a contract. This chapter provides insights on how landfill owners and project developers can win energy sales contracts with appropriate energy buyers, and contains a detailed outline of a power sales bid to an electric utility. Because the terms and conditions of the energy sales contract will determine the project's long-term viability, critical contract provisions are also briefly discussed.

8.1 Power Sales Contracts

There are two common types of power sales contracts: (1) standard offers and (2) power sales agreements either negotiated or won through a competitive bidding process. Figure 8.2 illustrates the steps involved in obtaining a power sales contract. As the figure indicates, standard offer contracts with local utilities are generally preferred when they are available at favorable terms. The majority of existing landfill gas power projects hold standard offer contracts with their local utilities because in the past they have been the easiest to obtain (however, standard offer contracts are disappearing and becoming more difficult to obtain). In cases where standard offers are either not available or not appropriate, however, power sales agreements may be sought. It is likely that the power sales agreement will be sought from the local utility. However, it may be possible to negotiate an agreement with a utility other than the one directly interconnected to the project, or to negotiate a contract with an end use consumer.

Figure 8-2 Winning/Negotiating An Energy Sales Contract (Power Sales Agreement)



Key issues related to power sales contracts are discussed below. Also discussed are the considerations to be taken into account when the power sales contract is negotiated with an entity other than the interconnected utility and wheeling arrangements are necessary.

8.1.1 Standard Offer Contracts

A standard offer contract is sometimes available from electric utilities that forecast a need for additional generating capacity. The standard offer contract specifies the terms and price that the utility will grant to eligible projects. Many standard offers require that projects be certified as "qualifying facilities" as defined by the Public Utilities Regulatory Policies Act (PURPA). Landfill gas projects are eligible to be qualifying facilities.

The standard offer price typically includes both a capacity payment and a variable energy payment. Standard offer contract prices are based on the utility's avoided costs; that is, the cost the utility would otherwise incur in providing electricity generating capacity and energy if it did not purchase this capacity and energy from the qualifying facility (QF). Most electric utilities are required to calculate their avoided cost and have it reviewed and approved by their state regulatory authority.

Many utilities go through cycles where capacity is needed, contracts are offered, contracts are signed, and then the standard offer is withdrawn until more capacity is needed. During the periods when additional generating capacity is not needed, utilities are likely to offer only a variable avoided short-term energy payment. Unfortunately, avoided energy payments are often too low to economically justify developing a project. For example, 1992 average U.S. utility avoided energy costs were in the 2.9 to 3.5¢/kWh range [ICF, 1994]. Even though a standard offer contract may not be available, project developers should still approach utilities to see if a contract can be negotiated.

How to Qualify for Standard Offers

In order to qualify for most standard offer contracts, a project must conform to the guidelines set by PURPA. Under PURPA, an electric utility is obligated to buy electricity from a power project at its current avoided cost rate if the project is granted QF status by the Federal Energy Regulatory Commission (FERC) as either a "small power producer" or a "qualifying cogenerator." PURPA prohibits utilities or utility holding companies from having more than 50 percent ownership in QF projects, and it stipulates size and fuel requirements as follows:

> Small power producer -- Small power producers must be no more than 80 MW in size and must use a primary energy source of biomass, waste, renewable resources, or geothermal resources. Most landfill projects would be considered small power producers.[1]
>
> Qualifying cogeneration facility – A cogeneration QF must produce useful thermal energy as well as electricity for sale to the utility. There is no size limitation; however, at least five percent of the cogeneration QF's total energy output must be provided to

[1] There are proposals within Congress to lift the 80 MW size limit. There is also some debate as to whether PURPA should be repealed completely.

a thermal energy user if a "topping cycle" is used.[2] An efficiency standard must also be met for facilities using natural gas or oil. For topping cycles, this efficiency standard will depend on the amount of useful thermal energy output provided [18 CFR, §292.205].

In addition to placing QF requirements into standard offer contracts, utilities also commonly require that size and operating conditions be met. For example, the contract may limit the amount of generating capacity (i.e., MW) for which the utility will pay. Applicants are also usually required to provide some type of reliability guarantee (e.g., posting a bond), backed up by penalties or reduced payments for nonperformance. It should be noted that reliability guarantee requirements vary from state to state. Note that some standard offer contracts may be available only to projects such as renewable energy or waste-to-energy projects that have special advantages. Such programs can create additional incentives to develop landfill gas projects.

Executing a Standard Offer

The electric utility's supply planning or power purchase department can provide details about available standard offer contracts and current avoided costs. This information can then be used in project economic calculations to determine if the project is viable. Standard offers usually provide variable short-term and fixed long-term payment options. The developer should choose the option that produces acceptable economics and enables the project to meet financing requirements. Appendix C contains the executive summary of a representative standard offer contract that was issued by one utility.

If the landfill owner/operator determines that the project is feasible under the set rates and contract conditions, the standard offer contract can be signed. In most cases, however, the state regulatory authority will review and approve the executed contract before it takes effect.

8.1.2 Bidding/Negotiating a Power Sales Agreement (PSA) With an Electric Utility

If a suitable standard offer is not available, a PSA may be pursued either through a utility bidding process or by presenting an unsolicited offer to the utility. This section discusses how to successfully negotiate a PSA by describing: (1) the request for proposals process; (2) what to include in an offer; (3) how utilities judge offers; and (4) contract considerations.

The Request for Proposal (RFP) Process

Utilities constantly review their energy needs and plan for the future, and this is usually done through the development of an integrated resource plan. If an energy need is identified,

[2] A "topping cycle" first uses energy input to produce power, then the rejected heat is used to provide useful thermal energy. In a "bottoming cycle", the sequence of energy use is reversed. There is no operating standard for a bottoming cycle QF.

a utility will sometimes solicit bids from power producers to fulfill that need by issuing an RFP.[3] Sometimes, an RFP will call for specific project types, such as renewables, although the majority of RFPs are all-source solicitations, meaning any technology bid is permitted.

A potential bidder must be aware of the specific type of electric capacity that a utility needs (i.e., baseload versus peaking capacity). Landfill gas projects are well-matched to utility baseload, or around-the-clock, needs, because landfill gas must be continuously recovered throughout the year to prevent migration and to efficiently operate the recovery equipment. In contrast, landfill gas projects are not compatible with peaking needs, or needs that occur only during the times of highest electric demand (typically 5 percent or less of the year). In a peaking project, most of the landfill gas would have to be flared, and the energy recovery project would be idle for the majority of the year.

Even when no RFP is outstanding, a project proponent can offer an unsolicited bid to the utility. In this situation, the project proponent would take the initiative to approach the utility (typically the supply planning or power purchase department) and present his or her project concept.

Bid Requirements

Bid requirements will determine the level of detail and the specific components to be included in a bid package. If an RFP is issued, the requirements are set by the utility, and its format must be followed. However, if an unsolicited bid is to be offered, there is some flexibility in format, although enough information should be included to allow the utility to make a judgement. A complete bid document is comprised of many components which describe and document the various aspects of a project. The most important aspects are pricing, equipment description, and contract terms. Standard bid components for RFP responses are outlined in Table 8.1.

Before compiling the separate components of a bid document, the bidder should identify the project's competitive advantages. A good way to do this is to first prepare a project summary that sets the tone for the whole bid. By keeping the project's competitive advantages in mind throughout the bid preparation process, each component can be integrated to enhance the entire bid. Examples of a landfill gas project's potential competitive advantages are listed in Box 8.1.

Bid Evaluation Process

Cost will likely be an overriding factor when the utility is judging a bid, and landfill gas projects may have to compete against a utility's self-build option or a conventional natural gas-fired project. Additional non-price factors that impact bid evaluation and may benefit landfill gas projects include: societal benefits, environmental benefits, location, project timing, reliability, and risks.

[3] Developers often study a utility's integrated resource plan (IRP) to anticipate upcoming capacity needs and solicitations. The electric utility and state regulatory authority can usually provide copies of the IRP.

Contract Considerations

The economic terms of a PSA are vital to a project; however, other contract terms and conditions affect the long-term viability and liability of the project as well. The entire contract offered by a utility should be carefully reviewed by the project developer and reliable legal counsel to ensure that each of the terms is acceptable. If they are not, a more acceptable, revised version of the contract should be presented to the utility for negotiation.

Primary contract considerations include:

Term – The contract term should be sufficient to support financing and/or the life of the project. A satisfactory term is usually 15 years or more [Knapp, 1990].

Termination – Grounds for contract termination should be very limited in order to protect the long-term interests of all parties.

Assignment – The contract should contemplate assignment for purposes such as financing. For example, allowing for contract assignment to a subsidiary or to partners may be advisable to avoid ownership arrangement difficulties [Knapp, 1990].

Force majeure[4] – Situations that constitute force majeure (e.g., storms, acts of war) should be agreed upon, otherwise this clause could be used to interrupt operations or payment.

Schedule – There should be some flexibility allowed for meeting milestone dates and extensions (e.g., in penalty provisions). This is necessary in case unforeseen circumstances cause delays.

Price – The contract price should ensure the long-term viability of the project, which means that accounting for potential cost escalation through the contract will be very important. An example price structure that can be negotiated to accomplish this is multi-part pricing, described in Box 8.2.

[4] A *force majeure* clause provides for situations that occur when circumstances beyond the control of either party disrupt normal operations. Penalties may be waived or reduced during force majeure events. Examples of force majeure events are earthquakes, hurricanes, strikes, riots, and acts of war.

Box 8.1 Multi-Part Pricing

A multi-part pricing scheme is one way to ensure long-term project viability by matching revenues with project expenses. The objective of this price structure is to ensure coverage of fixed costs (e.g., debt payment, fixed O&M), regardless of how often the project is called upon to run. The utility's decision to run the project is based on how the project's energy costs compare to those of other generating sources (in the case of landfill gas projects, these costs are very low, thus encouraging high levels of operation). A multi-part price contains two or more of the following components:

Capacity payment ($/kW) – This fixed payment is based on the capital costs of the project. The payment should be high enough to ensure that the project can meet its debt service and equity return requirements, regardless of how often the utility chooses to run the project.

Energy payment ($/kWh) – A variable energy payment is usually tied to fuel costs, which are very low for landfill gas projects.

Operation & Maintenance ($/kWh and/or $/kW) – This is a variable and/or fixed payment, which covers O&M costs of the project.

Start-up payment ($) – A fixed price is sometimes paid to the project each time it is called upon to run. It covers the costs of start-up (e.g., electric demand costs, equipment wear).

8.1.3 Bidding/Negotiating a PSA with an End User

Some state regulatory authorities will allow non-utility power projects to make electricity sales directly to end users. However, such sales, when permitted, are typically limited to a number of contiguous neighbors.[5] In the near future, unconditional sales to retail end users may be permitted as a result of deregulation in the electric industry. When end user sales are sought, it is up to the landfill gas power project to negotiate contract terms and conditions with the customer.

When negotiating an end user PSA, it will likely be necessary to offer the customer an electricity rate that provides a discount over the rate currently paid to the local utility (i.e., a rate based on the customer's avoided cost). Since retail electric rates are typically higher than the buyback rates available from utilities, this type of displacement arrangement can be very attractive to both the buyer and seller. For example, in 1992, the average posted U.S. retail electric rate to industrial customers was ¢4.8/kWh; commercial rates averaged ¢7.6/kWh for the same period [Energy Information Administration, 1994]. In comparison, average 1992 utility avoided cost buyback rates ranged from ¢2.9/kWh to ¢3.5/kWh [ICF, 1994].

[5] Because state regulatory policies vary, it is essential that landfill owners/operators contact authorities to determine any limitations or conditions governing direct electricity sales to end users before trying to negotiate a PSA.

Table 8-1 Typical Bid Components

BID COMPONENT	DOCUMENTATION CHECKLIST
Siting	• map, showing site location (e.g., USGS map) • site plan • purchase option agreement (if necessary) • description of rights-of-way (if applicable) • environmental assessment
Electric Interconnect	• load flow study (if required) • location of point of interconnection
Technology	• project design configuration • equipment specifications • technology status, experience • vendor guarantees (performance, timing, cost)
Fuel Supply	• reports on viability of field (reliability is key) • cost, fuel price escalation • documentation of long-term supply (historical data) • documentation of gas rights
Experience	• description of developer experience
Timing	• timeline for permitting, construction • commercial operation date
Permitting	• zoning plan • air plan • water plan
Financing	• plan • debt coverage ratios • pro forma
Pricing	• breakdown of project cost • capacity • energy • indices (e.g. fuel price escalation)
Regulatory Status	• FERC QF filing • agreement with steam host (if applicable)
Operation & Maintenance	• maintenance schedule • flexibility
Contract Terms	• marked-up contract terms (see section on contract considerations)

Box 8.2 Potential Competitive Advantages of Landfill Gas Projects

- Landfill gas comes from one local source, and it usually costs less than conventional fuels.
- Landfill gas energy recovery is a proven technology. Operators and equipment manufacturers have gained experience with the conversion technologies used in landfill gas recovery operations.
- Landfill gas recovery projects provide a net environmental benefit by reducing methane and volatile organic compounds emissions, conserving fossil fuels, reducing explosive hazards, and reducing odor. In addition these benefits ease the permitting process, may be shared with the utility, or used as a bargaining chip.
- Most landfill gas projects are situated at a landfill site, which may ease or eliminate local permitting and zoning requirements.
- The price of fuel and equipment is fixed at the project outset; there is only minimal price escalation.
- Landfill gas projects can serve on-site electrical loads at dispersed locations, thus reducing the need for new generating plants and transmission facilities.
- Landfill gas projects offer a way for utilities to attain Climate Challenge voluntary greenhouse gas emission reduction targets.
- Title IV of the Clean Air Act (Acid Rain Program) creates a quantifiable value for avoided SO_2 emissions. Each ton of SO_2 avoided through generation of electricity from landfill methane saves one emission allowance for utilities affected by Title IV. For those utilities not affected until the year 2000, each 500 MWh of electricity produced by landfill gas may be worth one "bonus" allowance (currently at $150 each). See Appendix I.

The basic contract terms and conditions to be considered when negotiating a PSA with an end user will be the same as those outlined above for a utility PSA: term, termination, assignment, force majeure, schedule, and price. Also, it is usually desirable to use a multi-part price structure (see Box 8.2), even with non-utility customers. The concept should not be foreign to industrial and commercial facilities, because electricity and gas are commonly purchased under a tariff that includes an energy component, demand component, and customer charge.

8.1.4 Wheeling Arrangements

A power project may be unable to obtain a favorable power sales contract with the utility to which it is directly interconnected. In such instances it may be possible for the project to transport, or "wheel," its power over the local utility's transmission system in order to sell to a third party. When wheeling is necessary to reach a buyer, arrangements must be made with the local utility to specify the terms and conditions for the wheeling service.

The three basic types of wheeling services are: (1) wholesale; (2) self-service; and, (3) retail. As a result of recent regulation, all utilities will soon be required to provide wholesale wheeling to power producers at specified rates. However, self-service wheeling is currently only permitted in three states (Connecticut, Florida, and Maine) and retail wheeling is currently only allowed in very limited circumstances in Nevada.

Wholesale Wheeling

Wholesale wheeling occurs when a utility transports power over its transmission system for delivery to another utility. All utilities may soon be required by FERC to provide wholesale wheeling services to power projects; however, there is currently much debate about how to determine the rates charged for these services. It is important to keep in mind that the transmission rates will determine if it is economical to make off-system sales. For example, if it costs ¢4.7/kWh to produce electricity and ¢2/kWh to transport it to the buyer, then the total delivered electricity cost of ¢6.7/kWh may not be low enough to justify the sales transaction.

Self-Service Wheeling

If a landfill gas owner/operator wants to deliver power to another of its facilities located elsewhere on the local utility's system, then it may be possible to have the utility transport the project's output to the site on behalf of the landfill owner/operator. For example, if a county that owns the local landfill, the county prison facility, and various other office buildings located around town then develops a power project at the landfill site, it could arrange to have the local utility transport (i.e., wheel) the electricity from the project to the prison and courthouse. This type of transmission service is known as self-service wheeling.

Currently, only three states--Connecticut, Florida, and Maine--permit self-service wheeling. However, self-service wheeling has never been tried in some states, so if it is beneficial to a project, then the landfill owner/operator should contact state regulatory authorities to determine if it would be permitted.

Retail Wheeling

In the future, there may be expanded opportunities for power projects to make sales directly to retail end users such as industrial facilities, hotels, and commercial buildings. Currently, "retail wheeling", which means the sale of electricity directly to a retail customer using the local electric utility's transmission lines, is prohibited in most states. The concept of retail wheeling includes transmission service, which sets it apart from on-site electric sales from a power project to an adjacent facility. Retail wheeling is currently allowed in Nevada under limited circumstances, Michigan will soon begin a retail wheeling experiment, and California has proposed regulations which would permit retail wheeling for some customers beginning in 1996. Several other states are also considering the issue. On-site electric sales to adjacent facilities are allowed under certain circumstances in several states. In addition, some utilities are beginning to launch pilot programs under which retail wheeling is allowed. The possibility of direct sales to distant or adjacent facilities represents an important future opportunity, since the revenues from retail electricity buyers would most likely be higher than is available from wholesale (i.e., utility) buyers.

8.2 GAS SALES CONTRACT (MEDIUM OR HIGH-BTU)

Gas sales contracts are a product of successful negotiation between the landfill gas project developer and the gas user or distributor. When negotiating a contract, it is important to keep in mind the project's requirements (i.e., revenue, operational considerations), while at the same time knowing where compromises can be made to accommodate the customer's needs.

Figure 8.3 outlines the steps involved in winning a gas sales contract. As illustrated, customer needs and contract considerations will vary, depending on whether the gas product to be sold is medium-Btu or high-Btu gas. Medium-Btu sales contracts are obtained with direct use customers, such as industrial companies or commercial complexes, whereas high-Btu contracts are typically negotiated with local gas distribution companies. Customer proximity is a primary factor in determining the feasibility of either type of project.

8.2.1 Medium-Btu Gas Sales

Medium-Btu sales contracts are usually unsolicited and initiated by the developer. Negotiations for a contract should begin with a potential gas customer (as represented by a plant manager or plant engineer) during initial feasibility studies. It is important that the developer obtain an initial indication of the price and terms that the gas customer is willing to accept, so that they can be taken into consideration during later contract negotiations. Usually these are dependent on the price and delivery terms of the existing or alternate fuel supply.

Specific contract items which document each party's responsibility and limit landfill liability and risk exposure are:

Gas price – This $/MMBtu price could include fixed and variable components.

Equipment retrofit/modifications – It should be clear who is responsible for the capital cost of any required changes to the gas purchaser's equipment; this will avoid any confusion or misunderstanding between parties.

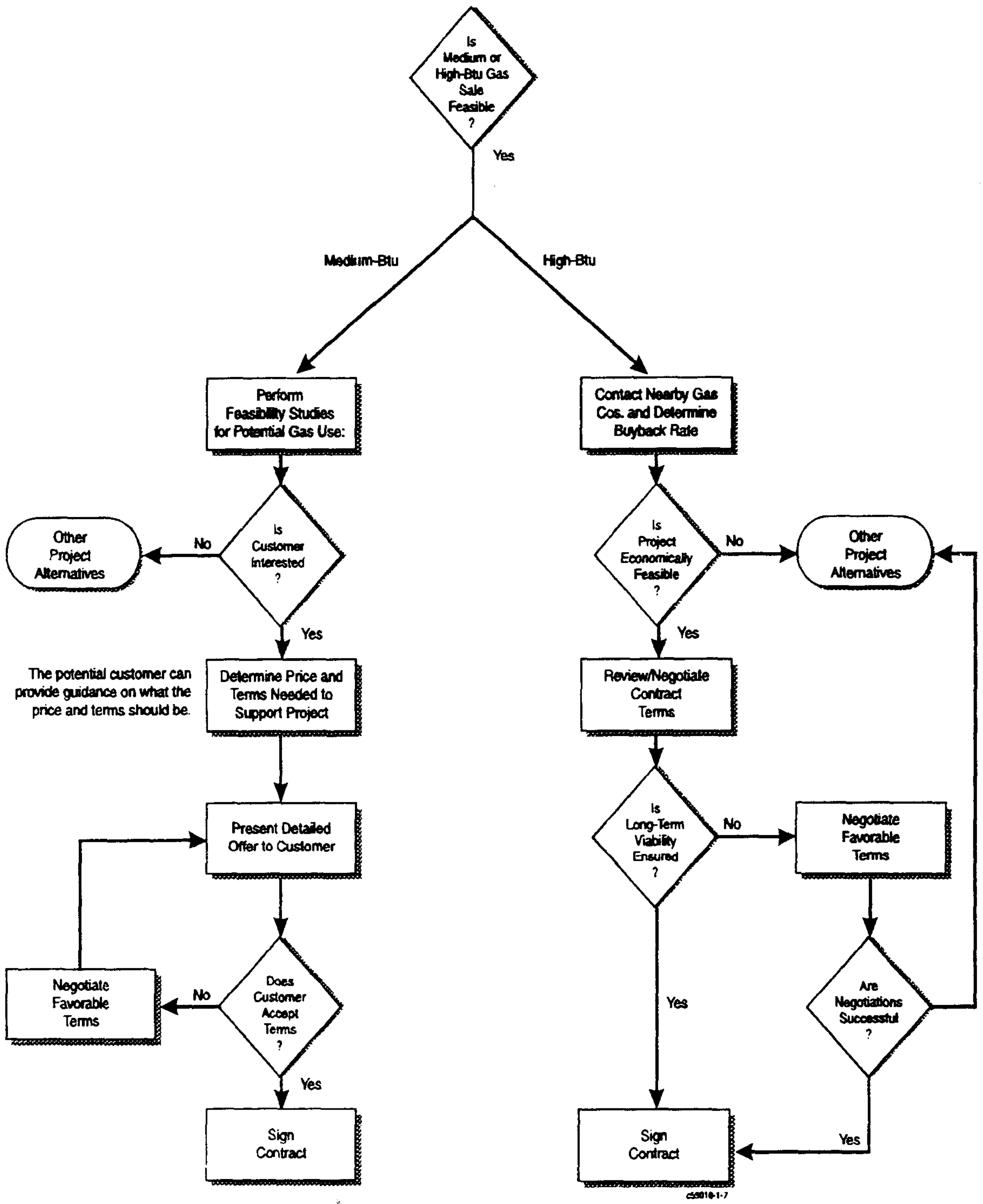
Pipeline construction and maintenance – Frequently, a dedicated pipeline will be required to transport the landfill gas from the site to the customer. Responsibility for pipeline construction costs and O&M should be clearly defined, which will help ensure that the pipeline is completed on time and is properly maintained.

Minimum purchase amounts – The amount (daily, annual, or total) of gas that the customer is required to buy, and that the landfill is required to provide, should be set, with some tolerances allowed. This will help to define the size of the project and will ensure revenues.

Changes in purchase amounts – The situation in which either party wishes to increase/decrease purchase amounts should be addressed, with flexibility allowed (e.g., decrease in landfill gas production or plant needs).

Alternate fuel – If a backup, or secondary, fuel is required to operate the gas purchaser's equipment, then the contract should clearly define who is

Figure 8-3 Winning/Negotiating An Energy Sales Contract (Gas Sales)



responsible for purchasing the fuel under a variety of circumstances (e.g., landfill is responsible if production falls due to well maintenance problems).

8.2.2 High-Btu Gas Sales

Local distribution companies (LDCs) require a reliable supply of natural gas to serve their customers, and they have a variety of supply contracts in place to meet these needs. Some are long-term, while others only last for periods of one month or less. Contracts that provide price stability and supply reliability are attractive. Landfill gas can provide both, and may therefore have an advantage over conventional natural gas supplies if the energy recovery project is economic.

Some LDCs occasionally request proposals for gas supply packages; however, it is unlikely that an RFP process will be used to obtain a high-Btu sales contract. The best way to obtain a contract is to first contact the LDC's gas supply department to determine pricing options. If the project is economically viable given the LDCs projected buyback rates, further consideration should be given to specific contract terms.

Things to consider in negotiating a contract with an LDC include:

<u>Take-or-pay clauses</u> – It will be advantageous to the project if the utility is required to pay for a set amount of gas even if it does not take delivery; however, the LDC will likely resist such a clause.

<u>Interconnect costs</u> – The responsibility for the cost of construction and maintenance of interconnect facilities (e.g., pipelines, connections, metering, pressure regulation, filtering, moisture removal) should be clearly delineated. Pass-through to the gas seller of taxes assessed on construction costs are an especially important issue with interconnects, since project configuration may determine their applicability.

<u>Gas pressure and quality requirements</u> – These must be defined at the outset, as they will determine the amount of gas processing needed. This is important for landfill gas projects because gas compression and enrichment are expensive.

<u>Standby or non-performance clauses</u> – These should be defined at the outset as they will determine any fines or penalties that are incurred as a result of non-compliance with the contract.

<u>Terms and times of delivery</u> – The amount (daily, annual, or total) and times of delivery of gas that the customer is required to buy, and that the landfill is required to provide, should be set, with some tolerances allowed.

9. Securing Project Permits and Approvals

The Project Development Process

Part I
Preliminary Assessment of Project Options

- Determining if a Project is Right for Your Landfill
- Determining What Project Configuration is Right for Your Landfill

⇓

Part II
Detailed Assessment of Project Economics

- Evaluating Project Economics
- Assessing Financing Options
- Selecting a Project Development Partner
- Winning/Negotiating an Energy Sales Contract
- Securing Project Permits and Approvals
- Contracting for EPC and O&M Services

Obtaining required environmental, siting, and other permits is an essential step in the development process. Permit conditions often affect project design, and neither construction nor operation can begin until all permits are in place. The process of permitting a landfill gas-to-energy project may take anywhere from six to eighteen months (or longer) to complete, depending on the project's location and recovery technology. For example, a project sited in a location that requires no zoning variances and that meets national air quality standards will probably take much less time to permit than a project subject to zoning hearings and stringent air quality requirements.

Landfill gas energy recovery projects must comply with federal regulations related to both the control of landfill gas emissions and the control of air emissions from the energy conversion equipment. Regulations promulgated under two separate federal acts specifically address emissions from municipal solid waste landfills:

- Resource Conservation and Recovery Act (RCRA) regulations focus on landfill gas hazard and nuisance abatement [40 CFR, §258.23].

- Clean Air Act regulations focus on control of landfill gas emissions [61 FR 9905, March 12, 1996].

Air emissions from energy recovery projects are addressed in other sections of the Clean Air Act. This chapter briefly discusses these major federal regulations and their impacts on landfill gas energy recovery projects. It should be noted that states are generally granted the authority to implement, monitor, and enforce the federal regulations by establishing their own permit programs. As a result, some state permit program requirements are more stringent than those outlined in the federal regulations and there is a large state-to-state variance in agencies and standards. For this reason, landfill owner/operators and project developers should determine state and local requirements before seeking project permits.

9.1 THE PERMITTING PROCESS

There are four general steps (outlined in the flowchart in Figure 9.1) that will help ensure that the necessary permitting requirements under applicable state and federal regulations are met:

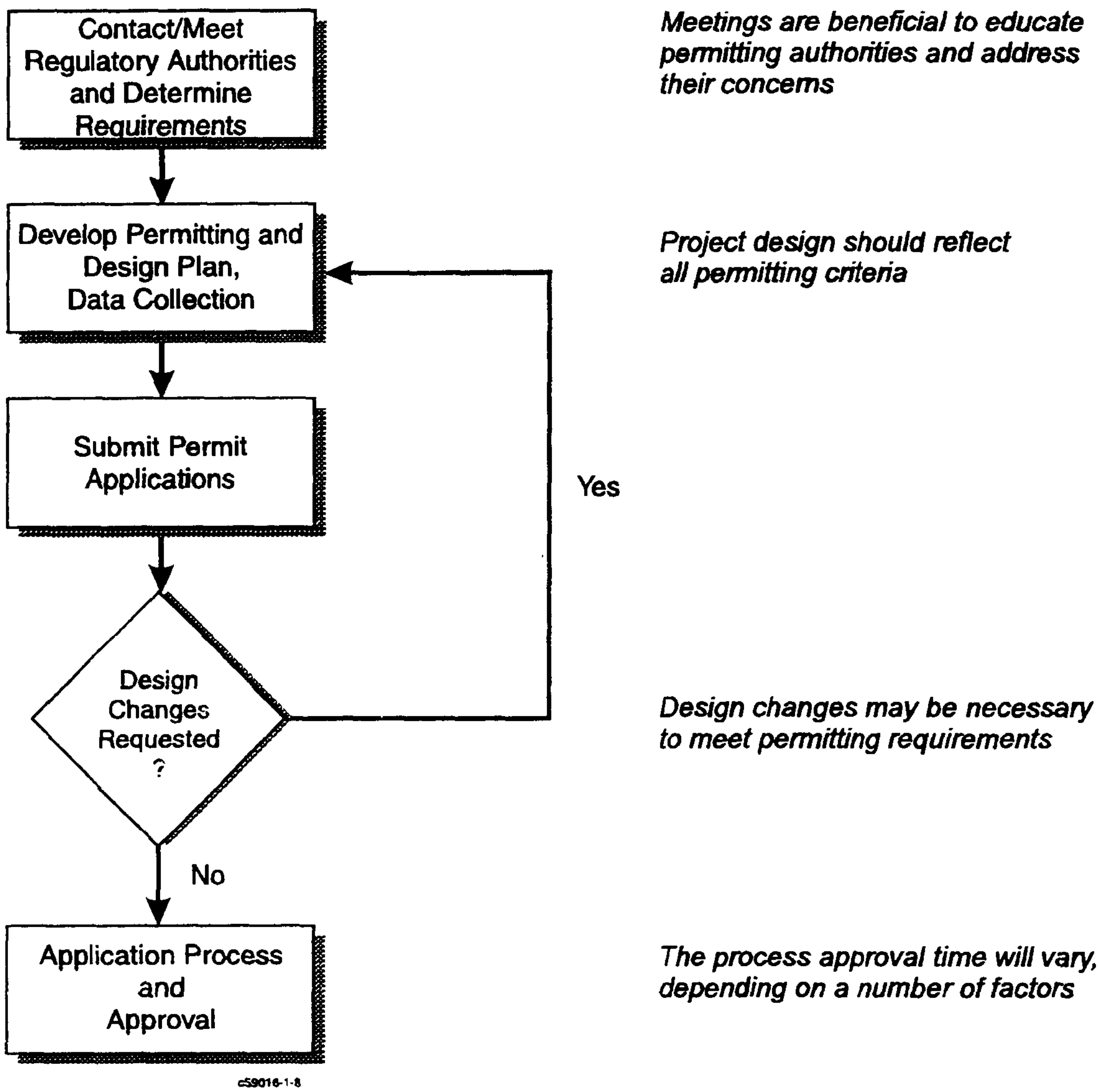
> Step 1. Hold preliminary meetings with key regulatory agencies. Discuss with regulators the requirements and issues they feel must be addressed. These meetings also give the developer the opportunity to educate regulators about the project, since, in many cases, landfill gas-to-energy technologies may be unfamiliar to regulators.
>
> Step 2. Develop the permitting and design plan. Determine the requirements and assess agency concerns early on, so permit applications can be designed to address those concerns and delays will be minimized.
>
> Step 3. Submit timely permit applications to regulators. Submit complete applications as early as possible to minimize delays.
>
> Step 4. Negotiate design changes with regulators in order to meet requirements. Permitting processes sometimes provide opportunities for project sponsors to negotiate the appropriate control measure and level with regulators. If negotiation is allowed, it may take into account technical as well as economic considerations.

As these steps indicate, the success of the permitting process relies upon a coordinated effort between the developer of the project and various local, state, and federal agencies who must review project plans and analyze their impacts. For landfill gas projects in particular, developers often must deal with separate agencies with overlapping jurisdictions over landfill operations and energy recovery operations (e.g., solid waste and air quality authorities). This underscores the importance of coordinating efforts to minimize difficulties and delays.

In some cases, permitting authorities may be unfamiliar with the characteristics and unique properties of landfill gas. Where appropriate, the landfill owner/operator or project developer should approach the permitting process as an opportunity to educate the permitting authorities, and should provide useful, targeted information very early in the process.

Emphasizing the pollution control aspects of landfill gas energy recovery projects can be an effective approach in seeking permits. If a landfill gas collection and flare system has not yet been installed or does not collect the full quantity of landfill gas emitted, then there is a substantial opportunity to reduce non-methane organic compounds (NMOC) and methane emissions from the landfill. An energy recovery project can further reduce these emissions by capturing additional landfill gas, as well as reducing emissions of carbon dioxide, sulfur dioxide, and other pollutants by displacing a fossil fuel source. Approaching and presenting the project as a pollution control project that will cause a net reduction in emissions can make the air permitting process much easier.

Figure 9-1 Project Permitting



9.2 RCRA SUBTITLE D

RCRA Subtitle D, established to ensure the protection of human health and the environment, sets minimum national design, operating and closure criteria for municipal solid waste landfills that were active on or after October 9, 1993. Virtually all currently operating municipal solid waste landfills are considered affected landfills under RCRA. Landfill gas control is one item addressed in the regulations.[1]

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[1] RCRA Subtitle D applies to affected landfills, regardless of whether an energy recovery project is in place.

Landfill gas control is achieved by requiring affected landfills to establish a program to periodically check for methane emissions and prevent offsite migration. Landfill owners or operators must ensure that the concentration of methane gas does not exceed: (1) 25 percent of the lower explosive limit for methane in facility structures (excluding gas control or recovery system components); and, (2) the lower explosive limit for methane at the facility boundary. Permitted limits on methane levels reflect the fact that methane is explosive within the range of 5 to 15 percent concentration in air. If methane emissions exceed permit limits, corrective action (i.e., installation of a landfill gas collection system) must be taken [40 CFR, §258.23]. Subtitle D may provide an impetus for some landfills to install energy recovery projects in cases where a gas collection system is required for compliance.

Subtitle D requirements for methane emissions monitoring affect landfills not only during operation, but also for a period of thirty years after closure.

9.3 CLEAN AIR ACT

The Clean Air Act (CAA) addresses landfill gas-to-energy recovery project emissions in two ways:

(1) Regulation to control the emissions of non-methane organic compounds found in landfill gas, and

(2) Regulation of airborne emissions from the combustion sources used in landfill gas energy recovery.

This section explains how the CAA regulations apply to and impact landfill gas energy recovery projects.

9.3.1 Landfill Gas Emissions

On March 12, 1996, EPA promulgated New Source Performance Standards (NSPS) and Emissions Guidelines (EG) for landfills under the authority of Title I of the Clean Air Act (61 FR 49, 9905, March 12, 1996). The regulations target landfill gas emissions because they contain non-methane organic compounds (NMOCs), which contribute to smog formation. The requirements of the NSPS and EG are basically the same, with the main difference being the timing of implementation and the lead agency--the EPA administers the NSPS which takes effect immediately, while the states implement the EG once they have completed and received EPA approval of their implementation plans.

The regulations require landfill gas control at municipal solid waste landfills that meet all of the following criteria:

<u>Age</u> - The NSPS apply to all "new" landfills--i.e., those that began construction, reconstruction, or accepting wastes for the first time on or after May 30, 1991 (the date the proposed regulations were published in the Federal Register). The EG apply to "existing" landfills--i.e., those that accepted wastes on or after November 8, 1987. Both "new" and "existing" landfills are referred to below as "affected" landfills." Landfills that were closed prior to that date are not subject to the regulations.

Capacity – Affected landfills with a design capacity greater than 2,500,000 Mg (2,750,000 tons) are subject to the emission rate criterion described below.

Emission rate – Affected landfills meeting the capacity criterion must collect and combust their landfill gas if their maximum annual NMOC emission rate is greater than 50 metric tons. This emission rate can be determined either by desktop calculation using an EPA model (known as a Tier One analysis), or by EPA-defined physical testing procedures (known as Tier Two or Tier Three determinations).

Affected landfills that must collect and combust their landfill gas can use a flare system or an energy recovery system that has been demonstrated to reduce NMOC emissions by 98 percent. Landfill gas-to-energy should be evaluated at each landfill site to determine whether it is cost-effective, as it offers landfill owners an opportunity to mitigate the costs of compliance with the regulations. In addition to control requirements, the proposed regulations also contain recordkeeping and reporting requirements.

As the permitting process outlined in Figure 9.1 indicates, it will be important to contact regulatory authorities in order to determine and verify applicability criteria before developing a compliance plan. Appendix B is a list of regional and federal EPA offices that can provide detailed information about the regulations.

9.3.2 Regulations Governing Air Emissions from Energy Recovery Systems

Regulations have been promulgated under the CAA governing airborne emissions from new and existing sources. These regulations require new stationary sources and modifications to existing sources of certain air emissions to undergo the New Source Review (NSR) permitting process before they can operate.[2] The purpose of these regulations is to ensure that sources meet the applicable air quality standards for the area in which they are located. The applicable air quality standards are determined, in part, by the National Ambient Air Quality Standards (NAAQS), which have been set by EPA for six criteria air pollutants.

Two aspects of the NAAQS affect the stringency of the NSR permitting process. First, it sets overall regional ambient air loadings for the criteria pollutants. Using these levels, most areas of the country are classified as in "attainment" or "nonattainment" for each criteria pollutant. Areas that meet the NAAQS for a particular air pollutant are classified as in "attainment" for that pollutant, while areas that do not meet the NAAQS for a particular air pollutant are classified as in "nonattainment" for that pollutant. The same area may be in attainment for one air pollutant, but in nonattainment for another pollutant. Nonattainment areas are further categorized by their degree of nonattainment: marginal, moderate, serious, severe, and extreme. The greater the degree of nonattainment, the more stringent the regulations are in bringing that area to attainment and the lower the acceptable emission levels of particular pollutants will be. Some areas of the country are "unclassified" for all or some pollutants. An area that is listed as "unclassified" for a particular pollutant is one that has not had a project undergo the air permitting process for that pollutant.

[2]The EPA's NSR regulations for nonattainment areas are set forth in 40 CFR 51.165, 52.24 and part 51, Appendix S. The PSD program is set forth in 40 CFR 52.21 and 51.166.

Second, the NAAQS sets emission levels for new stationary sources and for modifications to existing sources. These levels are expressed in terms of total atmospheric loadings (i.e. tons emitted per year), as opposed to emission rates (tons/kwh), and are dependent upon location (attainment or nonattainment area) and the type of source (new or existing and its quantity of emissions). New sources or modifications to existing sources that exceed these NAAQS emission levels are classified as "major" sources while those that do not are classified as "minor" sources.

The principal air permitting requirements for landfill projects in attainment and nonattainment areas are described in detail below. As the discussion indicates, new stationary sources and modifications to existing sources in attainment areas undergo Prevention of Significant Deterioration (PSD) permitting while those in nonattainment areas undergo Nonattainment Area permitting. The basic difference between these processes is that the NSR permitting requirements are more stringent for major sources or modifications in nonattainment areas than for those same sources or modifications in attainment areas.

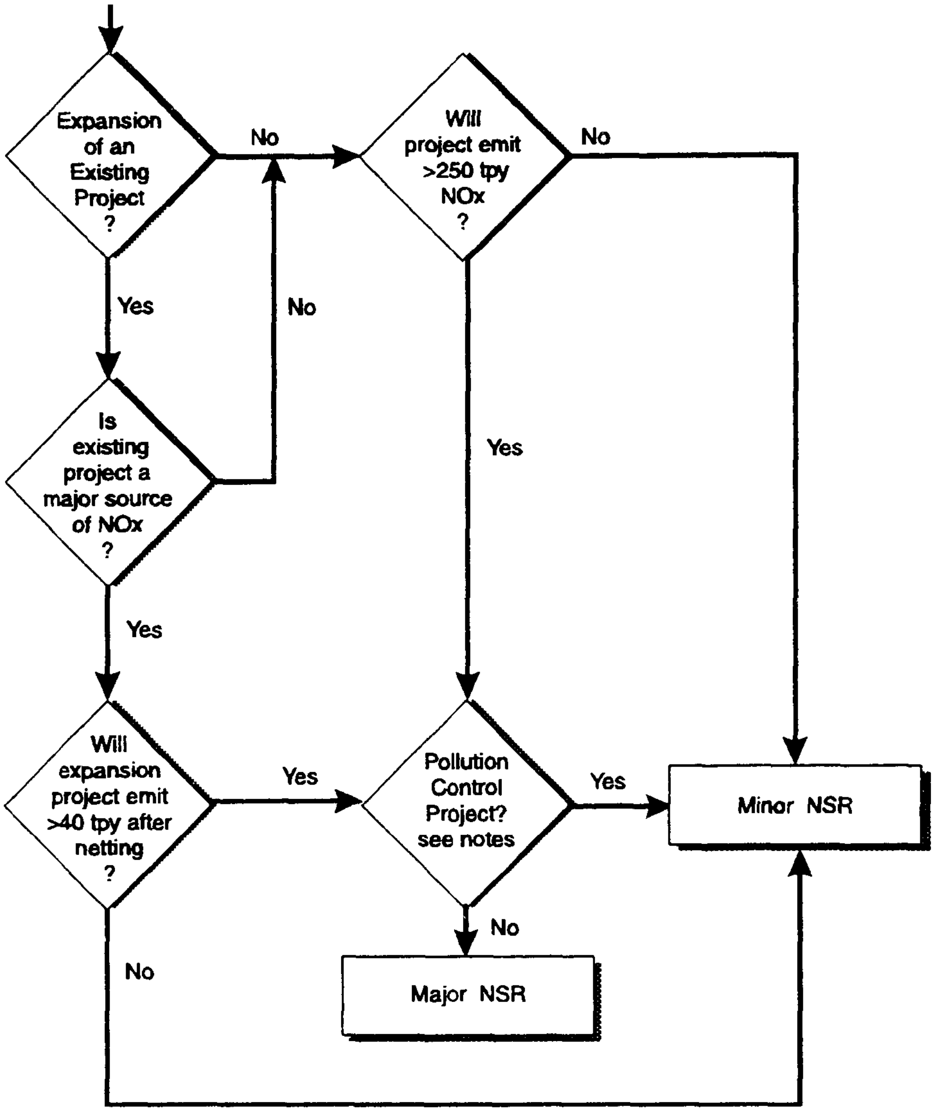
Most landfill energy recovery projects will likely be affected by the NAAQS standards for nitrogen oxides (NOx) and carbon monoxide (CO). Whether a major NSR is required at a particular landfill project will depend on the level of emissions resulting from the project (which is primarily a function of project size and technology) and the project's location (attainment or one of the five degrees of nonattainment). As discussed below, small projects and/or those located in attainment areas may find the air permitting process to be quite straightforward (minor NSR), while larger projects, particularly those in nonattainment areas, may require major NSR, which is more extensive. In any event, given the complexity of the air permitting regulations, a landfill owner or operator may wish to consult a local attorney or other expert familiar with NSR permitting requirements in a particular area.

Attainment Area Permitting or PSD Permitting

PSD review is used in attainment areas to determine whether or not a new or modified emissions source will cause significant deterioration of local air quality. All areas are governed to some extent by PSD regulations because it is unlikely that a given location will be in nonattainment for all criteria pollutants. Applicants must determine PSD applicability for each individual pollutant. For gas-fired sources, including landfill gas energy recovery projects, PSD and major NSR is required if the new source will emit or has the potential to emit any criteria pollutant at a level greater than 250 tons per year. A modification to an existing emission source is considered major if one of the following conditions is met: (1) the existing source is already a major source of a particular air pollutant and the modification will emit that air pollutant at a level greater than the PSD significance level or, (2) if the existing source is minor for a particular air pollutant and the modification will emit that air pollutant at a level greater than the major new source threshold. Figure 9.2 shows a simplified flow diagram of determining whether a new source or modification is major in an attainment area.

For each pollutant for which the source is considered major, the PSD major NSR permitting process requires that the applicants determine the maximum degree of reduction achievable through the application of available control technologies. Specifically, major sources may have to undergo any or all of the following four PSD steps: (1) Best Available Control Technology (BACT) analysis, (2) monitoring of local air quality, (3) source impact analysis/modeling (i.e. impact on local air quality), and (4) additional impact analysis/modeling (i.e. impact on vegetation, visibility, and Class I areas). The key component of the PSD process is the BACT analysis, which requires that the most stringent

Figure 9-2 Applicability of New Source Review Requirements in Attainment Areas for Ozone: Emissions of NOx Used as an Example



Notes:

A Pollution Control Project must be both:

(a) environmentally beneficial; and
(b) not cause or contribute to a violation of a NAAQS or PSD increment, or adversely affect an AQRV in a Class I area.

In addition:

- The permitting authority must determine that the project qualifies as a pollution control project.
- The permitting authority must provide an opportunity for public review and comment on the project's application and the proposed NSR exclusion.

control technology available must be used in a facility, unless the applicant can demonstrate that it is not feasible due to energy, environmental, or economic reasons.

Minor sources and modifications are exempt from this rigorous process, but these sources must still obtain construction and operating air permits. Minor sources must demonstrate, through calculations, modeling, vendor guarantees, or other analysis, that the source's emissions will not exceed applicable PSD levels. Many states require even minor sources to complete a BACT analysis and use BACT, although minor sources are usually not required to gather local air quality data or model impacts. New sources or modifications are considered major for NOx or CO if they exceed the limits shown in Table 9.1.

Table 9-1 Attainment Area Limits for NOx and CO

Pollutant	**New Sources** are Considered Major if Emissions Exceed (in TPY)	**Modifications to an Existing Minor Source** are Considered Major if Emissions Exceed (in TPY)	**Modifications to an Existing Major Source** are Considered Major if Emissions Exceed (in TPY)
NOx	250	250	40
CO	250	250	100

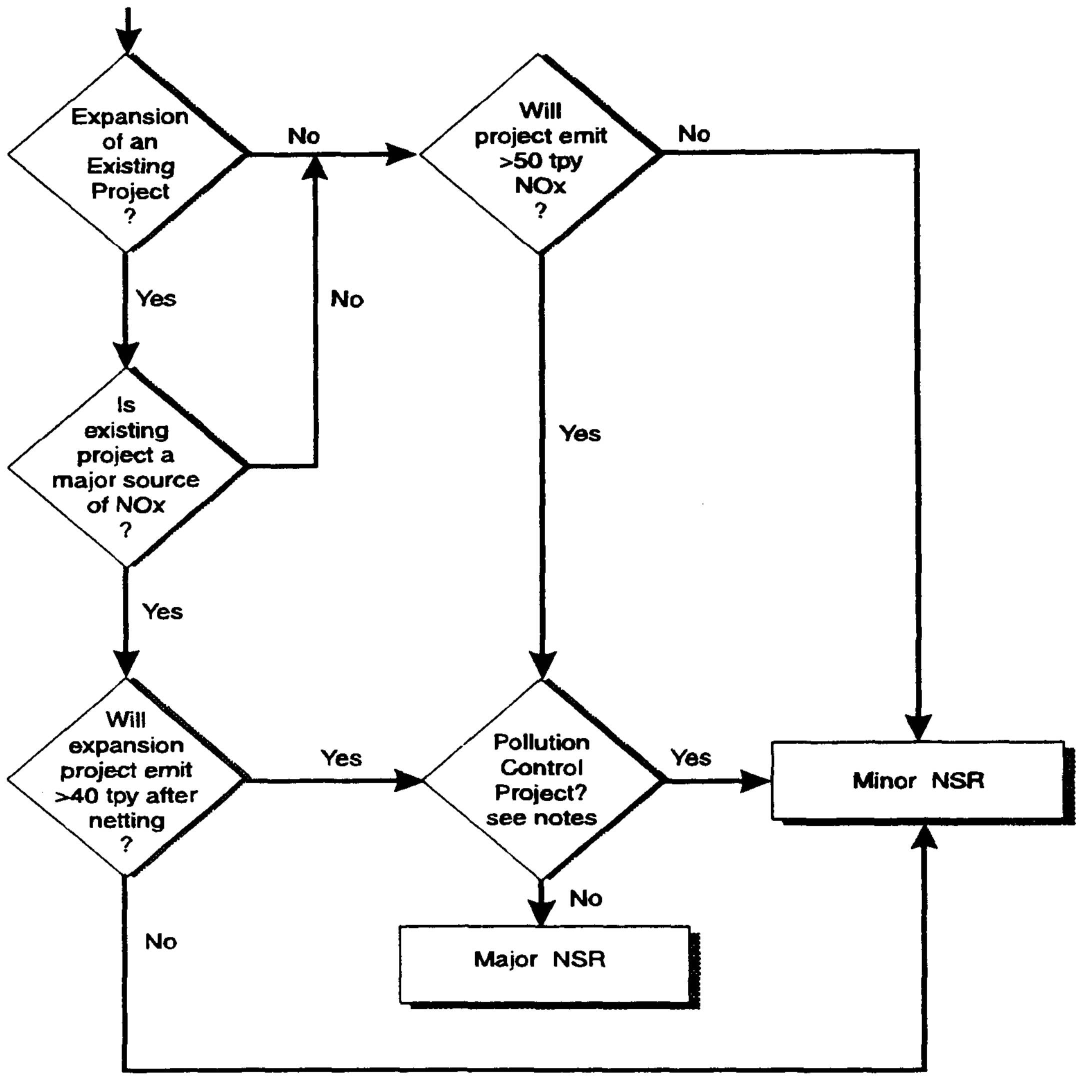
Nonattainment Area Permitting

If a particular area -- usually a county-wide area -- does not meet the NAAQS levels for any of the six criteria pollutants, then it is classified as being in "nonattainment" for that pollutant. A listing of ozone nonattainment areas is provided in Appendix F, since this is the most pervasive nonattainment pollutant and the most likely to affect landfill energy recovery projects. An area may be nonattainment for one or more pollutants. For example, if a county exceeds the NOx levels set by the NAAQS, but meets the standards for the other pollutants, then the area is classified as nonattainment for ozone only (since ozone attainment is regulated through NOx and VOCs).

A proposed new emission source or modification to an existing source located in a nonattainment area must undergo nonattainment major NSR if the source or the modification is classified as major. New sources or modifications are considered major for NOx or CO if they exceed the limits shown in Table 9.2. Figure 9.3 shows a simplified flow diagram for determining whether a new source or modification is major in a serious nonattainment area.

Two primary requirements must be fulfilled in order to obtain a nonattainment NSR permit for criteria pollutants: (1) The project must use technology that achieves the Lowest Achievable Emissions Rate (LAER) for the nonattainment pollutant, and (2) a source must arrange for an emission reduction at an existing combustion source that more than offsets the emissions from the new project.

Figure 9-3 Applicability of New Source Review Requirements in Serious Non-Attainment Areas for Ozone: Emissions of NOx Used as an Example



Notes:

A Pollution Control Project must be both:

(a) *environmentally beneficial; and*
(b) *not cause or contribute to a violation of a NAAQS or PSD increment, or adversely affect an AQRV in a Class I area.*

In addition:

- The permitting authority must determine that the project qualifies as a pollution control project.
- The permitting authority must provide an opportunity for public review and comment on the project's application and the proposed NSR exclusion.

Table 9-2 Nonattainment Area Limits For NOx and CO

Pollutant	**New Sources** are Considered Major if Emissions Exceed (in TPY)	**Modifications to an Existing Minor Source** are Considered Major if Emissions Exceed (in TPY)	**Modifications to an Existing Major Source** are Considered Major if Emissions Exceed (in TPY)
NOx			
Marginal	100	100	40
Moderate	100	100	40
Serious	50	50	40
Severe	25	25	25
Extreme	10	10	10
CO			
Moderate	100	100	100
Serious	50	50	50

Defining the lowest achievable emission rate (LAER) can be a challenge for landfill gas projects. Permitting authorities unfamiliar with the characteristics of landfill gas may expect a landfill gas project to achieve the same LAER as a natural gas project. This can be difficult for a number of reasons, including the inability of the catalysts designed to reduce NOx emissions to function effectively on landfill gas, the variable flow, composition, and Btu value of landfill gas, and the fact that landfill gas projects are often too small for the use of turbines, which have lower NOx rates than IC engines, to be economic. Cost, however, is not a consideration in determining the LAER technology.

Obtaining emission offsets to ensure no net change in overall pollutant levels can also be a challenge. Emission offsets are created when emission reductions are achieved at an existing emissions source (typically, an industrial facility) in order to cover the increased emissions of the new source. The most common type of offsets required by the new projects are NOx offsets because there are many ozone nonattainment areas (i.e. areas whose NOx and VOC levels do not meet NAAQS), and many combustion sources emit NOx at high enough levels to become major sources and require offsets. Most of the northeast U.S. is designated as an ozone nonattainment area, for example, known as the Northeast Ozone Transport Region.

The number of offsets required by a project is determined by applying an offsets ratio to its emission level above the threshold. The ratio varies from 1:1.1 to 1:1.5 for ozone, depending upon an area's degree of nonattainment, and is 1:1 for CO and other criteria pollutants. For example, a project proposed for a severe ozone nonattainment area that has the potential to emit 100 tons per year of NOx would be required to obtain 97.5 tons per year of NOx offsets.[3]

NSR Exemption for Pollution Control Projects

On July 1, 1994, EPA's Office of Air Quality and Planning Standards issued guidance to regional and state staff that increases their flexibility in permitting projects that are classified as "pollution control projects". Under the guidance, the permitting authority may exempt the project from major NSR, as long as emissions from the project and minor source requirements are met. In nonattainment areas, offsets will still be required, but need not exceed a 1:1 ratio. In order to qualify as a pollution control project, a landfill gas-to-energy project must pass two tests: (1) the environmentally-beneficial test and (2) the air quality impact assessment.

Under the environmentally-beneficial test, the proposed project is evaluated on its overall environmental impact on air quality. If, on balance, there is a beneficial impact on air quality, the project could qualify as a pollution control project. For example, a landfill gas-to-energy recovery project could be considered a pollution control project if it reduces VOCs, even if it generates some NOx.

Under the air quality impact assessment, the pollution control exclusion will not apply if the emissions from the project would (e.g. NOx) cause or contribute to a violation of NAAQS or PSD increment, or adversely impact visibility or other Air Quality Related Values (AQRV) in a Class I area [see, e.g., Clean Air Act sections 110(a)(2)(C), 165, 169A(b), 173]. Therefore, where a pollution control project will result in a significant increase in emissions and that increased level has not been previously analyzed for its air quality impact and raises the possibility of a NAAQS, PSD increment, or AQRV violation, the permitting authority is to require the source to provide an air quality analysis sufficient to demonstrate the impact of the project. In the case of non-attainment areas, the State or the source must provide offsetting emissions reductions (at a 1:1 ratio) for any significant increase in a nonattainent pollutant (e.g. NOx) from the pollution control project. However, rather than having to apply offsets on a case-by-case basis, States may consider adopting specific control measures or strategies for the purpose of generating offsets to mitigate the projected collateral emissions increases from a class or category of pollution control projects.

In addition to passing the two tests, there are two procedural safeguards that a pollution control project must address. First, the project must receive approval from the permitting authority (this is done on a case-by-case basis). Second, the application for exclusion and the permitting agency's proposed decision must be subject to public notice with the opportunity for public and EPA written comment.

[3]The number of tons that must be offset is calculated as follows: ["emissions level" (100 tons) *minus* "threshold level for severe nonattainment" (25 tons)] *multiplied by* ["offsets ratio for severe nonattainment" (1.3)].

This guidance memorandum is included in Appendix E. It is important to recognize that this is a guidance document and not a promulgated rule, which means that permitting authorities may choose to adopt the guidance and exercise greater flexibility, or disregard it.

NOx Emissions from Energy Conversion

Combustion of landfill gas -- in an engine, turbine, or other device -- generates nitrogen oxide (NOx). The amount of NOx generated and emitted depends primarily upon the following two characteristics of the combustion process:

- Air/fuel Ratio: the ratio of air to fuel (i.e., landfill gas) in the combustion chamber is a key factor in determining the quantity of NOx generated from combustion of landfill gas. If air in excess of what is needed to achieve combustion is introduced into the combustion chamber, fewer NOx emissions are generated.

- Residence time: the amount of time that the landfill gas is in the combustion chamber has a significant effect on NOx formation. Longer residence times allow greater quantities of NOx to be formed and ultimately emitted.

The air/fuel ratio and residence time vary between the major technologies used in landfill gas-to-energy applications (i.e., internal combustion engines and combustion turbines) as well as among different types of engines; therefore, NOx emissions per cubic foot of landfill gas burned as fuel in a combustion device also varies. When internal combustion engines and turbines are used in conventional natural gas applications, catalysts are often used to reduce NOx emissions. To date, catalysts have not proven effective in landfill gas applications because the impurities found in landfill gas quickly limit the catalysts' ability to control NOx emissions.

Table 9.3 provides emissions factors that can be used to estimate the range of NOx emissions that could be expected from a landfill gas project employing internal combustion engines (IC) or combustion turbines (CT). As the table indicates, the potential emission factors for IC engines span a relatively large range; the lower end of the range is represented by lean-burn engines, which use excess air in the combustion process, while the high end is represented by naturally aspirated IC engines. Depending on the specific type of engine being used, it should be possible to select an appropriate emission factor from within this range. In contrast, only one emission factor is provided for combustion turbines. This factor is appropriate for the most common type of turbine used for landfill gas applications (the Solar Centaur gas turbine).

Table 9-3 Emission Factors By Technology Type

	IC Engine	CT
Emission factor (lb NO_x/MMBtu)	0.22 - 0.54	0.12

Annual NOx emissions can be calculated by multiplying the appropriate emission factor from Table 9.3 by the energy content (in MMBtu/year) of the landfill gas fuel. The energy content can be calculated easily from the landfill gas flow, as follows:

$$\text{Energy Content (Btu/Yr)} = \text{LFG (cfd)} * \frac{\text{Btu}}{\text{cf}} * \frac{\text{365 days}}{\text{yr}}$$

Landfill gas typically contains about 500 Btu per cubic foot. This can be used as a default if the Btu value of landfill gas at a specific site is not known. For a 5 million ton landfill with a gas flow of about 3 million cubic feet per day, the energy content would therefore be calculated as follows:

$$3 \text{ mmcfd} * \frac{500 \text{ Btu}}{\text{cf}} * 365 = 548 * 10^3 \text{ MMBtu/yr}$$

Table 9.4 illustrates a potential range of emissions in tons of NOx per year for typical 1, 5, and 10 million ton landfills. As Table 9.4 illustrates, NOx emissions from IC engines are substantially higher than emissions from CTs. Landfills located in ozone non-attainment areas may therefore find that CTs are the most appropriate technology for medium or larger sized landfill gas projects. The following sections describe the differences among IC engines and between IC engines and CTs that result in the large range of emissions.

Table 9-4 NOx Emissions Table

Landfill Characteristics		Estimated NOx Emissions (TPY)	
Waste in Place (million ton)	Landfill Gas Flow (1000 cfd)	IC Engine	CT
1	642	13 - 32	n/a
5	2988	60 - 147	35
10	5264	106 - 260	60

Internal Combustion Engines - There are two basic types of IC engines: naturally aspirated and lean-burn. Naturally aspirated IC engines draw combustion air and landfill gas through a carburetor in stoichiometric proportions, much the same way that an automobile equipped with a carburetor would draw its air/fuel mixture. Just enough air is drawn into the combustion chamber to ignite the air/landfill gas mix. In addition, residence time in the combustion chamber is relatively long. Therefore, this type of engine emits relatively high levels of NOx, and is represented by the high end of the range shown in Table 9.4. For landfill gas-to-energy recovery projects, this type of engine is best suited for smaller projects in ozone attainment areas.

Lean-burn IC engines combust landfill gas with air in *excess* of the stoichiometric mix. Since this type of engine uses a mixture with excess air, it provides both greater engine power output and fewer NOx emissions than a comparable naturally aspirated engine. This type of engine can be expected to emit NOx emissions on the low end of the range shown in Table 9.4. It should be noted that manufacturers of these engines are continually refining them and that newer, even lower NOx emitting engines are expected to be commercially available soon. In addition, newer, more effective add-on control systems are in development.

Combustion Turbines - CTs utilize large amounts of excess air and have relatively short residence time. These factors combine to greatly reduce the amount of NOx emitted relative to internal combustion engines. These lower emissions may be a significant benefit of using a CT, particularly for medium to large landfill gas energy recovery projects located in ozone non-attainment areas. However, because CTs are not cost-effective at smaller projects (i.e., less than 3 MW), these projects typically do not have the option of using CTs.

9.4 LOCAL ISSUES

Local approval of a project is crucial to its success. This approval refers not only to the granting of permits by local agencies, but also to community acceptance of the project. Strong local sentiment against a project can make permitting difficult, if not impossible.

9.4.1 Zoning and Permitting

Project siting and operation are governed by local jurisdictions (in addition to federal regulations); therefore, it is imperative to work with regulatory bodies throughout all stages of project development in order to minimize permitting delays which cost both time and money. This is especially important since the pollution prevention benefits of landfill gas projects may not initially be considered and because different agencies' rules can often be conflicting [Pacey, Doorn, Thorneloe, 1994].

Zoning/Land Use

The first local issue to be addressed is the compatibility of the project site with community land use specifications. Most communities have a zoning and land use plan that identifies where different types of development are allowed (e.g., residential, commercial, industrial). The local zoning board determines whether or not land use criteria are met by a particular project, and can usually grant variances if conditions warrant.

A landfill gas project site will likely require an industrial zoning classification. One advantage of landfill gas projects is that they are usually located at the landfill site, thus zoning reclassification may not be necessary, especially if the landfill is still active.

Permitting Issues

In addition to land use specifications, local agencies have jurisdiction over a number of other project parameters, such as the following:

Noise – Most local zoning ordinances stipulate the allowable decibel levels for noise sources, and these levels vary, depending on the zoning classification at the source site (e.g., a site located near residential areas will have a lower decibel requirement than one located in an isolated area). Even enclosed facilities are usually required to meet these requirements; therefore, it is important to keep them in mind when designing project facilities.

Condensate – There may be unique permitting or treatment requirements for landfill gas condensate. While some landfill gas projects can return the condensate to the landfill, many dispose of condensate through the public sewage system after some form of on-site treatment [Berenyi and Gould, 1994]. It is possible that the condensate may contain high enough quantities of heavy metals and organic chemicals for it to be classified as a hazardous waste, thus triggering additional, federal regulation.

Wastewater – The primary types of wastewater likely to be generated by a landfill gas power project include maintenance/cleaning wastewater, domestic wastewater, and cooling tower blowdown. The municipal engineer's office should be contacted to provide information about available wastewater handling capacity, and any unique condensate treatment requirements or permits for landfills. The wastewater treatment facility operator is likely to have standards governing the pollutant concentrations in incoming wastewater streams. For projects that intend to discharge wastewater into rivers, lakes, or other surface water (typically only the large power projects that use a steam cycle), a National Pollution Discharge Elimination System (NPDES) permit will be required. The authority to issue these permits is delegated to state governments by the U.S. EPA.

Water – Water requirements will depend on the type and size of the project and the environmental control technologies used. The city engineer's office should also be able to provide data about available water supply capacity. If current facilities cannot meet the needs of the project, then new facilities (e.g., pipeline, pumping capacity, wells) may need to be constructed. Groundwater permits could be required if new wells are needed to supply the project's water needs. (Note that the landfill itself, if active, will already be required by RCRA Subtitle D to monitor groundwater.)

Solid waste disposal – The only solid wastes generated by a landfill gas power project will likely be packaging materials, cleaning solvents, and equipment fluids. While there may only be a small amount of solid waste generated, it must be properly disposed of; which may be an important consideration if the project landfill is closed.

Stormwater management – Public works departments regulate stormwater management, and will require a permit for discharges during construction and operation. Good facility design that maintains the predevelopment runoff characteristics of the site will allow the project to easily meet permitting requirements.

Stack height – Local codes may limit stack heights, especially near airports or landing fields. Project design (e.g., plant layout, flare design) must take these limits into account.

Other – There may be other issues that local agencies oversee. It is important to find out what these issues are by contacting local authorities, especially since they vary among project sites. As an example of such other issues, Box 9.1 partially lists the local permits that were required for the Fresh Kills Landfill Methane Recovery Project, located in New York.

9.4.2 Community Acceptance

As any project developer will attest, community support is extremely important to the success of a project, especially since some communities require public participation in project zoning/siting cases. Like landfills, many power projects in the past have encountered local opposition such as the "not in my backyard (NIMBY)" syndrome, or false perceptions of project dangers (e.g., explosion risks, adverse health effects from electromagnetic fields). Therefore, it is important to educate the public and to develop a working relationship with the host community in order to dispel any fears or doubts about the expected impact of the project. Project details should always be presented in a very forthcoming and factual manner.

Landfill gas-to-energy projects bring many benefits to the host community (e.g., improved air quality, reduction of landfill gas odor and explosive potential). These benefits should be emphasized during the permitting process.

Box 9-1 Some of the Local Permits Required for the Fresh Kills Landfill Methane Recovery Project

Agency	Permits
Bureau of Gas and Electricity	Certification that all equipment is explosion proof
Division of Fire Protection	One hundred percent x-ray of all pipe joints
Department of Sanitation	Site approval
Board of Standards and Appeals	Approval of equipment on site
Community Planning Board of Staten Island	Compliance with height restrictions
Department of Environmental Protection	Air Quality approval
Department of Ports and Terminal	Well permits
Department of Buildings	Construction approvals

Source: "Regulatory Barriers to Landfill Gas Recovery Projects"

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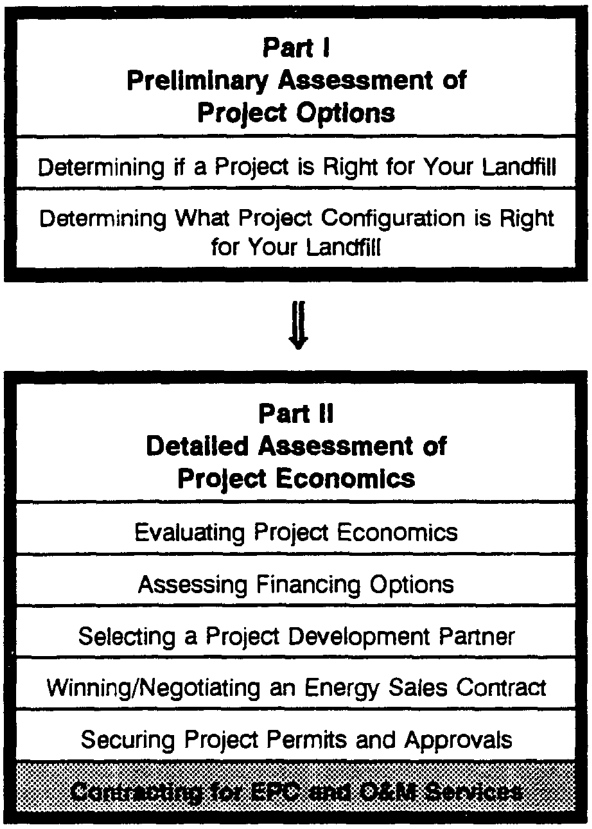
10. Contracting For EPC And O&M Services

As discussed in Chapter 7, many landfill owners may decide to work with firms with extensive experience during project development. Likewise, because the construction and operation of landfill gas energy recovery projects are complex processes, they may be best managed by a firm with proven experience, gained over the course of implementing similar landfill gas projects. Landfill owners that choose to contract with an engineering, procurement, and construction (EPC) firm and/or an operating firm should be aware of some of the basic elements of effective contracting. This chapter provides some contracting considerations for landfill owners, and lists operating insights gained from a survey of technical literature and interviews with landfill energy project owners, developers, and operators.

The Project Development Process



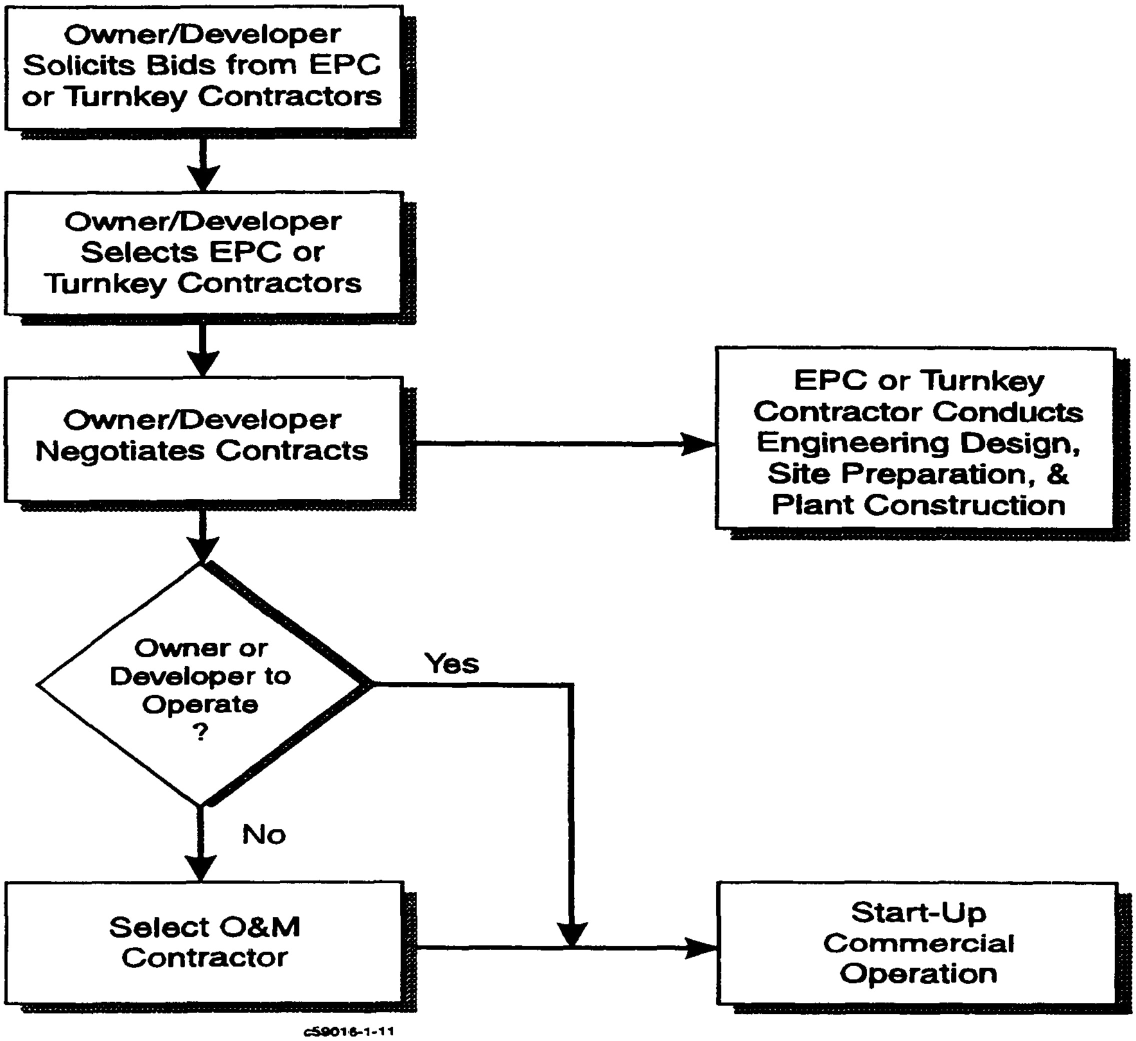
10.1 EPC/Turnkey Contracting

After a project proponent has secured an energy sales contract and the required permits and approvals, he or she may contract with an EPC or turnkey firm who will take responsibility for construction of the project. The tasks performed by an EPC contractor include: conducting engineering design, procuring the equipment, preparing the project site for construction, and pre-operation start-up testing. A turnkey contractor extends its services beyond those of an EPC contractor by taking on many of the owner's and developer's duties as well, which include environmental permitting, regulatory licensing, interconnections, and project management.

The process of contracting with an EPC or turnkey firm is charted in Figure 10.1. As this figure shows, the process has several key steps, beginning with the landfill owner and/or project developer soliciting bids from contractors and ending with the selection of a contractor who will take the project to commercial operation. Along the way, the owner/developer and its chosen contractor must conduct engineering design, site preparation, and plant construction.

An effective EPC or turnkey contract clearly establishes the responsibilities of each contracting entity, and it also should mesh with other existing project documents. The contractor is generally responsible for engineering and building the plant to predetermined specifications, making sure that project construction milestones are met, and ensuring that acceptable performance is achieved at the commercial operation date. The landfill owner

Figure 10-1 The EPC/Turnkey Contracting Process



and/or project developer is generally responsible for making sure funds are available as needed, that the site is available and ready, and that provisions are made for any necessary interconnections related to gas utilization. The elements of an effective contract are described in Table 10.1.

Because of the importance of securing and fulfilling the power sales agreement, the EPC contract should specifically recognize each entity's role in meeting its key elements. These elements include:

Table 10-1 Elements of an Effective EPC or Turnkey Contract

Element	Items to be Specified
Commercial operation date	Date on which facility should achieve commercial operation (should precede date in Power Sales Agreement (PSA))
Milestones	Engineering completion, construction commencement, engine delivery, start-up
Cost, rates, and fees	Structures include: fixed EPC or turnkey price, hourly labor rates, cost caps, fee amount or percentage
Performance guarantees	Specified output (kW, mcf), heat rate, availability, power quality, gas quality (should match PSA)
Warranties	Output, performance degradation, heat rate, outage rates, component replacement costs
Owner's acceptance criteria and procedure	Testing methods and conditions, calculation formulae
Bonus amounts and conditions	Bonus for early completion, exceeding specifications
Liquidated damages and conditions	Damages for late completion, failure to meet specifications
Assignment	Ability to assign agreement to subsidiary, partnership, bank

- Commercial operation date;
- Project output (e.g., kW electricity, mcf gas) and heat rate;
- Plant availability; and
- Interconnection requirements; and
- Maintenance provisions.

Power project developers usually prefer to sign fixed-price EPC or turnkey agreements, which enable the plant's installed cost to be known up front. If a fixed-price contract is selected, then the price, scope of services, and other terms must be clearly specified in the contract. The contract price should have an underlying budget that includes plant components as well as the services mentioned above. The most important budget items are listed in Box 10.1.

Contracting with a turnkey plant provider is an extension of contracting for EPC services, because the turnkey provider usually agrees to include within its scope of services the owner's and developer's duties as well as EPC contracting. A turnkey plant provider is usually an EPC firm or developer who agrees to develop and build a facility for a fixed price. As shown in Table 10.1, a turnkey contract must include the following items that are in addition to the typical EPC contract items: turnkey price, development milestones, and contractor's responsibilities.

Box 10.1 EPC and Turnkey Budget Items

The EPC budget for a landfill gas energy recovery project should include at least the following items:

- Engine skid (e.g., IC engine, CT, turbine/generator)
- Engine auxiliaries (e.g., lubricating oil system, cooling system, air intake manifold and filters, intake and exhaust silencers, fuel injection system, hydraulic system, piping, and ductwork)
- Foundations and sitework
- Gas processing system (e.g., filters, refrigeration)
- Gas compressor(s)
- Emissions controls
- Plant electrical equipment and switchgear
- Step up transformer(s)
- Interconnections (electric, water, landfill gas)
- Back-up fuel capability/storage
- Automatic control system
- Gas and electric metering
- Water treatment and cooling
- Building/enclosure
- Fire protection system
- Engineering costs and associated expenses
- EPC contingency

A turnkey facility provider should include the following additional items:

- Gas collection system (if applicable)
- Additional interconnection costs (e.g., rights-of-way, piping, transmission lines)
- Permitting costs, legal, administration expenses, insurance
- Financing costs (if applicable)
- Escalation during construction
- Interest during construction
- Contingency
- Fee

10.2 O&M Services Contracting

Many landfill owners and/or project developers do not wish to take on the day-to-day responsibility of operating their landfill gas energy recovery project due to lack of manpower, experience, or desire. When this is the case, hiring an O&M contractor may be an attractive alternative. A survey of existing and planned landfill gas energy recovery projects shows that about 80% of gas collection systems and 89% of gas processing/energy recovery systems are operated by private O&M firms or in partnership with a private O&M firm [Berenyi and Gould, 1994].

When contracting with the provider of O&M services, the landfill owner should talk to several competing companies and select a winner based on experience, price, and terms. The O&M company should have experience operating and maintaining similar facilities, and should demonstrate that its accumulated experience will be applied in the form of qualified personnel and ongoing training activities. Competing O&M companies should be asked to submit hourly rates, expected annual budgets for O&M services, and fees.

It is important that the scope of O&M services be well defined so all bids can be compared on a consistent basis. For example, it should be clearly specified whether O&M services are to be provided for the gas collection system and the energy recovery system both or only for one. The EPC contractor or equipment vendor can usually supply estimates for the costs and duration of periodic maintenance procedures and major overhauls.

The facility owner may choose to provide incentives to the O&M company in the form of contractual bonus/damages clauses to improve performance. For example, if maximizing annual operating hours is important to project economics, then the facility owner might propose a cash bonus for plant availability or kWh generation which exceeds a predetermined amount.

10.3 GOOD O&M PRACTICES

The power production and direct use technologies for landfill gas have been improved since their first use about 15 years ago. Over this time, many of the operational problems encountered have been addressed with technology or procedural improvements. Therefore, many of the technical problems found in the landfill gas literature are no longer major obstacles to successful landfill gas energy recovery (in fact, some of the problems are no longer obstacles at all).

In a recent survey, however, at least 22% of operating landfill gas energy recovery projects reported experiencing operating interruptions for reasons other than planned maintenance [Berenyi and Gould, 1994]. Of the 29 plants that reported unplanned interruptions, only two experienced problems resulting in plant failure. The main reason cited for interruptions was gas collection or processing equipment problems. Other specific operational problems related to the gas collection system causing plant interruptions include pipe blockage or breakage and lack of landfill gas. In many cases, such problems can be avoided with careful equipment selection and operation and maintenance. Good O&M procedures are always important to the success of energy projects. They are even more important with landfill gas projects due to the impurities and variability found in landfill gas. This section presents insights on how to prevent or minimize operating problems.

10.3.1 Collection Systems

Before sizing an energy recovery project, a project developer should estimate landfill gas quantity as accurately as possible to prevent oversizing the equipment and inefficiencies due to gas shortfall during operation. After project start up, proper operation and maintenance of the gas collection system is necessary to balance offsite gas migration control with optimal equipment performance.

Collection system problems may occur when wellfields are located in active landfill areas; therefore, it is important to account for future landfill operations when designing the collection system. By planning ahead, plant shutdowns or reduced output levels due to collection system repairs may be avoided. Two examples of potential problems that may be prevented by good planning are:

- Decreased gas recovery rates due to limited well accessibility caused by depositing additional refuse vertically on top of existing wells [WMNA, 1992];

- Reduced landfill gas generation and quality caused by reopening a section of inactive landfill where an existing well is located.

Good operating procedures, in addition to good system design, will also help to prevent problems. For example, routine monitoring and tuning of wells will ensure that gas quality is suitable for the efficient operation of the recovery equipment.

10.3.2 Energy Recovery Systems

While energy recovery technologies have been adapted to landfill gas applications, several important operating considerations must be kept in mind to minimize or avoid problems that arise due to landfill gas's corrosive nature and low Btu content.

IC Engines

IC engines are the most susceptible of the three common electric generation technologies to the effects of corrosion [Anderson], which attacks engine parts and causes deposit buildup. Experience has shown the following steps to be useful in combatting corrosion in IC engines used at landfills:

- Perform frequent oil checks and changes.

- Use an oil with a high alkalinity reserve (i.e., oil with a high total base number) [Schleifer, 1988]. Oils with a total base number (TBN) of 10 are commonly used [WMNA, 1992].

- Use oil filters that have been treated with chemicals to neutralize acids from the combustion of landfill gas [Anderson].

- Chrome-plate components that are subject to attack [Pacey, Doorn, and Thorneloe, 1994].

CTs and Boiler/Steam Turbines

Although CTs and boiler/steam turbines are more resistant to corrosion than engines, they each have their own set of operational considerations:

- An extra filtration step may be necessary if the compressors used to reach the required pressure for CT operation cause oil entrainment and heating of the landfill gas [WMNA, 1992].

- Due to the Btu variability in landfill gas, CT fuel/air controls must react very quickly. If they do not, the temperature will overshoot and automatically shut down the CT. To avoid temperature overshoot, landfill gas fueled-CTs should be operated at a lower temperature setpoint than CTs using conventional fuels [Pacey, Doorn, and Thorneloe, 1994].

- Silica deposits, which can lead to turbine failure, can be prevented with gas refrigeration to condense dimethyl siloxane before combustion; however, this step may not be economically justified [Anderson, WMNA, 1992].

- Boiler tubes should be designed to withstand the corrosiveness of landfill gas.

The over 200 existing and planned landfill gas energy recovery projects illustrate that the technology is well-demonstrated and generally reliable. As long as projects are well planned, executed, and maintained, they can perform up to or beyond expectations for many years.

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APPENDIX A

CALCULATIONS OF LANDFILL GAS ENERGY RECOVERY PROJECT COSTS

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This Appendix contains sample cost estimates and calculations for three landfill sizes--1, 5, and 10 million metric tons of waste in place. The cost data are intended to illustrate the types of cost items that should be included when evaluating project economics. The actual costs of a specific project are dependent on project configuration, design, equipment selection, location, and site-specific factors. Thus, a qualified engineer should be consulted when considering investing in a landfill gas energy recovery project.

This Appendix contains 20 tables. Tables A.1 through A.14 present costs and calculations for a landfill gas power project, and Tables A.15 through A.20 present costs and calculations for a medium-Btu gas project. Tables A.1 through A.10 contain capital and O&M cost information for each of the landfill sizes. The remainder of the power project tables--Tables A.11 through A.14--contain sample comparisons of expenses and revenues for a 5 million metric ton landfill power project. Project finance and municipal bond finance cases are included.

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TABLE A.1 SUMMARY OF ESTIMATED POWER PROJECT CAPITAL COSTS

LANDFILL SIZE Waste in Place	Estimated Net Sustainable LFG Production (mcf/day)	Net Electric Output (kW)	CAPITAL COSTS Installed LFG Collection System ($/kW)	Installed Energy Conversion System ($/kW)	Total Soft Costs + Engineering ($/kW) (a)	Total Capital Requirement ($/kW)	Incremental Capital Requirement ($/kW) (b)
1 million metric tons							
IC Engine	642	984	$638	$1,052	$310	$2,000	$1,283
Combustion Turbine	642	963	$652	$1,412	$359	$2,423	$1,691
5 million metric tons							
IC Engine	2,988	4,934	$423	$958	$294	$1,675	$1,177
Combustion Turbine	2,988	4,727	$442	$1,153	$334	$1,928	$1,409
Combined Cycle CT	2,988	6,763	$309	$1,360	$356	$2,025	$1,658
10 million metric tons							
IC Engine	5,266	8,709	$413	$919	$263	$1,595	$1,109
Combustion Turbine	5,266	8,344	$431	$1,037	$288	$1,756	$1,249
Combined Cycle CT	5,266	12,008	$300	$1,208	$306	$1,813	$1,458

Notes:

Source is cost calculation tables for each size landfill.

All costs are based on net electric (kW) output.

(a) Included are owners' costs (legal, permitting, insurance, taxes), escalation during construction (6 – 24 mos) and interest during construction.

(b) Excludes capital and soft costs associated with the LFG collection system.

TABLE A.2 ESTIMATED CAPITAL COSTS (1 million Mg case)

Example: Landfill waste in place = 1 million metric tons

Cost Category	Units	IC Engine	Combustion Turbine	
OPERATING DATA				
Net sustainable landfill gas production	mcf/day	642	642	(a)
Gross electric output	kW	1,029	1,029	(b)
Auxiliary and compressor loads	kW	46	66	(c)
Net electric output	kW	984	963	
On-line date		6/96	6/96	
Capacity factor (lifetime annual average)		80%	80%	(d)
Annual full load operating hours	hours	7,008	7,008	
Annual electricity generated	kWh	6,895,872	6,748,704	
EQUIPMENT & INSTALLATION COSTS				
Energy Conversion System ($1994)				
Engine, auxiliaries, construction	$000	825	1,050	(e)
Interconnections (elec, water, LFG)	$000	110	110	(f)
Gas compressor	$000	100	200	
Energy conversion system cost	$000	1,035	1,360	
LFG collection system cost ($1994)	$000	628	628	(g)
Engineering ($1994) @ 5.0%	$000	83	99	(h)
CAPITAL REQUIREMENT				
System cost ($1994)	$000	1,746	2,087	
Soft Costs				
Owners costs, escalation, interest		135	142	(i)
Contingency @ 5.0%		87	104	
Total Soft Costs	$000	222	246	
Total Capital Requirement	$000	**1,968**	**2,333**	
(as-spent dollars, 1996 on-line date)	$/kW net	**2,000**	**2,423**	
Incremental Capital Requirement	$000	**1,263**	**1,628**	(j)
(as-spent dollars, 1996 on-line date)	$/kW net	**1,283**	**1,691**	

Notes:

(a) Based on landfill size of approximately 1 million metric tons. [EPA] (mcf = thousand cubic feet)
1 cf landfill gas = 0.5 cf methane

(b) kW = (cf/hr methane) x (1000 Btu/cf) / (13,000 Btu/kWh)

(c) Compressor effects: IC engine--2% parasitic load; CTs--4% parasitic load

(d) Conservative estimated capacity factor over project life. [EPA]

(e) Includes prime mover, generator, plant auxiliaries, construction, LFG modifications, emissions controls.

(f) Assumed to be $100,000 for electric, $10,000 for water.

(g) Calculated based on EPA Exhibit 4-7; includes collection system + flare. [EPA]

(h) Calculated as 5% of conversion and collection system costs.

(i) Included are owners' costs (legal, permitting, insurance, taxes), escalation during construction (6 mos) and interest during construction.

(j) Excludes capital and soft costs associated with the LFG collection system.

TABLE A.3 ESTIMATED COST OF ELECTRICITY (1 million Mg case)
Project Finance Case

Example: Landfill waste in place = 1 million metric tons

Cost Category	Units	IC Engine	Combustion Turbine	
POWER PROJECT COSTS				
Capital Costs (as–spent, 1996 online)				
Conversion system + collection system	$/kW	2,000	2,423	
Conversion system only	$/kW	1,283	1,691	
O&M Costs (1996)				
LFG collection system	c/kWh	1.2	1.2	(a)
Conversion system	c/kWh	1.8	1.5	(b)
Royalty Payments (1996)	c/kWh	0.5	0.5	(c)
FIRST YEAR COST OF ELECTRICITY (1996)				
Capital charge rate (project finance)		0.136	0.136	(d)
Total Electricity Cost				
Levelized capacity price	c/kWh	3.9	4.7	(e)
1996 O&M price	c/kWh	3.0	2.7	
Royalty Payment	c/kWh	0.5	0.5	
Total 1996 cost of electricity	c/kWh	7.4	7.9	
Incremental Electricity Cost				(f)
Levelized capacity price	c/kWh	2.5	3.3	(e)
1996 O&M price	c/kWh	1.8	1.5	
Royalty Payment	c/kWh	0.5	0.5	
Total 1996 cost of electricity	c/kWh	4.8	5.3	

Notes:

(a) Based on EPA estimate for collection + flare systems (Exhibit 4–7), in $1996. [EPA]

(b) Based on O&M estimates published by Wolfe & Maxwell in "Commercial Landfill Recovery Operations–Technology and Economics," and in EPA Report to Congress (Exhibit 4–7).

(c) Royalty payments to the landfill owner are estimated to be 10% of revenues (4.9 c/kWh).

(d) Assumes: 20–year life, project finance with a 80/20 debt/equity ratio, 9% interest on debt; includes 15% return on equity; 10–year depreciation.

(e) Calculated by multiplying capital $/kW by CCR and dividing by annual hours of operation.

(f) Conversion system only cost does not include capital and O&M costs associated with LFG collection system.

TABLE A.4 ESTIMATED COST OF ELECTRICITY (1 million Mg case) Municipal Bond Finance Case

Example: Landfill waste in place = 1 million metric tons

Cost Category	Units	IC Engine	Combustion Turbine	
POWER PROJECT COSTS				
Capital Costs (as−spent, 1996 online)				
Conversion system + collection system	$/kW	2,000	2,423	
Conversion system only	$/kW	1,283	1,691	
O&M Costs (1996)				
LFG collection system	c/kWh	1.2	1.2	(a)
Conversion system	c/kWh	1.8	1.5	(b)
Royalty Payments (1996)	c/kWh	0.5	0.5	(c)
FIRST YEAR COST OF ELECTRICITY (1996)				
Capital charge rate (muni bond finance)		0.111	0.111	(d)
Total Electricity Cost				
Levelized capacity price	c/kWh	3.2	3.8	(e)
1996 O&M price	c/kWh	3.0	2.7	
Royalty Payment	c/kWh	0.5	0.5	
Total 1996 cost of electricity	c/kWh	6.7	7.0	
Incremental Electricity Cost				(f)
Levelized capacity price	c/kWh	2.0	2.7	(e)
1996 O&M price	c/kWh	1.8	1.5	
Royalty Payment	c/kWh	0.5	0.5	
Total 1996 cost of electricity	c/kWh	4.3	4.7	

Notes:

(a) Based on EPA estimate for collection + flare systems (Exhibit 4−7), in $1996. [EPA]

(b) Based on O&M estimates published by Wolfe & Maxwell in "Commercial Landfill Recovery Operations−Technology and Economics," and in EPA Report to Congress (Exhibit 4−7).

(c) Royalty payments to the landfill owner are estimated to be 10% of revenues (4.9 c/kWh).

(d) Assumes tax−exempt municipal bond financing at 6.5%.

(e) Calculated by multiplying capital $/kW by CCR and dividing by annual hours of operation.

(f) Conversion system only cost does not include capital and O&M costs associated with LFG collection system.

TABLE A.5 ESTIMATED CAPITAL COSTS (5 million Mg case)

Example: Landfill waste in place = 5 million metric tons

Cost Category	Units	IC Engine	Combustion Turbine	Combined Cycle CT	
OPERATING DATA					
Net sustainable landfill gas production	mcf/day	2,988	2,988	2,988	(a)
Gross electric output	kW	5,188	5,188	7,324	(b)
Auxiliary and compressor loads	kW	254	461	561	(c)
Net electric output	kW	4,934	4,727	6,763	
On-line date		6/96	6/96	6/96	
Capacity factor (lifetime annual average)		80%	80%	80%	(d)
Annual full load operating hours	hours	7,008	7,008	7,008	
Annual electricity generated	kWh	34,577,472	33,126,816	47,395,104	
EQUIPMENT & INSTALLATION COSTS					
Energy Conversion System ($1994)					
Engine, auxiliaries, construction	$000	4,075	4,300	7,950	(e)
Interconnections (elec, water, LFG)	$000	400	400	500	(f)
Gas compressor	$000	250	750	750	
Energy conversion system cost	$000	4,725	5,450	9,200	
LFG collection system cost ($1994)	$000	2,088	2,088	2,088	(g)
Engineering ($1994) @ 5.0%	$000	341	377	564	(h)
CAPITAL REQUIREMENT					
System cost ($1994)	$000	7,154	7,915	11,853	
Soft Costs					
Owners costs, escalation, interest		751	804	1,248	(i)
Contingency @ 5.0%		358	396	593	
Total Soft Costs	$000	1,109	1,200	1,841	
Total Capital Requirement	$000	**8,263**	**9,115**	**13,694**	
(as-spent dollars, 1996 on-line date)	$/kW net	**1,675**	**1,928**	**2,025**	
Incremental Capital Requirement	$000	**5,807**	**6,659**	**11,216**	(j)
(as-spent dollars, 1996 on-line date)	$/kW net	**1,177**	**1,409**	**1,658**	

Notes:

(a) Based on landfill size of approximately 5 million metric tons. [EPA] (mcf = thousand cubic feet)
1 cf landfill gas = 0.5 cf methane

(b) kW = (cf/hr methane) x (1000 Btu/cf) / (generator Btu/kWh)

(c) Compressor effects: IC engine--2% parasitic load; CTs--6% parasitic load

(d) Conservative estimated capacity factor over project life. [EPA]

(e) Includes prime mover, generator, plant auxiliaries, construction, LFG modifications, emissions controls.

(f) Assumed to be $350,000 to $450,000 for electric, $50,000 for water.

(g) Calculated based on EPA Exhibit 4-7; includes collection system + flare. [EPA]

(h) Calculated as 5% of conversion and collection system costs.

(i) Included are owners' costs (legal, permitting, insurance, taxes), escalation during construction (12 - 18 mos) and interest during construction.

(j) Excludes capital and soft costs associated with the LFG collection system.

TABLE A.6 ESTIMATED COST OF ELECTRICITY (5 million Mg case)
Project Finance Case

Example: Landfill waste in place = 5 million metric tons

Cost Category	Units	IC Engine	Combustion Turbine	Combined Cycle CT	
POWER PROJECT COSTS					
Capital Costs (as-spent, 1996 online)					
Conversion system + collection system	$/kW	1,675	1,928	2,025	
Conversion system only	$/kW	1,177	1,409	1,658	
O&M Costs (1996)					
LFG collection system	c/kWh	0.5	0.5	0.5	(a)
Conversion system	c/kWh	1.8	1.5	1.6	(b)
Royalty Payments (1996)	c/kWh	0.5	0.5	0.5	(c)
FIRST YEAR COST OF ELECTRICITY (1996)					
Capital charge rate (project finance)		0.136	0.136	0.136	(d)
Total Electricity Cost					
Levelized capacity price	c/kWh	3.2	3.7	3.9	(e)
1996 O&M price	c/kWh	2.3	2.0	2.1	
Royalty payment	c/kWh	0.5	0.5	0.5	
Total 1996 cost of electricity	c/kWh	6.0	6.2	6.5	
Incremental Electricity Cost					(f)
Levelized capacity price	c/kWh	2.3	2.7	3.2	(e)
1996 O&M price	c/kWh	1.8	1.5	1.6	
Royalty payment	c/kWh	0.5	0.5	0.5	
Total 1996 cost of electricity	c/kWh	4.6	4.7	5.3	

Notes:

(a) Based on EPA estimate for collection + flare systems (Exhibit 4-7), in $1996. [EPA]
(b) Based on O&M estimates published by Wolfe & Maxwell in "Commercial Landfill Recovery Operations—Technology and Economics," and in EPA Report to Congress (Exhibit 4-7).
(c) Royalty payments to the landfill owner are estimated to be 10% of revenues (4.9 c/kWh).
(d) Assumes: 20-year life, project finance with a 80/20 debt/equity ratio, 9% interest on debt; includes 15% return on equity; 10-year depreciation.
(e) Calculated by multiplying capital $/kW by CCR and dividing by annual hours of operation.
(f) Incremental Electricity Cost does not include capital and O&M costs associated with LFG collection system.

TABLE A.7 ESTIMATED COST OF ELECTRICITY (5 million Mg case) Municipal Bond Finance Case

Example: Landfill waste in place = 5 million metric tons

Cost Category	Units	IC Engine	Combustion Turbine	Combined Cycle CT	
POWER PROJECT COSTS					
Capital Costs (as-spent, 1996 online)					
Conversion system + collection system	$/kW	1,675	1,929	2,025	
Conversion system only (incremental)	$/kW	1,177	1,409	1,658	
O&M Costs (1996)					
LFG collection system	c/kWh	0.5	0.5	0.5	(a)
Electric generation system	c/kWh	1.8	1.5	1.6	(b)
Royalty Payments (1996)	c/kWh	0.5	0.5	0.5	(c)
FIRST YEAR COST OF ELECTRICITY (1996)					
Capital charge rate (muni bond finance)		0.111	0.111	0.111	(d)
Total Electricity Cost					
Levelized capacity price	c/kWh	2.7	3.1	3.2	(e)
1996 O&M price	c/kWh	2.3	2.0	2.1	
Royalty payment	c/kWh	0.5	0.5	0.5	
Total 1996 cost of electricity	c/kWh	5.5	5.6	5.8	
Incremental Electricity Cost					(f)
Levelized capacity price	c/kWh	1.9	2.2	2.6	(e)
1996 O&M price	c/kWh	1.8	1.5	1.6	
Royalty payment	c/kWh	0.5	0.5	0.5	
Total 1996 cost of electricity	c/kWh	4.2	4.2	4.7	

Notes:

(a) Based on EPA estimate for collection + flare systems (Exhibit 4-7), in $1996. [EPA]
(b) Based on O&M estimates published by Wolfe & Maxwell in "Commercial Landfill Recovery Operations-Technology and Economics," and in EPA Report to Congress (Exhibit 4-7).
(c) Royalty payments to the landfill owner are estimated to be 10% of revenues (4.9 c/kWh).
(d) Assumes tax-exempt municipal bond financing at 6.5%.
(e) Calculated by multiplying capital $/kW by CCR and dividing by annual hours of operation.
(f) Incremental Electricity Cost does not include capital and O&M costs associated with LFG collection system.

TABLE A.8 ESTIMATED CAPITAL COSTS (10 million Mg case)

Example: Landfill waste in place = 10 million metric tons

Cost Category	Units	IC Engine	Combustion Turbine	Combined Cycle CT	
OPERATING DATA					
Net sustainable landfill gas production	mcf/day	5,266	5,266	5,266	(a)
Gross electric output	kW	9,142	9,142	12,907	(b)
Auxiliary and compressor loads	kW	433	799	899	(c)
Net electric output	kW	8,709	8,344	12,008	
On-line date		6/96	6/96	6/96	
Capacity factor (lifetime annual average)		80%	80%	80%	(d)
Annual full load operating hours	hours	7,008	7,008	7,008	
Annual electricity generated	kWh	61,032,672	58,474,752	84,152,064	
EQUIPMENT & INSTALLATION COSTS					
Energy Conversion System ($1994)					
Engine, auxiliaries, construction	$000	7,200	7,350	13,100	(e)
Interconnections (elec, water, LFG)	$000	400	400	500	(f)
Gas compressor	$000	400	900	900	
Energy conversion system cost	$000	8,000	8,650	14,500	
LFG collection system cost ($1994)	$000	3,599	3,599	3,599	(g)
Engineering ($1994) @ 5.0%	$000	580	612	905	(h)
CAPITAL REQUIREMENT					
System cost ($1994)	$000	12,179	12,861	19,004	
Soft Costs					
Owners costs, escalation, interest		1,103	1,150	1,820	(i)
Contingency @ 5.0%		609	643	950	
Total Soft Costs	$000	1,711	1,793	2,770	
Total Capital Requirement	$000	**13,890**	**14,654**	**21,774**	
(as-spent dollars, 1996 on-line date)	$/kW net	**1,595**	**1,756**	**1,813**	
Incremental Capital Requirement	$000	**9,658**	**10,422**	**17,504**	(j)
(as-spent dollars, 1996 on-line date)	$/kW net	**1,109**	**1,249**	**1,458**	

Notes:

(a) Based on landfill size of approximately 5 million metric tons. [EPA] (mcf = thousand cubic feet)
1 cf landfill gas = 0.5 cf methane

(b) Calculated according to EPA formula: kW = (cf/hr methane) x (1000 Btu/cf) / generator Btu/kWh)

(c) Compressor effects: IC engine--2% parasitic load; CTs--6% parasitic load

(d) Conservative estimated capacity factor over project life. [EPA]

(e) Includes prime mover, generator, plant auxiliaries, construction, LFG modifications, emissions controls.

(f) Assumed to be $350,000 to $450,000 for electric, $50,000 for water.

(g) Calculated based on EPA Exhibit 4-7; includes collection system + flare. [EPA]

(h) Calculated as 5% of conversion and collection system costs.

(i) Included are owners' costs (legal, permitting, insurance, taxes), escalation during construction (18 mos) and interest during construction.

(j) Excludes capital and soft costs associated with the LFG collection system.

TABLE A.9 ESTIMATED COST OF ELECTRICITY (10 million Mg case)
Project Finance Case

Example: Landfill waste in place = 10 million metric tons

Cost Category	Units	IC Engine	Combustion Turbine	Combined Cycle CT	
POWER PROJECT COSTS					
Capital Costs (as-spent, 1996 online)					
Conversion system + collection system	$/kW	1,595	1,756	1,813	
Conversion system only	$/kW	1,109	1,249	1,458	
O&M Costs (1996)					
LFG collection system	c/kWh	0.4	0.4	0.4	(a)
Conversion system	c/kWh	1.8	1.3	1.5	(b)
Royalty Payments (1996)	c/kWh	0.5	0.5	0.5	(c)
FIRST YEAR COST OF ELECTRICITY (1996)					
Capital charge rate (project finance)		0.136	0.136	0.136	(d)
Total Electricity Cost					
Levelized capacity price	c/kWh	3.1	3.4	3.5	(e)
1996 O&M price	c/kWh	2.2	1.7	1.9	
Royalty Payment	c/kWh	0.5	0.5	0.5	
Total 1996 cost of electricity	c/kWh	5.8	5.6	5.9	
Incremental Electricity Cost					(f)
Levelized capacity price	c/kWh	2.2	2.4	2.8	(e)
1996 O&M price	c/kWh	1.8	1.3	1.5	
Royalty Payment	c/kWh	0.5	0.5	0.5	
Total 1996 cost of electricity	c/kWh	4.5	4.2	4.8	

Notes:

(a) Based on EPA estimate for collection + flare systems (Exhibit 4-7), in $1996. [EPA]

(b) Based on O&M estimates published by Wolfe & Maxwell in "Commercial Landfill Recovery Operations-Technology and Economics," and in EPA Report to Congress (Exhibit 4-7).

(c) Royalty payments to the landfill owner are estimated to be 10% of revenues (4.9 c/kWh).

(d) Assumes: 20-year life, project finance with a 80/20 debt/equity ratio, 9% interest on debt; includes 15% return on equity; 10-year depreciation.

(e) Calculated by multiplying capital $/kW by CCR and dividing by annual hours of operation.

(f) Conversion system only cost does not include capital and O&M costs associated with LFG collection system.

TABLE A.10 ESTIMATED COST OF ELECTRICITY (10 million Mg case) Municipal Bond Finance Case

Example: Landfill waste in place = 10 million metric tons

Cost Category	Units	IC Engine	Combustion Turbine	Combined Cycle CT	
POWER PROJECT COSTS					
Capital Costs (as–spent, 1996 online)					
Conversion system + collection system	$/kW	1,595	1,756	1,813	
Conversion system only	$/kW	1,109	1,249	1,458	
O&M Costs (1996)					
LFG collection system	c/kWh	0.4	0.4	0.4	(a)
Conversion system	c/kWh	1.8	1.3	1.5	(b)
Royalty Payments (1996)	c/kWh	0.5	0.5	0.5	(c)
FIRST YEAR COST OF ELECTRICITY (1996)					
Capital charge rate (muni bond finance)		0.111	0.111	0.111	(d)
Total Electricity Cost					
Levelized capacity price	c/kWh	2.5	2.8	2.9	(e)
1996 O&M price	c/kWh	2.2	1.7	1.9	
Royalty Payment	c/kWh	0.5	0.5	0.5	
Total 1996 cost of electricity	c/kWh	5.2	5.0	5.3	
Incremental Electricity Cost					(f)
Levelized capacity price	c/kWh	1.8	2.0	2.3	(e)
1996 O&M price	c/kWh	1.8	1.3	1.5	
Royalty Payment	c/kWh	0.5	0.5	0.5	
Total 1996 cost of electricity	c/kWh	4.1	3.8	4.3	

Notes:

(a) Based on EPA estimate for collection + flare systems (Exhibit 4–7), in $1996. [EPA]
(b) Based on O&M estimates published by Wolfe & Maxwell in "Commercial Landfill Recovery Operations– Technology and Economics," and in EPA Report to Congress (Exhibit 4–7).
(c) Royalty payments to the landfill owner are estimated to be 10% of revenues (4.9 c/kWh).
(d) Assumes tax–exempt municipal bond financing at 6.5%.
(e) Calculated by multiplying capital $/kW by CCR and dividing by annual hours of operation.
(f) Conversion system only cost does not include capital and O&M costs associated with LFG collection system.

TABLE A.11 COMPARISON OF PROJECT REVENUES & EXPENSES (1 st Year)

Example: Landfill waste in place = 5 million metric tons

	Units	IC Engine	Combustion Turbine	Combined Cycle CT
Revenues	c/kWh	4.9	4.9	4.9
PROJECT FINANCE CASE				
Expenses (including Owner's Return)				
Total	c/kWh	6.0	6.2	6.5
Incremental	c/kWh	4.6	4.7	5.3
Revenues Minus Expenses				
Total	c/kWh	(1.1)	(1.3)	(1.6)
Incremental	c/kWh	0.3	0.2	(0.4)
1996 Tax Credit	c/kWh	1.3	1.3	0.9
Estimated Surplus (Shortfall) Cash Flow After Taxes and Owner's Return				
Total Cost Basis	c/kWh	0.2	0.0	(0.7)
	$000	$69	$0	($332)
Incremental Cost Basis	c/kWh	1.6	1.5	0.5
	$000	$553	$497	$237
MUNICIPAL BOND FINANCE CASE				
Expenses (including financing costs)				
Total	c/kWh	5.0	5.1	5.3
Incremental	c/kWh	3.7	3.7	4.2
Revenues Minus Expenses				
Total	c/kWh	(0.1)	(0.2)	(0.4)
Incremental	c/kWh	1.2	1.2	0.7
1996 REPI Subsidy	c/kWh	0.0	0.0	0.0
Estimated Surplus (Shortfall) Cash Flow After Taxes and Financing Expenses				
Total Cost Basis	c/kWh	(0.1)	(0.2)	(0.4)
	$000	($35)	($66)	($190)
Incremental Cost Basis	c/kWh	1.2	1.2	0.7
	$000	$415	$398	$332

Notes:

See Tables A.12–A.14 for notes on calculations.

TABLE A.12 EXAMPLE POWER PROJECT REVENUES (1st Year)

Example: Landfill waste in place = 5 million metric tons

	Units	IC Engine	Combustion Turbine	Combined Cycle CT	
PROJECT OPERATING DATA					
Net sustainable landfill gas production	mcf/day	2,988	2,988	2,988	(a)
Gross electric output	kW	5,188	5,188	7,324	
Net electric output	kW	4,934	4,727	6,763	
Annual electricity generated	kWh	34,577,472	33,126,816	47,395,104	
Electricity used on-site	kWh	3,000,000	3,000,000	3,000,000	(b)
Net electricity sold to utility	kWh	31,577,472	30,126,816	44,395,104	
ANNUAL REVENUES					
Electricity Sales to Utility in 1st Year	$000	$1,522	$1,452	$2,140	(c)
Electricity Sales On-Site in 1st Year	$000	$177	$177	$177	(d)
Total Annual Revenues	$000	$1,699	$1,629	$2,317	
REVENUES ON PER kWh BASIS	c/kWh	4.9	4.9	4.9	(e)

Notes:

(a) Calculated using statistical model 4.2 in EPA Report to Congress. [EPA] The resulting methane production estimate is within the range predicted by the models presented in Part I.

(b) Assumed for example purposes.

(c) Product of utility sales kWh and assumed 1996 buyback electricity rate of 4.8 c/kWh.

(d) Product of on-site sales kWh and assumed 1996 retail electricity rate of 5.9 c/kWh.

(e) Total annual revenues divided by total kWh generated.

TABLE A.13 COMPARISON OF PROJECT REVENUES & EXPENSES (1 st Year) Project Finance Case

Example: Landfill waste in place = 5 million metric tons

	Units	IC Engine	Combustion Turbine	Combined Cycle CT	
REVENUES	c/kWh	4.9	4.9	4.9	(a)
EXPENSES (including Owner's Return)					(b)
Total	c/kWh	6.0	6.2	6.5	
Incremental	c/kWh	4.6	4.7	5.3	
REVENUES MINUS EXPENSES					
Total	c/kWh	(1.1)	(1.3)	(1.6)	
Incremental	c/kWh	0.3	0.2	(0.4)	
1996 TAX CREDIT					
	$/MMBtu	1.049	1.049	1.049	(c)
	c/kWh	1.3	1.3	0.9	(d)
ESTIMATED SURPLUS (SHORTFALL) CASH AFTER TAXES & OWNER'S RETURN					(e)
Total Cost Basis	c/kWh	0.2	0.0	(0.7)	
	$000	$69	$0	($332)	(f)
Incremental Cost Basis	c/kWh	1.6	1.5	0.5	
	$000	$553	$497	$237	

Notes:

(a) Calculated in Table A.12

(b) Calculated in Table A.6. Income taxes, property taxes, and owner's 15% return on equity are included in these expenses.

(c) Based on a tax credit of $0.979/MMBtu ($1994) escalated for 2 years @ 3.5%. [PUR]
If only 60% of tax credit is applied to project, credit drops by about 0.5 c/kWh, or about $173,000.

(d) Calculated by multiplying by an electric heat rate of 12.0 MMBtu/MWh for the IC and CT, and by 8.5 MMBtu/MWh for the combined cycle CT.

(e) Estimated Income is net of income taxes, property taxes, administrative expenses, and owner's 15% return on equity. A negative value indicates that first–year cash flow does not cover the owner's desired 15% return. It is assumed that the project/owner has sufficient tax liability to be able to take full advantage of the tax credit. In many cases, only about 60% of the tax credit can be used.

TABLE A.14 COMPARISON OF PROJECT REVENUES & EXPENSES (1 st Year) Municipal Bond Finance Case

Example: Landfill waste in place = 5 million metric tons

	Units	IC Engine	Combustion Turbine	Combined Cycle CT	
REVENUES	c/kWh	4.9	4.9	4.9	(a)
EXPENSES					(b)
Total	c/kWh	5.0	5.1	5.3	
Incremental	c/kWh	3.7	3.7	4.2	
REVENUES MINUS EXPENSES					
Total	c/kWh	(0.1)	(0.2)	(0.4)	
Incremental	c/kWh	1.2	1.2	0.7	
1996 REPI SUBSIDY	c/kWh	0.0	0.0	0.0	
ESTIMATED SURPLUS (SHORTFALL) CASH AFTER TAXES & FINANCING EXPENSES					
Total Cost Basis	c/kWh	(0.1)	(0.2)	(0.4)	(c)
	$000	($35)	($66)	($190)	
Incremental Cost Basis	c/kWh	1.2	1.2	0.7	
	$000	$415	$398	$332	

Notes:
(a) Calculated in Table A.12
(b) Expenses include the financing costs associated with issuing tax-exempt municipal bonds with a 6.5% interest rate (see Table A.7)
(c) Estimated Income is net of property taxes, administrative expenses, and bond financing expenses. A positive value indicates that first-year cash flow exceeds expenses, including the bond debt service expenses.

TABLE A.15 ESTIMATED MEDIUM-BTU PROJECT CAPITAL COSTS (1 million Mg case)

Example: Landfill waste in place = 1 million metric tons

Cost Category	Units	Baseload user (continuous)	Heat load user (seasonal)
OPERATING DATA			
Net sustainable landfill gas production	mcf/day	642	642 (a)
Net fuel output (MMBtu)	MMBtu/day	321	321 (b)
On-line date		6/96	6/96
Capacity factor (lifetime annual average)		90%	40% (c)
Annual full load operating hours	hours	7,884	3,504
Annual volume of gas sold	MMBtu	105,488	46,884
EQUIPMENT & INSTALLATION COSTS			
Gas Delivery System ($1994)			
Condensate removal/filtration	$000	8	8 (d)
Compressor/Blower station	$000	75	75 (e)
Pipeline interconnect	$000	350	350 (f)
Fuel burning equipment conversion	$000	150	150 (g)
Gas delivery system cost ($1994)		583	583
LFG collection system cost ($1994)	$000	628	628 (h)
Engineering ($1994)	$000	61	61 (i)
CAPITAL REQUIREMENT			
System cost ($1994)	$000	1,271	1,271
System cost ($1996)	$000	1,362	1,362
Soft costs($1996)			
Owners costs, escalation, interest		85	85 (j)
Contingency @5.0%		68	68
Total Soft Costs	$000	153	153
Total Capital Requirement (as-spent dollars, 1996 on-line date)	$000	1,515	1,515
Incremental Capital Requirement	$000	729	729 (k)

Notes:

(a) Based on landfill size of approximately 1 metric ton.[EPA]
(b) Assumes landfill gas has 500 Btu/cf, or 1 cf landfill gas = 0.5 cf methane.
(c) Assumes baseload user has a year-round need for gas, and heat load user only uses gas in the five winter months.
(d) Based on an estimate obtained from Perry Equipment for liquid and solid filtration system.
(e) Based on estimates published by Wolfe & Maxwell in "Commercial Landfill Recovery Operations – Technology and Economics", and in Augenstein and Pacey, "Landfill Gas Energy Utilization: Technology Options and Case Studies"
(f) Based on the cost of a one mile pipeline (pipeline costs can range from $250,000 to $500,000 per mile).
(g) Based on the cost of retrofitting one boiler.[PTI]
(h) Calculated based on EPA Exhibit 4-7; includes collection system + flare. [EPA]
(i) Calculated as 5% of conversion and collection costs.
(j) Included are owners' costs (legal, permitting, insurance, taxes), escalation during construction (6 months) and interest during construction.
(k) Excludes capital and soft costs associated with the LFG collection system.

TABLE A.16 ESTIMATED COST OF MEDIUM–BTU GAS (1M Mg case)

Example: Landfill waste in place = 1 million metric tons

Cost Category	Units	Baseload user (continuous)	Heat load user (seasonal)	
GAS PRODUCTION COSTS				
Capital Costs (as–spent, 1996 online)				(a)
Total capital requirement	$/MMBtu	14.36	32.31	
Incremental capital requirement	$/MMBtu	6.91	15.56	
O&M Costs (1996)				
LFG collection system	$/MMBtu	0.84	1.89	(b)
Gas delivery system	$/MMBtu	0.11	0.26	(c)
Tax Credit (1996)	$/MMBtu	1.049	1.049	(d, h)
FIRST YEAR COST OF GAS (1996)				
Capital charge rate		0.136	0.136	(e)
Total Gas Cost				
Levelized capacity price	$/MMBtu	1.95	4.39	(f)
1996 O&M price	$/MMBtu	0.95	2.14	
Total 1996 cost of gas	$/MMBtu	2.91	6.54	
Cost of gas including tax credit	$/MMBtu	1.86	5.49	
Incremental Gas Cost				(g)
Levelized capacity price	$/MMBtu	0.94	2.12	
1996 O&M price	$/MMBtu	0.11	0.26	
Total 1996 cost of gas	$/MMBtu	1.05	2.37	
Cost of gas including tax credit	$/MMBtu	0.01	1.32	

Notes:
(a) Assumes annual gas sales of 105,488 MMBtu to baseload user and 46,884 MMBtu to heat load user.
(b) Based on EPA estimate for collection + flare systems (Exhibit 4–7), escalated to $1996. [EPA]
(c) Based on pipeline delineation costs and minor filtration system maintenance costs. [Augenstein and Pacey]
(d) Based on a tax credit value of $0.979/MMBtu ($1994), escalated for 2 years. [PUR]
(e) Assumes: 20–year life, project finance with a 80/20 debt/equity ratio, 9% interest on debt; includes 15% return on equity; 10–year depreciation
(f) Calculated by multiplying capital $/MMBtu by CCR.
(g) Incremental Gas Cost does not include capital and O&M costs associated with LFG collection system.
(h) Assumes total value of tax credit goes to the project. In some cases, only a percentage of the tax credit value will be credited to the project due to transaction costs associated with transferring the credits to a third party. For example, 60% of the tax credit may be realized by the project developer; therefore, the value of the tax credit would only be (60% * $1.049), or $0.63/MMBtu.

TABLE A.17 ESTIMATED MEDIUM-BTU PROJECT CAPITAL COSTS (5 million Mg case)

Example: Landfill waste in place =		5 million metric tons		
Cost Category	**Units**	**Baseload user (continuous)**	**Heat load user (seasonal)**	
OPERATING DATA				
Net sustainable landfill gas production	mcf/day	2,988	2,988	(a)
Net fuel output (MMBtu)	MMBtu/day	1,494	1,494	(b)
On-line date		6/96	6/96	
Capacity factor (lifetime annual average)		90%	40%	(c)
Annual full load operating hours	hours	7,884	3,504	
Annual volume of gas sold	MMBtu	490,811	218,138	
EQUIPMENT & INSTALLATION COSTS				
Gas Delivery System ($1994)				
Condensate removal/filtration	$000	15	15	(d)
Compressor/Blower station	$000	100	100	(e)
Pipeline interconnect	$000	350	350	(f)
Fuel burning equipment conversion	$000	150	150	(g)
Gas delivery system cost ($1994)		615	615	
LFG collection system cost ($1994)	$000	2,098	2,098	(h)
Engineering ($1994)	$000	136	136	(i)
CAPITAL REQUIREMENT				
System cost ($1994)	$000	2,848	2,848	
System cost ($1996)	$000	3,051	3,051	
Soft costs($1996)				
Owners costs, escalation, interest		190	190	(j)
Contingency @5.0%		153	153	
Total Soft Costs	$000	343	343	
Total Capital Requirement (as-spent dollars, 1996 on-line date)	$000	3,394	3,394	
Incremental Capital Requirement	$000	769	769	(k)

Notes:

(a) Based on landfill size of approximately 5 metric tons.[EPA]
(b) Assumes landfill gas has 500 Btu/cf, or 1 cf landfill gas = 0.5 cf methane.
(c) Assumes baseload user has a year-round need for gas, and heat load user only uses gas in the five winter months.
(d) Based on an estimate obtained from Perry Equipment for liquid and solid filtration system.
(e) Based on estimates published by Wolfe & Maxwell in "Commercial Landfill Recovery Operations - Technology and Economics", and in Augenstein and Pacey, "Landfill Gas Energy Utilization: Technology Options and Case Studies"
(f) Based on the cost of a one mile pipeline (pipeline costs can range from $250,000 to $500,000 per mile).
(g) Based on the cost of retrofitting one boiler.[PTI]
(h) Calculated based on EPA Exhibit 4-7; includes collection system + flare. [EPA]
(i) Calculated as 5% of conversion and collection costs.
(j) Included are owners' costs (legal, permitting, insurance, taxes), escalation during construction (6 months) and interest during construction.
(k) Excludes capital and soft costs associated with the LFG collection system.

TABLE A.18 ESTIMATED COST OF MEDIUM-BTU GAS (5M Mg case)

Example: Landfill waste in place = 5 million metric tons

Cost Category	Units	Baseload user (continuous)	Heat load user (seasonal)
GAS PRODUCTION COSTS			
Capital Costs (as-spent, 1996 online)			(a)
Total capital requirement	$/MMBtu	6.92	15.56
Incremental capital requirement	$/MMBtu	1.57	3.53
O&M Costs (1996)			
LFG collection system	$/MMBtu	0.31	0.70 (b)
Gas delivery system	$/MMBtu	0.02	0.06 (c)
Tax Credit (1996)	$/MMBtu	1.049	1.049 (d, h)
FIRST YEAR COST OF GAS (1996)			
Capital charge rate		0.136	0.136 (e)
Total Gas Cost			
Levelized capacity price	$/MMBtu	0.94	2.12 (f)
1996 O&M price	$/MMBtu	0.34	0.75
Total 1996 cost of gas	$/MMBtu	1.28	2.87
Cost of gas including tax credit	$/MMBtu	0.23	1.82
Incremental Gas Cost			(g)
Levelized capacity price	$/MMBtu	0.21	0.48
1996 O&M price	$/MMBtu	0.02	0.06
Total 1996 cost of gas	$/MMBtu	0.24	0.53
Cost of gas including tax credit	$/MMBtu	(0.81)	(0.51)

Notes:

(a) Assumes annual gas sales to baseload user of 490,811 MMBtu and sales of 218,138 MMBtu to heat load user.
(b) Based on EPA estimate for collection + flare systems (Exhibit 4-7), escalated to $1996. [EPA]
(c) Based on pipeline delineation costs and minor filtration system maintenance costs. [Augenstein and Pacey]
(d) Based on a tax credit value of $0.979/MMBtu ($1994), escalated for 2 years. [PUR]
(e) Assumes: 20-year life, project finance with a 80/20 debt/equity ratio, 9% interest on debt; includes 15% return on equity; 10-year depreciation
(f) Calculated by multiplying capital $/MMBtu by CCR.
(g) Incremental Gas Cost does not include capital and O&M costs associated with LFG collection system.
(h) Assumes total value of the tax credit goes to the project. In some cases, only a percentage of the tax credit value will be credited to the project due to transaction costs associated with transferring the credits to a third party. For example, 60% of the credit may be realized by the project developer; therefore, the value of the tax credit would only be (60% * $1.049), or $0.63/MMBtu.

TABLE A.19 ESTIMATED MEDIUM–BTU PROJECT CAPITAL COSTS (10 million Mg case)

Example: Landfill waste in place = 10 million metric tons

Cost Category	Units	Baseload user (continuous)	Heat load user (seasonal)	
OPERATING DATA				
Net sustainable landfill gas production	mcf/day	5,266	5,266	(a)
Net fuel output (MMBtu)	MMBtu/day	2,633	2,633	(b)
On–line date		6/96	6/96	
Capacity factor (lifetime annual average)		90%	40%	(c)
Annual full load operating hours	hours	7,884	3,504	
Annual volume of gas sold	MMBtu	864,917	384,408	
EQUIPMENT & INSTALLATION COSTS				
Gas Delivery System ($1994)				
Condensate removal/filtration	$000	25	25	(d)
Compressor/Blower station	$000	200	200	(e)
Pipeline interconnect	$000	350	350	(f)
Fuel burning equipment conversion	$000	150	150	(g)
Gas delivery system cost ($1994)		725	725	
LFG collection system cost ($1994)	$000	3,599	3,599	(h)
Engineering ($1994)	$000	216	216	(i)
CAPITAL REQUIREMENT				
System cost ($1994)	$000	4,540	4,540	
System cost ($1996)	$000	4,863	4,863	
Soft costs($1996)				
Owners costs, escalation, interest		303	303	(j)
Contingency @5.0%		243	243	
Total Soft Costs	$000	546	546	
Total Capital Requirement (as–spent dollars, 1996 on–line date)	$000	5,410	5,410	
Incremental Capital Requirement	$000	907	907	(k)

Notes:

(a) Based on landfill size of approximately 10 metric tons.[EPA]
(b) Assumes landfill gas has 500 Btu/cf, or 1 cf landfill gas = 0.5 cf methane.
(c) Assumes baseload user has a year–round need for gas, and heat load user only uses gas in the five winter months.
(d) Based on an estimate obtained from Perry Equipment for liquid and solid filtration system.
(e) Based on estimates published by Wolfe & Maxwell in "Commercial Landfill Recovery Operations – Technology and Economics", and in Augenstein and Pacey, "Landfill Gas Energy Utilization: Technology Options and Case Studies"
(f) Based on the cost of a one mile pipeline (pipeline costs can range from $250,000 to $500,000 per mile).
(g) Based on the cost of retrofitting one boiler.[PTI]
(h) Calculated based on EPA Exhibit 4–7; includes collection system + flare. [EPA]
(i) Calculated as 5% of conversion and collection costs.
(j) Included are owners' costs (legal, permitting, insurance, taxes), escalation during construction (6 months) and interest during construction.
(k) Excludes capital and soft costs associated with the LFG collection system.

TABLE A.20 ESTIMATED COST OF MEDIUM–BTU GAS (10M Mg case)

Example: Landfill waste in place = 10 million metric tons

Cost Category	Units	Baseload user (continuous)	Heat load user (seasonal)	
GAS PRODUCTION COSTS				
Capital Costs (as–spent, 1996 online)				(a)
Total capital requirement	$/MMBtu	6.25	14.07	
Incremental capital requirement	$/MMBtu	1.05	2.36	
O&M Costs (1996)				
LFG collection system	$/MMBtu	0.25	0.57	(b)
Gas delivery system	$/MMBtu	0.01	0.03	(c)
Tax Credit (1996)	$/MMBtu	1.049	1.049	(d, h)
FIRST YEAR COST OF GAS (1996)				
Capital charge rate		0.136	0.136	(e)
Total Gas Cost				
Levelized capacity price	$/MMBtu	0.85	1.91	(f)
1996 O&M price	$/MMBtu	0.27	0.60	
Total 1996 cost of gas	$/MMBtu	1.12	2.51	
Cost of gas including tax credit	$/MMBtu	0.07	1.46	
Incremental Gas Cost				(g)
Levelized capacity price	$/MMBtu	0.14	0.32	
1996 O&M price	$/MMBtu	0.01	0.03	
Total 1996 cost of gas	$/MMBtu	0.16	0.35	
Cost of gas including tax credit	$/MMBtu	(0.89)	(0.70)	

Notes:

(a) Assumes annual gas sales to baseload user of 864,917 MMBtu and sales of 384,408 MMBtu to heat load user.
(b) Based on EPA estimate for collection + flare systems (Exhibit 4–7), escalated to $1996. [EPA]
(c) Based on pipeline delineation costs and minor filtration system maintenance costs. [Augenstein and Pacey]
(d) Based on a tax credit value of $0.979/MMBtu ($1994), escalated for 2 years. [PUR]
(e) Assumes: 20–year life, project finance with a 80/20 debt/equity ratio, 9% interest on debt; includes 15% return on equity; 10–year depreciation
(f) Calculated by multiplying capital $/MMBtu by CCR.
(g) Incremental Gas Cost does not include capital and O&M costs associated with LFG collection system.
(h) Assumes total value of tax credit goes to the project. In some cases, only a percentage of the tax credit value will be credited to the project due to transaction costs associated with transferring the credits to a third party. For example, 60% of the credit may be realized by the project developer; therefore, the value of the tax credit would only be (60% * $1.049), or $0.63/MMBtu.

APPENDIX B

LIST OF U.S. EPA OFFICES

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U.S. Environmental Protection Agency Offices

EPA Region	EPA Address	States Included in Region	Regional Contact	Phone	Fax
	Landfill Methane Program 401 M St., SW, 6202J Washington, DC 20460	All		202-233-9042	
1	John F.Kennedy Federal Bldg. One Congress Street Boston, MA 02203	CT, ME, MA, NH, RI, VT	Jeanne Cosgrove	617-565-9451	617-565-4940
2	Federal Office Bldg. 26 Federal Plaza New York, NY 10278	NJ, NY, Puerto Rico, Virgin Islands	Christine DeRosa	212-637-4022	212-637-3998
3	Curtis Building Sixth and Walnut Streets Philadelphia, PA 19106	DE, DC, MD, PA, VA, WV	Jim Topsale	215-566-2190	215-566-2124
4	345 Courtland, NE Atlanta, GA 30308	AL, FL, GA, MS, KY, NC, SC, TN	Scott Davis	404-347-5014 Ext. 4144	404-347-3059
5	230 South Dearborn St. Chicago, IL 60604	IL, MN, MI, OH, IN, WI	Charles Hatten	312-886-6031	312-886-5824
6	First International Bldg. 1202 Elm Street Dallas, TX 75270	AR, LA, NM, OK, TX	Mick Cote	214-665-7219	214-665-2164
7	324 E. Eleventh Street Kansas City, MO 64106	IA, KS, MI, NE	Ward Burns	913-551-7960	913-551-7065

EPA Region	EPA Address	States Included in Region	Regional Contact	Phone	Fax
8	1860 Lincoln Street Denver, CO 80295	CO, MN, ND, SD, UT, WY	John Dale	303-312-6934	303-312-6064
9	215 Freemont Street San Francisco, CA 94105	AZ, CA, HI, NV, Guam, American Samoa	Patricia Bowlin	415-744-1188	415-744-1076
10	1200 Sixth Avenue Seattle, WA 98101	WA, OR, ID, AK	John Keenan	206-553-1817	206-553-0110

APPENDIX C

EXECUTIVE SUMMARY OF A POWER PURCHASE AGREEMENT

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EXECUTIVE SUMMARY OF PURCHASED POWER AGREEMENT

Supplier Name

This Executive Summary describes the principal terms and conditions of an agreement (the "Agreement") between Duke Power Company ("Duke") and the owner/operator ("Supplier") of an electric generating facility which is a qualified facility ("QF") under the Public Utilities Regulatory Policies Act of 1978 ("PURPA"). In the event of an inconsistency or conflict between the Agreement and this Executive Summary the terms of the Agreement shall apply.

ARTICLE 1 (Service Requirements) sets forth basic information about Supplier's facility (the "Facility") including, among other things, its nameplate capacity, location of the delivery point where Supplier will deliver energy to Duke, and the Supplier's "Capacity Commitment" (the average capacity in kilowatts Supplier commits to deliver to Duke during On-Peak Hours). Articles 1.6 and 1.7 set forth metering and fuel cost information requirements. Article 1.9 states that back-up and maintenance power for the Facility's auxiliary electrical requirements shall be purchased from Duke pursuant to a separate electric service agreement on an appropriate rate schedule.

ARTICLE 2 (Service Regulations and Regulatory Approval) states that the Agreement is contingent upon the Supplier obtaining and maintaining approval from all applicable regulatory bodies. Article 2.2 states that the provisions of the Agreement are subject to review by the North Carolina Utilities Commission (the "Commission"), and Article 2.3 provides that the sale, delivery, receipt and use of electric power under the Agreement is governed by Duke's Service Regulations as filed with the Commission, and that changes to said regulations upon order of the Commission, which changes are in conflict with the provisions of this Agreement, shall control over such provisions. However, Article 2.4 states that to the extent this Agreement is explicity approved by an order of the Commission, Article 2.2 shall not apply, and the Agreement shall control over any changes to the Service Regulations except those which relate to extra facilities and metering. Article 2.5 states that whether or not the Agreement is explicity approved by the Commission, it is thereafter subject to review in a general rate case or by complaint proceeding.

According to ARTICLE 3 (Term), the term of the Agreement begins on the date of execution and shall continue for ______ years from the Commercial Operations Date, which is defined in Article 3.4 as the date of the first regular meter reading following receipt by Duke of written notice from the Supplier declaring the Facility to be in Commercial Operation, after the Facility has passed acceptance testing. The Anticipated Commercial Operations Date is _______________, 199__, but Supplier may revise the Anticipated Commercial Operations Date one time during the first six months following execution of the Agreement, to a date not later than twelve months after the originally specified date.

Article 3.2 provides that the Supplier shall notify Duke of the date of the commencement of construction of the Facility, commencement of construction being defined therein.

Article 3.3 provides that the Initial Delivery Date shall be the first date upon which energy is generated by the Facility and delivered to and metered by Duke. The Anticipated Initial Delivery Date is _______________. The Supplier may change the Anticipated Initial Delivery Date on written notice to Duke at least one year prior to the revised date, but in no event may the Initial Delivery Date be earlier than ____________________.

Article 3.5 sets forth a procedure to determine the disposition of power produced by the plant after the expiration of this Agreement. Between 45 and 60 months prior to the expiration of this Agreement, Supplier must notify Duke as to whether it wishes to continue to generate electricity at the Facility. If it does, Duke must then, within six months of Supplier's notice, respond by notifying Supplier as to whether Duke wishes to continue to purchase energy and capacity. If Duke does wish to continue such purchases, the parties will then enter into good-faith negotiations to conclude a new purchased power agreement. The rates for the new agreement will be determined based upon Duke's then-current projections of avoided capacity and energy costs and other relevant factors. If Duke notifies Supplier that it does not wish to continue to purchase energy and capacity, or if the parties cannot reach a new agreement, then they are to negotiate the disposition of power to be generated at the Facility, provided that Duke is not to be obligated to transmit power from the Facility directly to any ultimate consumers of electricity.

ARTICLE 4 (Rate Schedule) provides that energy and capacity payments to the Supplier will be determined using the rates or rate formulas set forth in Appendix A, applying the energy credit rates to the KWH delivered to Duke during the On-Peak Hours and Off-Peak Hours (as defined therein) of each month, and applying the capacity credit rates to the KWH delivered to Duke during the On-Peak Hours of each month, up to a maximum of 110 percent of the then-applicable Capacity Commitment. Article 4.6 sets forth a mechanism for adjusting the energy in the event the average monthly power factor is less than 90 percent or greater than 97 percent.

Article 4.7 provides that payments to be made to the Supplier are conditioned on recovery by Duke of all of said payments from its customers. If Duke is denied such recovery, Duke may reduce payments to Supplier to the highest level allowed by the Commission or other regulatory body. If Duke initially recovers payments, but recovery is subsequently disallowed and charged back to Duke, Duke may offset subsequent payments due from Duke to Supplier, or may require repayment by Supplier.

ARTICLE 5 (Capacity Commitment) states that Supplier shall operate its generating facilities so as to meet its Capacity Commitment as designated in Article 1.5(b) in each On-Peak Month. Article 5.1(a)-(d) sets forth the definitions of "Capacity Commitment"; "Average On-Peak Capacity"; "Monthly Capacity Ratio" and "Annual Capacity Ratio" and the methodologies for calculating them. Article 5.1(e) states that reductions in capacity resulting from Service Interruptions (as defined in Article 8), changes in steam sales requirements or for reasons other than Force Majeure that occur during the On-Peak Hours of the On-Peak Months are not excluded from the calculations of the Average On-Peak Capacity and the Capacity Ratios. Article 5.1(f) sets forth the circumstances under which On-Peak Months during which performance has been affected by conditions or events of Force Majeure shall be excluded from or included in the calculation of the Annual Capacity Ratio.

Article 5.2 states that when the Annual Capacity Ratio is less than 90 percent for two consecutive months, the Capacity Commitment will automatically be reduced. The revised Capacity Commitment is calculated by multiplying the previous Capacity Commitment by the Annual Capacity Ratio existing at the end of the two-month period. In the event of an automatic Capacity Commitment reduction, pursuant to Article 5.2(a), or an agreed-upon Capacity Commitment reduction pursuant to Article 5.2(b), the costs and damages provisions of Paragraph 11.1 shall apply, according to Article 5.4.

ARTICLE 6 (Interconnection Facilities) states that Duke will furnish, own and maintain appropriate interconnection facilities in order to serve the Supplier. Supplier shall, upon completion of installation of the Interconnection Facilities, pay a monthly charge totaling, as a preliminary estimate, $______________, which is 1.7 percent of the installed cost. The final costs and charges shall be calculated no earlier than 12 months prior to the installation of the Interconnection Facilities. Duke reserves the right to install additional facilities, and to adjust the Interconnection Facilities Charge for such additional facilities or to reflect Commission-approved changes in the Extra Facilities provisions of Duke's Service Regulations.

ARTICLE 7 (Payments) sets forth billing and payment procedures. Duke reserves the right to set off any amounts due to it from Supplier against any amounts due from Duke to Supplier.

ARTICLE 8 (Service Interruptions) states that, while the parties shall use reasonable diligence to provide satisfactory service, they do not guarantee continuous service. Article 8.2 lists conditions or events which are defined as "Service Interruptions." Pursuant to Article 8.3, neither party shall be liable for any loss or damage resulting from Service Interruptions, except that Supplier shall be liable to Duke for costs and damages as set forth in Article 11.1 if the occurrence of Service Interruptions results in a capacity reduction.

ARTICLE 9 (Force Majeure) defines certain circumstances which are "beyond the reasonable control" of the parties as "conditions or events of Force Majeure", and also lists certain events and circumstances which are excluded from that definition. Pursuant to Article 9.3, if certain conditions are met, then the parties are not responsible for any delay or failure of performance due solely to force majeure (except for the requirement for Supplier to begin commercial operation as set forth in Article 3.4). However, notwithstanding Article 9.3, Article 9.4 states that such failures of performance may be excused by force majeure for periods of no longer than one year and not beyond the term of the Agreement. Thus, delays or failures of performance, even if excused by force majeure, become defaults one year from the date that the affected party notifies the other party of the condition or event of Force Majeure. At such time, the other party may terminate the Agreement or may, in its sole discretion, extend the period for which the delay or failure in performance is excused. If, under such circumstances, Duke does not terminate the Agreement, and the condition or event of Force Majeure results in a capacity reduction, then the provisions of Article 5.1(f), which relate to the inclusion or exclusion of months for calculation of the Annual Capacity Ratio, apply. Pursuant to Article 9.5, if the parties anticipate that any condition or event of Force Majeure will cause a capacity reduction, the parties may thereafter agree to reduce the Capacity Commitment, pursuant to Article 5.2(b), with the Supplier paying costs and damages to Duke for such reduction pursuant to Article 11.1.

ARTICLE 10 (Default) sets forth procedures to be followed in the event of default. Unless the default arises out of a condition or event of Force Majeure, in which event the provisions of Article 9 shall apply, the defaulting party is given 60 days to cure the default (except that if it cannot be cured within 60 days with the exercise of due diligence, the defaulting party may submit a plan for the other party's approval which will correct the default within a reasonable period of time not to exceed six months). If the defaulting party fails to submit such a plan, or if the other party declines to approve it, or if the defaulting party fails to cure the default in conformance with the plan, then the other party may exercise its rights and remedies as set forth in Article 10. Article 10.2 lists a variety of specific circumstances and events which constitute a default by Supplier.

ARTICLE 11 (Costs and Damages) sets forth certain damages which Supplier may be required to pay to Duke upon occurrence of: each capacity reduction (including agreed upon capacity reductions pursuant to Articles 5.2(b) or 9.5); termination by Duke due to Supplier's default; default by Supplier pursuant to Article 10 which does not result in a termination or reduction in capacity; or termination pursuant to Article 9.4. The costs and damages include: unpaid charges due to Duke including Interconnection Facilities charges; costs associated with the removal of Interconnection Facilities; loss due to early retirement of the Interconnection Facilities; and, in the event of a termination or capacity reduction, liquidated damages to compensate Duke for the detrimental effect on Duke's cost of power. The liquidated damages shall be calculated pursuant to the formulas in Appendix B. Also, in the event of a default by Supplier which does not result in a termination or capacity reduction, any actual damages incurred by Duke shall be paid by Supplier.

ARTICLE 12 (Operation of the Generating Facilities) sets forth certain responsibilities of the Supplier in its operation of the Facility. These include: Supplier is responsible for providing devices on its equipment to assure that there is no disturbance to Duke's facilities or other customers, and to protect Supplier's equipment from damage; Supplier agrees to operate and maintain the Facility "in accordance with applicable electric utility industry standards and good engineering practices" and in a prudent manner which will produce the maximum electric energy output consistent with the Agreement's dispatch and Capacity Commitment provisions; and Supplier shall coordinate its schedule for routine maintenance so that scheduled outages and capacity reductions occur during Off-Peak Hours or Off-Peak Months, with scheduled maintenance resulting in outages or capacity reductions restricted to 45 days per year. Article 12.3 includes a chart which sets forth the required *minimum* advance notice to Duke of scheduled outages according to the duration of the outage. Article 12.4 states that in the event of an emergency condition on Duke's system, Supplier shall increase or decrease the output of the Facility upon Duke's request, within the design limits of the facility.

ARTICLE 13 (Liability and Indemnity) sets forth liability and indemnity provisions for the Agreement. The indemnifying party agrees to be responsible for damages to persons or property arising out of the indemnifying party's negligent or tortious acts, errors or omissions, whether such persons or property are affiliated with the indemnifying party, the other party or third parties. Indirect and consequential damages are excluded.

ARTICLE 14 (Security) sets forth Supplier's obligation to provide security under the Purchased Power Agreement for its performance, including its obligation to pay costs and damages pursuant to Article 11.1. Such Security must be in place within 60 days after the Agreement is approved or accepted by filing by the Commission, and shall be maintained through the term of the Agreement. Article 14.2 sets forth the formula which shall be used annually to determine the amount of security required, and provides that the Security may be reduced by 50 percent from the commencement of construction of the Facility until 15 days prior to the Commercial Operations Date. Article 14.3 specifies the form of security, which may be an irrevocable standby letter of credit, a performance bond or cash. Articles 14.4 and 14.5 contain provisions designed to ensure that the security remains in force continuously during the term of the Agreement.

ARTICLE 15 (Communications) sets forth procedures for communications and notices between the parties.

ARTICLE 16 (Assignability) requires the Supplier to advise Duke and the Commission of any plans to sell, transfer or assign the Facility, and restricts the rights of the parties to assign or subcontract the Agreement and its rights and duties. In most cases consent of the other party (which shall not be unreasonably withheld) is required prior to assignment or subcontracting. However, such consent is not required prior to an assignment by Duke to a parent, subsidiary or affiliated corporation, or by Supplier to a trustee or mortgagee pursuant to a financing agreement. In the case of any assignment, with or without prior consent, prior notice must be given to the other party, the assignee shall expressly assume the assignor's obligations (but no such assignment shall relieve the assignor of its obligations to perform in the event the assignee fails to perform), the assignment shall not impair any security given by Seller, and the contemplated assignee must obtain any necessary regulatory approvals including that of the Commission.

ARTICLE 17 (Miscellaneous) contains various contractual provisions. Supplier should review all of the provisions of Article 17.

APPENDICES:

APPENDIX A sets forth the rate or rate formulas.

APPENDIX B sets forth the formula for calculating liquidated damages.

APPENDIX C sets forth the estimated Interconnection Facilities charges.

APPENDIX D sets forth the formulas for calculating the power factor adjustment.

APPENDIX E includes Duke's Service Regulations in effect as of the date of execution of this Agreement.

APPENDIX D

SAMPLE REQUEST FOR PROPOSALS FOR LANDFILL GAS ENERGY PROJECT DEVELOPER

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Department of Solid Waste

REQUEST FOR PROPOSALS - LANDFILL GAS
15 July 94

The City is soliciting proposals from environmental or energy management organizations, user industries, turnkey system providers and environmental engineering firms for the beneficial use of landfill gas (LFG).

BACKGROUND

The City owns and operates a 200+ acre Solid Waste Management Center (SWMC) which is managed by the Solid Waste Department. The SWMC contains a recently closed landfill having a footprint of approximately 52 acres. That landfill, the focus of this RFP, was originally placed on glacial till and is now capped with materials in compliance with New York's Part 360 regulations.

The cap design includes a membrane and a series of vent structures. Underneath the membrane is a permeable layer of natural materials which also contains a series of collection pipes, all linked to two header pipes emerging from under the cap at opposite points along the landfill's perimeter. A gravity leachate interception system has also been constructed beneath the perimeter of the landfill, leading to a single discharge point wherein any flowing condensate and residual LFG may be intercepted.

The design principle was to allow for conversion from a passive to an active LFG system by sealing the vents and activating a pumping system at one or both of the headers.

Initial measurements suggest natural production of approximately 975,000 cubic feet of LFG each day. This was based on a composite of low pressure measurements at 53 vent stacks. There are six other emission points were not measured at the time. Qualitative data is attached, as measured on a Landtec Gem 500. Data and observations suggest that the entire regime is currently sensitive to ambient air pressure differentials induced by wind.

Other features within the SWMC include:

1) a separate new active landfill with a present 10 acre footprint

and a loading rate of approximately 34,000 tons per year, which began operations in Sept. '92,

2) a 4,000 s.f. maintenance building for department vehicles and equipment,

3) overhead electric transmission lines with various voltages,

4) underground natural gas (high pressure) pipelines,

5) a 650,000 gallon glass lined steel open top storage tank for leachate (emergency use only), and

6) an improved roadway system between features.

Planned or contemplated improvements within or immediately adjacent to the SWMC include:

a) a compost processing area for vegetative waste materials,

b) artificial wetlands for partial or full treatment of landfill leachate,

c) a major structure for processing recyclable materials, possibly linked with a privately operated manufacturing enterprise utilizing recycled materials as feedstock(s), and

d) a new central garage facility within the SWMC for City owned vehicles.

Adjacent to the SWMC is an industrial park, including a major facility for the manufacture of air conditioning equipment and several other manufactures. Approximately 50 acres remain available for development. The Park is entirely within a NYS Economic Development Zone ("EDZ").

Nearby is a wastewater treatment plant which is owned and operated by the City (land linked). It contains a sludge incinerator and numerous pumps.

The City's Utilities Department operates two hydroelectric generation plants (combined 1.2 MW) and has plans for at least one additional plant in the near future.

Major intercepting sewer system components are located within contiguous City-owned rights of way.

RESPONDENTS SHOULD TAKE INTO CONSIDERATION THAT IT IS THE CITY'S INTENT TO MAXIMIZE THE USE AND BENEFIT OF ALL AVAILABLE CITY RESOURCES AND INFRASTRUCTURE IN THE MOST COST-EFFECTIVE MANNER POSSIBLE.

REQUEST FOR PROPOSALS

The City views the LFG at the SWMC as an untapped resource whose collection system is installed. Primary interest is in LFG utilization with maximum benefit to the City as a return on the substantial investment made in the SWMC to data. This benefit may take the form of one or more of the following:

- simplified sale of the LFG "as is, where is",
- royalties based on LFG utilization by others,
- direct earnings after additional investment in enterprise by the City, and
- realized savings from avoided costs (to obtain other conventional fuels).

The City and/or its agents are willing to consider conventional contracts, "Performance Based" contracts, partnerships, joint ventures, management agreements, and other appropriate mechanisms respondents may propose.

REQUIRED COMPONENTS OF RESPONSES

1) A basic component of all responsive proposals must be the provision of sufficient professional engineering services to accurately and responsibly portray technical issues regarding the complex medium of landfill gas, and do so gracefully within the arena of environmental regulations as they are administered by the New York State DEC and the federal EPA. As a minimum, flaring or any alternative backup methodology is to be included in order to avoid reversion to a passive venting system except under significant emergency conditions. A

permanent and adequate LFG monitoring system is to be included in this component.

2) Additional components should address one or more means by which the energy represented in combustible gas can be harnessed, either by direct combustion of LFG or subsequent to refinement. Proposals incorporating utilization of byproduct gas (from refinement) are encouraged.

3) Since LFG production is presumed to remain relatively constant throughout the year, additional components should also address levelizing consumption or incorporating storage if necessary or beneficial.

4) Any necessary design or structural adjustments to the existing LFG collection system must be clearly stated.

5) Proposals incorporating electrical energy distribution beyond a local regulated system should also address matters relating to wheeling.

6) Respondents are encouraged to incorporated design and operations procedures adjustments for the currently operating landfill (also within the SWMC) in order to capitalize on increasing amounts of LFG being generated therein.

7) Proposals should clearly state the nature of the initial working relationship between the City and the proposer. It should also state any proprietary interest the proposer has in other proposed or operating LFG utilization systems.

8) If proposers include subordinated or collaborative roles by other organizations, those roles should be clearly stated.

ILLUSTRATIONS OF POTENTIAL RELATIONSHIPS WITH AUBURN

1) As consultant, providing professional engineering or management services - with the City fully responsible for fiscal implementation with or without contracted operations services.

2) As turnkey provider of a designed, permitted and constructed facility with all user/sales agreements in place.

3) As wellhead purchaser of LFG with or without lease/purchase of real estate within the SWMC and/or industrial park.

4) As equity partner in the development and operation of a LFG system and/or related enterprise, utilizing subordinated engineering services.

5) As long term contractor for inclusion of LFG as part of more extensive solid waste management services.

6) As federal/state research and development agency, sharing an equity role.

Proposers are invited to counsel the City regarding the technical and business merits of as many LFG utilization options as appear to be practical for the City to independently or mutually pursue toward the goals of increasing revenue and/or avoiding costs: and, leveraging this resource as a development incentive for new enterprises. They may also be direct action proposals.

It is not the intent of this RFP to emphasize the need for further detailed quantitative or qualitative analysis of LFG presently generated within the SWMC.

Most aspects of proposals are considered to be public domain. Those aspects considered to be proprietary should be identified and bound separately, thereupon they will honored as such. Until such time as formal negotiations begin with a selected proposer, it is suggested that cost and/or investment information be stated in ranges. Cost and/or investment information will be kept confidential during negotiations, but final agreements will be public domain.

PROPOSAL TIMETABLE

The City is actively pursuing construction projects which may benefit from the use of LFG. It is also mindful of the value lost while passive ventilation of LFG takes place. Due to the potential complexity of different proposals, only a target date of 1 Aug 94 has been established. Following an initial response of interest (together with any generic qualification information), the City will schedule a preproposal conference, during which time all available information regarding the SWMC, the neighboring industrial park, and potentially related City projects can be reviewed. Field orientation will also be provided. Potential proposers will be canvassed regarding preparation time before a final proposal date is established.

TENTATIVE SCHEDULE

RFP available/mailed to prospective respondents	15 July 94
Initial expression of interest to City by	27 July 94
Preproposal conference, incl. site visit	wk of 1 Aug 94
Repeat preproposal conf., as needed	3rd wk of August
Proposal Submission Date:	15 Sept 94

CITY'S PROPOSAL EVALUATION TEAM

The team will consist of the City Manager, the Utilities Director, the Solid Waste Director, the Corporation Counsel, and a member of the City Council. The same team will later guide formal agreements to conclusion.

PROPOSAL EVALUATION CRITERIA

Proposals will be evaluated in terms of:

- comprehensiveness 20%
- creativity 10%
- earnings potential for City 50%
- recognition of solid waste priorities 10%
- recognition of environmental concerns 10%

BRIEF SOLID WASTE HISTORY IN AUBURN

Since it's founding over 200 years ago, the City gradually became involved in waste disposal, first as provider of various dumps, then as collector. Burning dumps finally became a thing of the past in the 1950's with the most recent one being along the edge of North Division St. - at the entrance to the SWMC.

Collection services for garbage and trash became more precise as interest grew in recycling. At about the same time the State regulations were strengthening with regard to land disposal.

Disposal operations continued on the large site at the extreme Northwest corner of the City, but now as a sanitary landfill. Burning practices stopped. A new section of the site was utilized, but liner systems had not yet entered the regulatory regime. Wastes came in from many areas of Cayuga County, and even portions of neighboring Onondaga County.

Between the 1950's and 1980's many on Auburn's older structures were demolished as the economic base shifted away from a wide variety of manufacturing, which had origins along the waterway running through the center of the City. Remains of several factories and related structures ended up in the (common) landfill, which was extended laterally over the relatively tightly compacted natural ground. The entire site has a complex geologic history due in part to glacial movements.

As solid waste matters came more into focus, New York's plans and regulations evolved into some of the most sophisticated in the nation. It became a common objective to switch away from unlined landfills to lined ones.

Auburn's 50 acre+ landfill was one slated for closure. The City was destined by plan to continue providing and disposal capacity for the entire county. A replacement landfill was built on lands partly within the City and partly on lands acquired by the City and later annexed.

New York's regulatory standards for closure of all landfills continued to strengthen, and Auburn suddenly faced a multi million dollar closure investment toward the end of the landfill's permitted life. To meet those costs, the City worked out a Consent Order with the NYSDEC to continue operating in the then existing landfill, (known as Landfill No. 1), while constructing a new lined Landfill No. 2. During this window of opportunity for raising closure capital, the City allowed importation of large quantities of waste from distant sources, which was allowable since no lateral expansion of the footprint was necessary.

Hence, during the final two years of its operation (ending 15 Sept 92), Landfill No. 1 commonly received up to 2,500 tons of waste per day, up from the routine amount by a factor of at least 10. All of those wastes were added to the relatively low and spread out landfill as it had evolved prior to importation. For that short period of time, the operation was more similar to those of larger metropolitan systems.

Landfill's No. 1's closure included some regarding, the placement of a more rational means to intercept remaining leachate, and a circumfrential roadway. Capping was begun on a North Slope even while filling continued to the South. The first detailed engineering work was done by C&S Engineers, and construction was by the Haseley Trucking Co.

After Landfill No. 2 opened, waste importation ceased. Tonnage abruptly returned to more "normal" levels. At that time, the South Slope closure work was begun with Steams & Whaler providing engineering services and the Tug Hill Construction company doing the improvements. With winter shutdowns, it took just under two years to complete closure construction at an overall cost approaching $10 million. Coordination of side by side engineering and construction was provided by the Department, with a welcomed role played by the Regional Office of the NYSDEC.

The City has developed an entrepreneurial approach to fiscal integrity. The SWMC will continue to play a strong role in providing revenue to the general fund. This will likely take several forms, as more and more management strategies are developed particular components of the solid waste stream. The City considers it prudent to only landfill those materials which cannot be managed within higher priority methodologies.

The benefit, as such, from large scale recent waste intake is now the natural production of an energy source. It is the City's objective to harness that energy to the benefit of the city as a whole, and/or the direct benefit to higher priority management of those wastes which do not <u>have</u> to be landfilled.

In its present configuration, the SWMC will continue to meet the needs of the Local Planning Unit (Cayuga County) for decades to come.

APPENDIX E

EPA MEMORANDUM ON POLLUTION CONTROL PROJECTS AND NEW SOURCE REVIEW (NSR) APPLICABILITY

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

OFFICE OF
AIR QUALITY PLANNING
AND STANDARDS

JUL 1 1994

MEMORANDUM

SUBJECT: Pollution Control Projects and New Source Review (NSR) Applicability

FROM: John S. Seitz, Director
Office of Air Quality Planning and Standards (MD-10)

TO: Director, Air, Pesticides and Toxics Management Division, Regions I and IV
Director, Air and Waste Management Division, Region II
Director, Air, Radiation and Toxics Division, Region III
Director, Air and Radiation Division, Region V
Director, Air, Pesticides and Toxics Division, Region VI
Director, Air and Toxics Division, Regions VII, VIII, IX and X

This memorandum and attachment address issues involving the Environmental Protection Agency's (EPA's) NSR rules and guidance concerning the exclusion from major NSR of pollution control projects at existing sources. The attachment provides a full discussion of the issues and this policy, including illustrative examples.

For several years, EPA has had a policy of excluding certain pollution control projects from the NSR requirements of parts C and D of title I of the Clean Air Act (Act) on a case-by-case basis. In 1992, EPA adopted an explicit pollution control project exclusion for electric utility generating units [see 57 FR 32314 (the "WEPCO rule" or the "WEPCO rulemaking")]. At the time, EPA indicated that it would, in a subsequent rulemaking, consider adopting a formal pollution control project exclusion for other source categories [see 57 FR 32332]. In the interim, EPA stated that individual pollution control projects involving source categories other than utilities could continue to be excluded from NSR by permitting authorities on a case-by-case basis [see 57 FR at 32320]. At this time, EPA expects to complete a rulemaking on a pollution control project exclusion for other source categories in early 1996. This memorandum and attachment provide interim guidance for permitting authorities on the approvability of these projects pending EPA's final action on a formal regulatory exclusion.

The attachment to this memorandum outlines in greater detail the type of projects that may qualify for a conditional exclusion from NSR as a pollution control project, the safeguards that are to be met, and the procedural steps that permitting authorities should follow in issuing an exclusion. Projects that do not meet these safeguards and procedural steps do not qualify for an exclusion from NSR under this policy. Pollution control projects potentially eligible for an exclusion (provided all applicable safeguards are met) include the installation of conventional or innovative emissions control equipment and projects undertaken to accommodate switching to an inherently less-polluting fuel, such as natural gas. Under this guidance, States may also exclude as pollution control projects some material and process changes (e.g., the switch to a less polluting coating, solvent, or refrigerant) and some other types of pollution prevention projects undertaken to reduce emissions of air pollutants subject to regulation under the Act.

The replacement of an existing emissions unit with a newer or different one (albeit more efficient and less polluting) or the reconstruction of an existing emissions unit does not qualify as a pollution control project. Furthermore, this guidance only applies to physical or operational changes whose primary function is the reduction of air pollutants subject to regulation under the Act at existing major sources. This policy does not apply to air pollution controls and emissions associated with a proposed new source. Similarly, the fabrication, manufacture or production of pollution control/prevention equipment and inherently less-polluting fuels or raw materials are not pollution control projects under this policy (e.g., a physical or operational change for the purpose of producing reformulated gasoline at a refinery is not a pollution control project).

It is EPA's experience that many bona fide pollution control projects are not subject to major NSR requirements for the simple reason that they result in a reduction in annual emissions at the source. In this way, these pollution control projects are outside major NSR coverage in accordance with the general rules for determining applicability of NSR to modifications at existing sources. However, some pollution control projects could result in significant potential or actual increases of some pollutants. These latter projects comprise the subcategory of pollution control projects that can benefit from this guidance.

A pollution control project must be, on balance, "environmentally beneficial" to be eligible for an exclusion. Further, an environmentally-beneficial pollution control project may be excluded from otherwise applicable major NSR requirements only under conditions that ensure that the project will not cause or contribute to a violation of a national ambient air quality standard (NAAQS), prevention of significant deterioration (PSD) increment, or adversely affect visibility or other air quality related value (AQRV). In order to assure that air quality concerns with these projects are adequately addressed, there are two substantive and two procedural safeguards which are to be followed by permitting authorities reviewing projects proposed for exclusion.

First, the permitting authority must determine that the proposed pollution control project, after consideration of the reduction in the targeted pollutant and any collateral effects, will be environmentally beneficial. Second, nothing in this guidance authorizes any pollution control project which would cause or contribute to a violation of a NAAQS, or PSD increment, or adversely impact an AQRV in a class I area. Consequently, in addition to this "environmentally-beneficial" standard, the permitting authority must ensure that adverse collateral environmental impacts from the project are identified, minimized, and, where appropriate, mitigated. For example, the source or the State must secure offsetting reductions in the case of a project which will result in a significant increase in a nonattainment pollutant. Where a significant collateral increase in actual emissions is expected to result from a pollution control project, the permitting authority must also assess whether the increase could adversely affect any national ambient air quality standard, PSD increment, or class I AQRV.

In addition to these substantive safeguards, EPA is specifying two procedural safeguards which are to be followed. First, since the exclusion under this interim guidance is only available on a case-by-case basis, sources seeking exclusion from major NSR requirements prior to the forthcoming EPA rulemaking on a pollution control project exclusion must, before beginning construction, obtain a determination by the permitting authority that a proposed project qualifies for an exclusion from major NSR requirements as a pollution control project. Second, in considering this request, the permitting authority must afford the public an opportunity to review and comment on the source's application for this exclusion. It is also important to note that any project excluded from major new source review as a pollution control project must still comply with all otherwise applicable requirements under the Act and the State implementation plan (SIP), including minor source permitting.

This guidance document does not supersede existing Federal or State regulations or approved SIP's. The policies set out in this memorandum and attachment are intended as guidance to be applied only prospectively (including those projects currently under evaluation for an exclusion) during the interim period until EPA takes action to revise its NSR rules, and do not represent final Agency action. This policy statement is not ripe for judicial review. Moreover, it is not intended, nor can it be relied upon, to create any rights enforceable by any party in litigation with the United States. Agency officials may decide to follow the guidance provided in this memorandum, or to act at variance with the guidance, based on an analysis of specific circumstances. The EPA also may change this guidance at any time without public notice. The EPA presently intends to address the matters discussed in this document in a forthcoming NSR rulemaking regarding proposed changes to the program resulting from the NSR Reform process and will take comment on these matters as part of that rulemaking.

As noted above, a detailed discussion of the types of projects potentially eligible for an exclusion from major NSR as a pollution control project, as well as the safeguards such projects must meet to qualify for the exclusion, is contained in the attachment to this memorandum. The Regional Offices should send this memorandum with the attachment to States within their jurisdiction. Questions concerning specific issues and cases should be directed to the appropriate EPA Regional Office. Regional Office staff may contact David Solomon, Chief, New Source Review Section, at (919) 541-5375, if they have any questions.

Attachment

cc: Air Branch Chief, Regions I-X
NSR Reform Subcommittee Members

Attachment

GUIDANCE ON EXCLUDING POLLUTION CONTROL PROJECTS FROM MAJOR NEW SOURCE REVIEW (NSR)

I. Purpose

The Environmental Protection Agency (EPA) presently expects to complete a rulemaking on an exclusion from major NSR for pollution control projects by early 1996. In the interim, certain types of projects (involving source categories other than utilities) may qualify on a case-by-case basis for an exclusion from major NSR as pollution control projects. Prior to EPA's final action on a regulatory exclusion, this attachment provides interim guidance for permitting authorities on the types of projects that may qualify on a case-by-case basis from major NSR as pollution control projects, including the substantive and procedural safeguards which apply.

II. Background

The NSR provisions of part C [prevention of significant deterioration (PSD)] and part D (nonattainment requirements) of title I of the Clean Air Act (Act) apply to both the construction of major new sources and the modification of existing major sources.[1] The modification provisions of the NSR programs in parts C and D are based on the broad definition of modification in section 111(a)(4) of the Act. That section contemplates a two-step test for determining whether activities at an existing major facility constitute a modification subject to new source requirements. In the first step, the reviewing authority determines whether a physical or operational change will occur. In the second step, the question is whether the physical or operational change will result in any increase in emissions of any regulated pollutant.

The definition of physical or operational change in section 111(a)(4) could, standing alone, encompass the most mundane activities at an industrial facility (even the repair or replacement of a single leaky pipe, or a insignificant change in the way that pipe is utilized). However, EPA has recognized that Congress did not intend to make every activity at a source subject to new source requirements under parts C and D. As a result, EPA has by regulation limited the reach of the modification provisions of parts C and D to only major modifications. Under NSR, a "major modification" is generally a physical change or change in the method of operation of a major stationary source which would result in a significant net emissions increase in the emissions of any regulated pollutant

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[1]The EPA's NSR regulations for nonattainment areas are set forth at 40 CFR 51.165, 52.24 and part 51, Appendix S. The PSD program is set forth in 40 CFR 52.21 and 51.166.

[see, e.g., 40 CFR 52.21(b)(2)(i)]. A "net emissions increase" is defined as the increase in "actual emissions" from the particular physical or operational change together with any other contemporaneous increases or decreases in actual emissions [see, e.g., 40 CFR 52.21(b)(3)(i)]. In order to trigger major new source review, the net emissions increase must exceed specified "significance" levels [see, e.g., 40 CFR 52.21(b)(2)(i) and 40 CFR 52.21(b)(23)]. The EPA has also adopted common-sense exclusions from the "physical or operational change" component of the definition of "major modification." For example, EPA's regulations contain exclusions for routine maintenance, repair, and replacement; for certain increases in the hours of operation or in the production rate; and for certain types of fuel switches [see, e.g., 40 CFR 52.21(b)(2)(iii)].

In the 1992 "WEPCO" rulemaking [57 FR 32314], EPA amended its PSD and nonattainment NSR regulations as they pertain to utilities by adding certain pollution control projects to the list of activities excluded from the definition of physical or operational changes. In taking that action, EPA stated it was largely formalizing an existing policy under which it had been excluding individual pollution control projects where it was found that the project "would be environmentally beneficial, taking into account ambient air quality" [57 FR at 32320; see also id., n. 15].[2]

The EPA has provided exclusions for pollution control projects in the form of "no action assurances" prior to November 15, 1990 and nonapplicability determinations based on Act changes as of November 15, 1990 (1990 Amendments). Generally, these exclusions addressed clean coal technology projects and fuel switches at electric utilities.

Because the WEPCO rulemaking was directed at the utility industry which faced "massive industry-wide undertakings of pollution control projects" to comply with the acid rain provisions of the Act [57 FR 32314], EPA limited the types of projects eligible for the exclusion to add-on controls and fuel switches at utilities. Thus, pollution control projects under the WEPCO rule are defined as:

> any activity or project undertaken at an existing electric utility steam generating unit for purposes of reducing emissions from such unit. Such activities or projects are <u>limited to</u>:

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[2]This guidance pertains only to source categories other than electric utilities, and EPA does not intend for this guidance to affect the WEPCO rulemaking in any way.

> (A) The installation of conventional or innovative pollution control technology, including but not limited to advanced flue gas desulfurization, sorbent injection for sulfur dioxide (SO_2) and nitrogen oxides (NO_x) controls and electrostatic precipitators;
>
> (B) An activity or project to accommodate switching to a fuel which is less polluting than the fuel in use prior to the activity or project . . .

[40 CFR 51.165(a)(1)(xxv) (emphasis added)]. The definition also includes certain clean coal technology demonstration projects. Id.

The EPA built two safeguards into the exclusion in the rulemaking. First, a project that meets the definition of pollution control project will not qualify for the exclusion where the "reviewing authority determines that (the proposed project) renders the unit less environmentally beneficial . . ." [see, e.g., 51.165(a)(1)(v)(C)(8)]. In the WEPCO rule, EPA did not provide any specific definition of the environmentally-beneficial standard, although it did indicate that the pollution control project provision "provides for a case-by-case assessment of the pollution control project's net emissions and overall impact on the environment" [57 FR 32321]. This provision is buttressed by a second safeguard that directs permitting authorities to evaluate the air quality impacts of pollution control projects that could--through collateral emissions increases or changes in utilization patterns--adversely impact local air quality [see 57 FR 32322]. This provision generally authorizes, as appropriate, a permitting authority to require modelling of emissions increases associated with a pollution control project. Id. More fundamentally, it explicitly states that no pollution control project under any circumstances may cause or contribute to violation of a national ambient air quality standard (NAAQS), PSD increment, or air quality related value (AQRV) in a class I area. Id.[3]

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[3]The WEPCO rule refers specifically to "visibility limitation" rather than "air quality related values." However, EPA clearly stated in the preamble to the final rule that permitting agencies have the authority to "solicit the views of others in taking any other appropriate remedial steps deemed necessary to protect class I areas. . .. The EPA emphasizes that all environmental impacts, including those on class I areas, can be considered. . .." [57 FR 32322]. Further, the statutory protections in section 165(d) plainly are intended to protect against any "adverse impact on the AQRV of such [class I] lands

As noted, the WEPCO rulemaking was expressly limited to existing electric utility steam generating units [see, e.g., 40 CFR 51.165(a)(1)(v)(C)(8) and 51.165(a)(1)(xx)]. The EPA limited the rulemaking to utilities because of the impending acid rain requirements under title IV of the Act, EPA's extensive experience with new source applicability issues for electric utilities, the general similarity of equipment, and the public availability of utility operating projections. The EPA indicated it would consider adopting a formal NSR pollution control project exclusion for other source categories as part of a separate NSR rulemaking. The rulemaking in question is now expected to be finalized by early 1996. On the other hand, the WEPCO rulemaking also noted that EPA's existing policy was, and would continue to be, to allow permitting authorities to exclude pollution control projects in other source categories on a case-by-case basis.

III. Case-By-Case Pollution Control Project Determinations

The following sections describe the type of projects that may be considered by permitting authorities for exclusion from major NSR as pollution control projects and two safeguards that permitting authorities are to use in evaluating such projects--the environmentally-beneficial test and an air quality impact assessment. To a large extent, these requirements are drawn from the WEPCO rulemaking. However, because the WEPCO rule was designed for a single source category, electric utilities, it cannot and does not serve as a complete template for this guidance. Therefore, the following descriptions expand upon the WEPCO rule in the scope of qualifying projects and in the specific elements inherent in the safeguards. These changes reflect the far more complicated task of evaluating pollution control projects at a wide variety of sources facing a myriad of Federal, State, and local clean air requirements.

Since the safeguards are an integral component of the exclusion, States must have the authority to impose the safeguards in approving an exclusion from major NSR under this policy. Thus, State or local permitting authorities in order to use this policy should provide statements to EPA describing and affirming the basis for its authority to impose these safeguards absent major NSR. Sources that obtain exclusions from permitting authorities that have not provided this affirmation of authority are at risk in seeking to rely on the exclusion issued by the

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(including visibility)." Based on this statutory provision, EPA believes that the proper focus of any air quality assessment for a pollution control project should be on visibility and any other relevant AQRV's for any class I areas that may be affected by the proposed project. Permitting authorities should notify Federal Land Managers where appropriate concerning pollution control projects which may adversely affect AQRV's in class I areas.

permitting agency, because EPA may subsequently determine that the project does not qualify as a pollution control project under this policy.

A. Types of Projects Covered

1. Add-On Controls and Fuel Switches

In the WEPCO rulemaking, EPA found that both add-on emissions control projects and fuel switches to less-polluting fuels could be considered to be pollution control projects. For the purposes of today's guidance, EPA affirms that these types of projects are appropriate candidates for a case-by-case exclusion as well. These types of projects include:

- the installation of conventional and advanced flue gas desulfurization and sorbent injection for SO_2;

- electrostatic precipitators, baghouses, high efficiency multiclones, and scrubbers for particulate or other pollutants;

- flue gas recirculation, low-NO_x burners, selective non-catalytic reduction and selective catalytic reduction for NO_x; and

- regenerative thermal oxidizers (RTO), catalytic oxidizers, condensers, thermal incinerators, flares and carbon adsorbers for volatile organic compounds (VOC) and toxic air pollutants.

Projects undertaken to accommodate switching to an inherently less-polluting fuel such as natural gas can also qualify for the exclusion. Any activity that is necessary to accommodate switching to a inherently less-polluting fuel is considered to be part of the pollution control project. In some instances, where the emissions unit's capability would otherwise be impaired as a result of the fuel switch, this may involve certain necessary changes to the pollution generating equipment (e.g., boiler) in order to maintain the normal operating capability of the unit at the time of the project.

2. Pollution Prevention Projects

It is EPA's policy to promote pollution prevention approaches and to remove regulatory barriers to sources seeking to develop and implement pollution prevention solutions to the extent allowed under the Act. For this reason, permitting authorities may also apply this exclusion to switches to inherently less-polluting raw materials and processes and certain other types of "pollution prevention" projects.[4] For instance, many VOC users will be making switches to water-based or powder-paint application systems as a strategy for meeting reasonably available control technology (RACT) or switching to a non-toxic VOC to comply with maximum achievable control technology (MACT) requirements.

Accordingly, under today's guidance, permitting authorities may consider excluding raw material substitutions, process changes and other pollution prevention strategies where the pollution control aspects of the project are clearly evident and will result in substantial emissions reductions per unit of output for one or more pollutants. In judging whether a pollution prevention project can be considered for exclusion as a pollution control project, permitting authorities may also consider as a relevant factor whether a project is being undertaken to bring a source into compliance with a MACT, RACT, or other Act requirement.

Although EPA is supportive of pollution control and prevention projects and strategies, special care must be taken in classifying a project as a pollution control project and in evaluating a project under a pollution control project exclusion. Virtually every modernization or upgrade project at an existing industrial facility which reduces inputs and lowers unit costs has the concurrent effect of lowering an emissions rate per unit of fuel, raw material or output. Nevertheless, it is clear that these major capital investments in industrial equipment are the very types of projects that Congress intended to address in the new source modification provisions [see Wisconsin Electric Power Co. v. Reilly, 893 F.2d 901, 907-10 (7th Cir. 1990) (rejecting contention that utility life extension project was not a physical or operational change); Puerto Rican Cement Co., Inc. v. EPA, 889 F.2d 292, 296-98 (1st Cir. 1989) (NSR applies to modernization project that decreases emissions per unit of output, but increases economic efficiency such that utilization may increase and result in net increase in actual emissions)]. Likewise, the replacement of an existing emissions unit with a newer or different one (albeit more efficient and less polluting) or the

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[4]For purposes of this guidance, pollution prevention means any activity that through process changes, product reformulation or redesign, or substitution of less polluting raw materials, eliminates or reduces the release of air pollutants and other pollutants to the environment (including fugitive emissions) prior to recycling, treatment, or disposal; it does not mean recycling (other than certain "in-process recycling" practices), energy recovery, treatment, or disposal [see Pollution Prevention Act of 1990 section 6602(b) and section 6603(5)(A) and (B); see also "EPA Definition of 'Pollution Prevention,'" memorandum from F. Henry Habicht II, May 28, 1992].

reconstruction of an existing emissions unit would not qualify as a pollution control project. Adopting a policy that automatically excludes from NSR any project that, while lowering operating costs or improving performance, coincidentally lowers a unit's emissions rate, would improperly exclude almost all modifications to existing emissions units, including those that are likely to increase utilization and therefore result in overall higher levels of emissions.

In order to limit this exclusion to the subset of pollution prevention projects that will in fact lower annual emissions at a source, permitting authorities should not exclude as pollution control projects any pollution prevention project that can be reasonably expected to result in an increase in the utilization of the affected emissions unit(s). For example, projects which significantly increase capacity, decrease production costs, or improve product marketability can be expected to affect utilization patterns. With these changes, the environment may or may not see a reduction in overall source emissions; it depends on the source's operations after the change, which cannot be predicted with any certainty.[5] This is not to say that these types of projects are necessarily subject to major NSR requirements, only that they should not be excluded as pollution control projects under this guidance. The EPA may consider different approaches to excluding pollution prevention projects from major NSR requirements in the upcoming NSR rulemaking. Under this guidance, however, permitting authorities should carefully review proposed pollution prevention projects to evaluate whether utilization of the source will increase as a result of the project.

Furthermore, permitting authorities should have the authority to monitor utilization of an affected emissions unit or source for a reasonable period of time subsequent to the project to verify what effect, if any, the project has on utilization. In cases where the project has clearly caused an increase in utilization, the permitting authority may need to reevaluate the basis for the original exclusion to verify that an exclusion is still appropriate and to ensure that all applicable safeguards are being met.

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[5] This is in marked contrast to the addition of pollution control equipment which typically does not, in EPA's experience, result in any increase in the source's utilization of the emission unit in question. In the few instances where this presumption is not true, the safeguards discussed in the next section should provide adequate environmental protections for these additions of pollution control equipment.

B. Safeguards

The following safeguards are necessary to assure that projects being considered for an exclusion qualify as environmentally beneficial pollution control projects and do not have air quality impacts which would preclude the exclusion. Consequently, a project that does not meet these safeguards does not qualify for an exclusion under this policy.

1. Environmentally-Beneficial Test

Projects that meet the definition of a pollution control project outlined above may nonetheless cause collateral emissions increases or have other adverse impacts. For instance, a large VOC incinerator, while substantially eliminating VOC emissions, may generate sizeable NO_x emissions well in excess of significance levels. To protect against these sorts of problems, EPA in the WEPCO rule provided for an assessment of the overall environmental impact of a project and the specific impact, if any, on air quality. The EPA believes that this safeguard is appropriate in this policy as well.

Unless information regarding a specific case indicates otherwise, the types of pollution control projects listed in III. A. 1. above can be presumed, by their nature, to be environmentally beneficial. This presumption arises from EPA's experience that historically these are the very types of pollution controls applied to new and modified emissions units. The presumption does not apply, however, where there is reason to believe that 1) the controls will not be designed, operated or maintained in a manner consistent with standard and reasonable practices; or 2) collateral emissions increases have not been adequately addressed as discussed below.

In making a determination as to whether a project is environmentally beneficial, the permitting authority must consider the types and quantity of air pollutants emitted before and after the project, as well as other relevant environmental factors. While because of the case-by-case nature of projects it is not possible to list all factors which should be considered in any particular case, several concerns can be noted.

First, pollution control projects which result in an increase in non-targeted pollutants should be reviewed to determine that the collateral increase has been minimized and will not result in environmental harm. Minimization here does not mean that the permitting agency should conduct a BACT-type review or necessarily prescribe add-on control equipment to treat the collateral increase. Rather, minimization means that, within the physical configuration and operational standards usually associated with such a control device or strategy, the source has taken reasonable measures to keep any collateral increase to a minimum. For instance, the permitting authority could require that a low-NO_x burner project be subject to temperature and other appropriate combustion standards so that carbon monoxide (CO) emissions are kept to a minimum, but would not review the project for a CO catalyst or other add-on type options. In addition, a State's RACT or MACT rule may have explicitly considered measures for minimizing a collateral increase for a class or category of pollution control projects and requires a standard of best practices to minimize such collateral increases. In such cases, the need to minimize collateral increase from the covered class or category of pollution control projects can be presumed to have been adequately addressed in the rule.

In addition, a project which would result in an unacceptable increased risk due to the release of air toxics should not be considered environmentally beneficial. It is EPA's experience, however, that most projects undertaken to reduce emissions, especially add-on controls and fuel switches, result in concurrent reductions in air toxics. The EPA expects that many pollution control projects seeking an exclusion under this guidance will be for the purpose of complying with MACT requirements for reductions in air toxics. Consequently, unless there is reason to believe otherwise, permitting agencies may presume that such projects by their nature will result in reduced risks from air toxics.

2. Additional Air Quality Impacts Assessments

(a) General

Nothing in the Act or EPA's implementing regulations would allow a permitting authority to approve a pollution control project resulting in an emissions increase that would cause or contribute to a violation of a NAAQS or PSD increment, or adversely impact visibility or other AQRV in a class I area [see, e.g., Act sections 110(a)(2)(C), 165, 169A(b), 173]. Accordingly, this guidance is not intended to allow any project to violate any of these air quality standards.

As discussed above, it is possible that a pollution control project--either through an increase in an emissions rate of a collateral pollutant or through a change in utilization--will cause an increase in actual emissions, which in turn could cause or contribute to a violation of a NAAQS or increment or adversely impact AQRV's. For this reason, in the WEPCO rule the EPA required sources to address whenever 1) the proposed change would result in a significant net increase in actual emissions of any criteria pollutant over levels used for that source in the most recent air quality impact analysis; and 2) the permitting authority has reason to believe that such an increase would cause or contribute to a violation of a NAAQS, increment or visibility limitation. If an air quality impact analysis indicates that the increase in emissions will cause or contribute to a violation of any ambient standard, PSD increment, or AQRV, the pollution control exclusion does not apply.

The EPA believes that this safeguard needs to be applied here as well. Thus, where a pollution control project will result in a significant increase in emissions and that increased level has not been previously analyzed for its air quality impact and raises the possibility of a NAAQS, increment, or AQRV violation, the permitting authority is to require the source to provide an air quality analysis sufficient to demonstrate the impact of the project. The EPA will not necessarily require that the increase be modeled, but the source must provide sufficient data to satisfy the permitting authority that the new levels of emissions will not cause a NAAQS or increment violation and will not adversely impact the AQRV's of nearby potentially affected class I areas.

In the case of nonattainment areas, the State or the source must provide offsetting emissions reductions for any significant increase in a nonattainment pollutant from the pollution control project. In other words, if a significant collateral increase of a nonattainment pollutant resulting from a pollution control project is not offset on at least a one-to-one ratio then the pollution control project would not qualify as environmentally beneficial.[6] However, rather than having to apply offsets on a case-by-case basis, States may consider adopting (as part of their attainment plans) specific control measures or strategies for the purpose of generating offsets to mitigate the projected collateral emissions increases from a class or category of pollution control projects.

(b) Determination of Increase in Emissions

The question of whether a proposed project will result in an emissions increase over pre-modification levels of actual emissions is both complicated and contentious. It is a question that has been debated by the New Source Review Reform Subcommittee of the Clean Air Act Advisory Committee and is expected to be revisited by EPA in the same upcoming rulemaking that will consider adopting a pollution control project exclusion. In the interim, EPA is adopting a simplified approach

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[6]Regardless of the severity of the classification of the nonattainment area, a one-to-one offset ratio will be considered sufficient under this policy to mitigate a collateral increase from a pollution control project. States may, however, require offset ratios that are greater than one-to-one.

to determining whether a pollution control project will result in increased emissions.

The approach in this policy is premised on the fact that EPA does not expect the vast majority of these pollution control projects to change established utilization patterns at the source. As discussed in the previous section, it is EPA's experience that add-on controls do not impact utilization, and pollution prevention projects that could increase utilization may not be excluded under this guidance. Therefore, in most cases it will be very easy to calculate the emissions after the change: the product of the new emissions rate times the existing utilization rate. In the case of a pollution control project that collaterally increases a non-targeted pollutant, the actual increase (calculated using the new emissions rate and current utilization pattern) would need to be analyzed to determine its air quality impact.

The permitting authority may presume that projects meeting the definition outlined in section III(A)(1) will not change utilization patterns. However, the permitting authority is to reject this presumption where there is reason to believe that the project will result in debottlenecking, loadshifting to take advantage of the control equipment, or other meaningful increase in the use of the unit above current levels. Where the project will increase utilization and emissions, the associated emissions increases are calculated based on the post-modification potential to emit of the unit considering the application of the proposed controls. In such cases the permitting agency should consider the projected increase in emissions as collateral to the project and determine whether, notwithstanding the emissions increases, the project is still environmentally beneficial and meets all applicable safeguards.

In certain limited circumstances, a permitting agency may take action to impose federally-enforceable limits on the magnitude of a projected collateral emissions increase to ensure that all safeguards are met. For example, where the data used to assess a projected collateral emissions increase is questionable and there is reason to believe that emissions in excess of the projected increase would violate an applicable air quality standard or significantly exceed the quantity of offsets provided, restrictions on the magnitude of the collateral increase may be necessary to ensure compliance with the applicable safeguards.

IV. Procedural Safeguards

Because EPA has not yet promulgated regulations governing a generally applicable pollution control project exclusion from major NSR (other than for electric utilities), permitting authorities must consider and approve requests for an exclusion on a case-by-case basis, and the exclusion is not self-executing. Instead, sources must receive case-by-case approval from the permitting authority pursuant to a minor NSR permitting process, State nonapplicability determination or similar process. [Nothing in this guidance voids or creates an exclusion from any applicable minor source preconstruction review requirement in any SIP that has been approved pursuant to section 110(a)(2)(C) and 40 CFR 51.160-164.] This process should also provide that the application for the exclusion and the permitting agency's proposed decision thereon be subject to public notice and the opportunity for public and EPA written comment. In those limited cases where the applicable SIP already exempts a class or category of pollution controls project from the minor source permitting public notice and comment requirements, and where no collateral increases are expected (e.g., the installation of a baghouse) and all otherwise applicable environmental safeguards are complied with, public notice and comment need not be provided for such projects. However, even in such circumstances, the permitting agency should provide advance notice to EPA when it applies this policy to provide an exclusion. For standard-wide applications to groups of sources (e.g., RACT or MACT), the notice may be provided to EPA at the time the permitting authority intends to issue a pollution control exclusion for the class or category of sources and thereafter notice need not be given to EPA on an individual basis for sources within the noticed group.

V. Emission Reduction Credits

In general, certain pollution control projects which have been approved for an exclusion from major NSR may result in emission reductions which can serve as NSR offsets or netting credits. All or part of the emission reductions equal to the difference between the pre-modification actual and post-modification potential emissions for the decreased pollutant may serve as credits provided that 1) the project will not result in a significant collateral increase in actual emissions of any criteria pollutant, 2) the project is still considered environmentally beneficial, and 3) all otherwise applicable criteria for the crediting of such reductions are met (e.g., quantifiable, surplus, permanent, and enforceable). Where an excluded pollution control project results in a significant collateral increase of a criteria pollutant, emissions reduction credits from the pollution control project for the controlled pollutant may still be granted provided, in addition to 2) and 3) above, the actual collateral increase is reduced below the applicable significance level, either through contemporaneous reductions at the source or external offsets. However, neither the exclusion from major NSR nor any credit (full or partial) for emission reductions should be granted by the permitting authority where the type or amount of the emissions increase which would result from the use of such credits would lessen the environmental benefit associated with the pollution control project to the point where the project would not have initially qualified for an exclusion.

IV. Illustrative Examples

The following examples illustrate some of the guiding principles and safeguards discussed above in reviewing proposed pollution control projects for an exclusion from major NSR.

Example 1

PROJECT DESCRIPTION: A chemical manufacturing facility in an attainment area for all pollutants is proposing to install a RTO to reduce VOC emissions (including emissions of some hazardous pollutants) at the plant by about 3000 tons per year (tpy). The emissions reductions from the RTO are currently voluntary, but may be necessary in the future for title III MACT compliance. Although the RTO has been designed to minimize NO_x emissions, it will produce 200 tpy of new NO_x emissions due to the unique composition of the emissions stream. There is no information about the project to rebut a presumption that the project will not change utilization of the source. Aside from the NO_x increase there are no other environmental impacts known to be associated with the project.

EVALUATION: As a qualifying add-on control device, the project may be considered a pollution control project and may be considered for an exclusion. The permitting agency should: 1) verify that the NO_x increase has been minimized to the extent practicable, 2) confirm (through modeling or other appropriate means) that the actual significant increase in NO_x emissions does not violate the applicable NAAQS,[7] PSD increment, or adversely impact any Class I area AQRV, and 3) apply all otherwise applicable SIP and minor source permitting requirements, including opportunity for public notice and comment.

Example 2

PROJECT DESCRIPTION: A source proposes to replace an existing coal-fired boiler with a gas-fired turbine as part of a cogeneration project. The new turbine is an exact replacement for the energy needs supplied by the existing boiler and will emit less of each pollutant on an hourly basis than the boiler did.

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[7] If the source were located in an area in which nonattainment NSR applied to NO_x emissions increases, 200 tons of NO_x offset credits would be required for the project to be eligible for an exclusion.

EVALUATION: The replacement of an existing emissions unit with a new unit (albeit more efficient and less polluting) does not qualify for an exclusion as a pollution control project. The company can, however, use any otherwise applicable netting credits from the removal of the existing boiler to seek to net the new unit out of major NSR.

Example 3

PROJECT DESCRIPTION: A source plans to physically renovate and upgrade an existing process line by making certain changes to the existing process, including extensive modifications to emissions units. Following the changes, the source will expand production and manufacture and market a new product line. The project will cause an increase in the economic efficiency of the line. The renovated line will also be less polluting on a per-product basis than the original configuration.

EVALUATION: The change is not eligible for an exclusion as a pollution control project. On balance, the project does not have clearly evident pollution control aspects, and the resultant decrease in the per-product emissions rate (or factor) is incidental to the project. The project is a physical change or change in the method of operation that will increase efficiency and productivity.

Example 4

PROJECT DESCRIPTION: In response to the phaseout of chlorofluorocarbons (CFC) under title VI of the Act, a major source is proposing to substitute a less ozone-depleting substance (e.g., HCFC-141b) for one it currently uses that has a greater ozone depleting potential (e.g., CFC-11). A larger amount of the less-ozone depleting substance will have to be used. No other changes are proposed.

EVALUATION: The project may be considered a pollution control project and may be considered for an exclusion. The permitting agency should verify that 1) actual annual emissions of HCFC-141b after the proposed switch will cause less stratospheric ozone depletion than current annual emissions of CFC-11; 2) the proposed switch will not change utilization patterns or increase emissions of any other pollutant which would impact a NAAQS, PSD increment, or AQRV and will not cause any cross-media harm, including any unacceptable increased risk associated with toxic air pollutants; and 3) apply all otherwise applicable SIP and minor source permitting requirements, including opportunity for public notice and comment.

Example 5

PROJECT DESCRIPTION: An existing landfill proposes to install either flares or energy recovery equipment [i.e., turbines or internal combustion (IC) engines]. The reductions from the project are estimated at over 1000 tpy of VOC and are currently not necessary to meet Act requirements, but may be necessary some time in the future. In case A the project is the replacement of an existing flare or energy system and no increase in NO_x emissions will occur. In case B, the equipment is a first time installation and will result in a 100 tpy increase in NO_x. In case C, the equipment is an addition to existing equipment which will accommodate additional landfill gas (resulting from increased gas generation and/or capture consistent with the current permitted limits for growth at the landfill) and will result in a 50 tpy increase in NO_x.

EVALUATION: Projects A, B, and C may be considered pollution control projects and may be considered for an exclusion; however, in cases B and C, if the landfill is located in an area required to satisfy nonattainment NSR for NO_x emissions, the source would be required to obtain NO_x offsets at a ratio of at least 1:1 for the project to be considered for an exclusion. [NOTE: VOC-NO_x netting and trading for NSR purposes may be discussed in the upcoming NSR rulemaking, but it is beyond the scope of this guidance.] Although neither turbines or IC engines are listed in section III.A.1 as add-on control devices and would normally not be considered pollution control projects, in this specific application they serve the same function as a flare, namely to reduce VOC emissions at the landfill with the added incidental benefit of producing useful energy in the process.[8]

The permitting agency should: 1) verify that the NO_x increase has been minimized to the extent practicable; 2) confirm (through modeling or other appropriate means) that the actual significant increase in NO_x emissions will not violate the

[8]The production of energy here is incidental to the project and is not a factor in qualifying the project for an exclusion as a pollution control project. In addition, any supplemental or co-firing of non-landfill gas fuels (e.g., natural gas, oil) would disqualify the project from being considered a pollution control project. The fuels would be used to maximize any economic benefit from the project and not for the purpose of pollution control at the landfill. However, the use of an alternative fuel solely as a backup fuel to be used only during brief and infrequent start-up or emergency situations would not necessarily disqualify an energy recovery project from being considered a pollution control project.

applicable NAAQS, PSD increment, or adversely impact any AQRV; and 3) apply all otherwise applicable SIP and minor source and, as noted above, in cases B and C ensures that NO_x offsets are provided in an area in which nonattainment review applies to NO_x emissions increases. permitting requirements, including opportunity for public notice and comment.

APPENDIX F

MAP AND LISTING OF NONATTAINMENT AREAS

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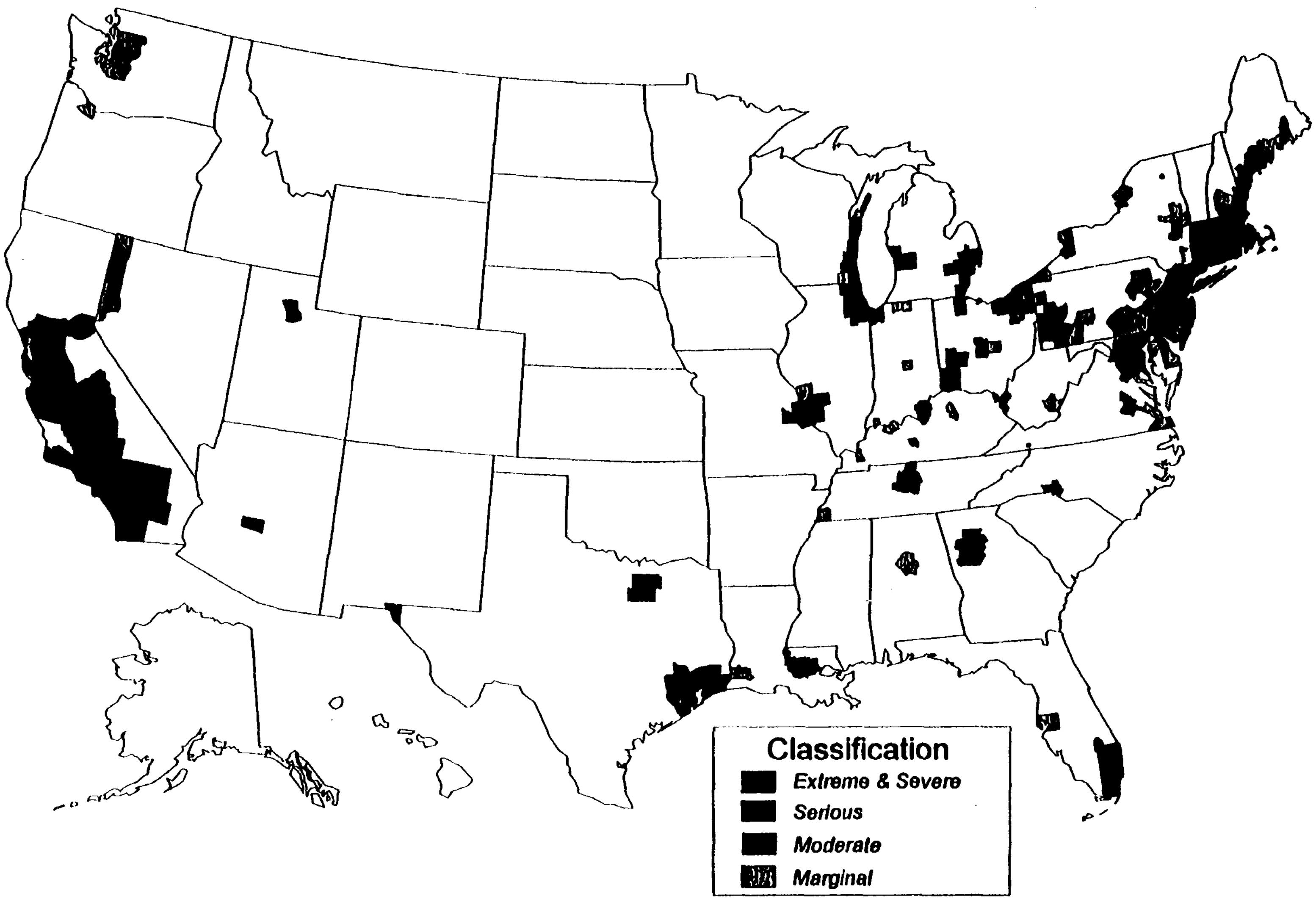
Areas Designated Nonattainment for Ozone



Designated Nonattainment Areas as of September 1994

Note: Unclassified areas are not shown.

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Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update A.Q. Value	1991-93 Update Average Est. Exc.	1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
AL	Birmingham NA Area	Marginal	0.124	0.7	0.125	2.0
AZ	Phoenix	Moderate	0.147	4.0 (#4)	0.126	2.0
CA	Los Angeles South Coast Air Basin	Extreme	0.300	104.3	0.250	97.6
CA	Monterey Bay Unified NA Area	Moderate	0.108	0.4	0.104	0.0
CA	Sacramento Metro NA Area	Serious	0.150	9.7	0.150	3.6
CA	San Diego NA Area	Severe 15	0.150	11.8	0.159	4.0
CA	San Francisco-Bay NA Area	Moderate	0.120	0.7	0.130	2.0
CA	San Joaquin Valley NA Area	Serious	0.159	18.9	0.159	27.5
CA	Santa Barbara-Santa Maria-Lompoc	Moderate	0.123	1.0	0.114	0.0
CA	Southeast Desert Modified AQMD	Severe 17	0.200	59.3	0.180	72.6
CA	Ventura Co NA Area	Severe 15	0.150	15.9	0.144	9.0
CT	Greater Connecticut NA Area	Serious	0.158	7.5	0.153	6.0
DC-MD-VA	Washington NA Area	Serious	0.137	1.4	0.132	3.1
DE	Sussex Co NA Area	Marginal	0.118	1.0	0.115	0.0
FL	Miami-Fort Lauderdale-W. Palm Beach	Moderate	0.106	0.0	0.122	1.0
FL	Tampa-St. Petersburg-Clearwater	Marginal	0.110	0.0	0.100	0.0
GA	Atlanta NA Area	Serious	0.149	4.2	0.162	4.3
IL-IN	Chicago-Gary-Lake County NA Area	Severe 17	0.145	4.7 (#5)	0.125	2.4
IL	Jersey Co NA Area	Marginal	0.112	0.7	0.127	2.0
IN	Evansville NA Area	Marginal	0.110	0.0	0.110	0.0
IN	Indianapolis NA Area	Marginal	0.104	0.0	0.104	0.0
IN	South Bend-Elkhart NA Area	Marginal	0.103	0.0	0.096	0.0
KY	Edmonson Co NA Area	Marginal	0.091	0.0	0.092	0.0
KY-WV	Huntington-Ashland NA Area	Moderate	0.122	1.0	0.122	1.0
KY	Lexington-Fayette NA Area	Marginal	0.100	0.0	0.103	0.0
KY-IN	Louisville NA Area	Moderate	0.130	2.2	0.140	2.0
KY	Owensboro NA Area	Marginal	0.104	0.0	0.106	0.0
KY	Paducah NA Area	Marginal	0.106	0.0	0.112	0.0
LA	Baton Rouge NA Area	Serious	0.135	1.8	0.127	3.0
LA	Lake Charles NA Area	Marginal	0.132	1.3 (#6)	0.108	0.0
MA-NH	Boston-Lawrence-Worcester NA Area	Serious	0.137	3.1	0.155	4.0
MA	Springfield (W. Mass) NA Area	Serious	0.141	4.6	0.133	6.2
MD	Baltimore NA Area	Severe 15	0.150	4.8	0.146	6.2
MD	Kent County and Queen Anne's County	Marginal	0.133	2.8	0.128	2.0
ME	Hancock Co and Waldo Co NA Area	Marginal	0.112	1.3 (#7)	0.094	0.0
ME	Knox Co and Lincoln Co NA Area	Moderate	0.134	2.3	0.122	1.2
ME	Lewiston - Auburn NA Area	Moderate	0.106	0.3	0.096	0.0
ME	Portland NA Area	Moderate	0.147	11.8	0.125	3.8
MI	Detroit-Ann Arbor NA Area	Moderate	0.122	1.0	0.122	1.0

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93, continued

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update A.Q. Value	1991-93 Update Average Est. Exc.	1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
MI	Grands Rapids NA Area	Moderate	0.146	3.4 (#8)	0.094	1.0
MI	Muskegon NA Area	Moderate	0.141	2.3	0.104	1.0
MO-KS	Kansas City NA Area	Attainment	0.114	0.3	0.114	1.0
MO-IL	St. Louis NA Area	Moderate	0.132	1.7	0.126	2.1
NC	Charlotte-Gastonia NA Area	Moderate	0.119	0.7	0.137	2.1
NC	Greensboro-Winston-Salem-High Point	Attainment	0.113	0.3	0.121	1.0
NC	Raleigh-Durham NA Area	Attainment	0.118	0.7	0.128	2.1
NH	Manchester NA Area	Marginal	0.087	0.0	0.086	0.0
NH	Portsmouth-Dover-Rochester, NH	Serious	0.143	2.2	0.107	1.1
NJ	Atlantic City NA Area	Moderate	0.122	1.0	0.115	0.0
NV	Reno	Marginal	0.089	0.0	0.089	0.0
NY	Albany-Schenectady-Troy NA Area	Marginal	0.104	0.0	0.106	0.0
NY	Buffalo-Niagara Falls NA Area	Marginal	0.106	0.0	0.090	0.0
NY	Essex Co NA Area	Marginal	0.116	0.0	0.100	0.0
NY	Jefferson Co NA Area	Marginal	0.110	0.0	0.092	0.0
NY-NJ-CT	New York-N. New Jersey-Long Island	Severe 17	0.158	6.1	0.165	6.0
NY	Poughkeepsie NA Area	Marginal	0.126	1.4	0.139	2.0
OH	Canton NA Area	Marginal	0.109	0.3	0.109	0.0
OH-KY	Cincinnati-Hamilton NA Area	Moderate	0.125	1.3	0.121	1.0
OH	Cleveland-Akron-Lorain NA Area	Moderate	0.125	1.7 (#9)	0.117	0.0
OH	Columbus NA Area	Marginal	0.118	0.3	0.105	0.0
OH	Dayton-Springfield NA Area	Moderate	0.112	0.0	0.120	1.0
OH	Toledo NA Area	Moderate	0.120	0.3	0.121	1.0
OH-PA	Youngstown-Warren-Sharon NA Area	Marginal	0.113	0.3	0.120	1.0
OR	Portland-Vancouver AQMA NA Area	Marginal	0.108	0.7	0.103	0.0
PA-NJ	Allentown-Bethlehem-Easton NA Area	Marginal	0.115	0.0	0.110	0.0
PA	Altoona NA Area	Marginal	0.105	0.0	0.100	0.0
PA	Erie NA Area	Marginal	0.110	0.0	0.107	0.0
PA	Harrisburg-Lebanon-Carlisle NA	Marginal	0.111	0.0	0.118	0.0
PA	Johnstown NA Area	Marginal	0.107	0.0	0.099	0.0
PA	Lancaster NA Area	Marginal	0.118	0.3	0.118	1.0
PA-NJ-DE-MD	Philadelphia-Wilmington-Trenton	Severe 15	0.156	10.3	0.147	5.2
PA	Pittsburgh-Beaver Valley NA Area	Moderate	0.119	0.7	0.124	0.0
PA	Reading NA Area	Moderate	0.118	0.3	0.110	0.0
PA	Scranton-Wilkes-Barre NA Area	Marginal	0.117	0.4	0.112	0.0
PA	York NA Area	Marginal	0.113	0.0	0.112	0.0

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93, continued

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update A.Q. Value	1991-93 Update Average Est. Exc.	1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
RI	Providence (all of RI) NA Area	Serious	0.152	4.0	0.117	1.4
SC	Cherokee Co NA Area	Attainment	0.105	0.3	0.108	0.0
TN	Knoxville NA Area	Attainment	0.118	0.0	0.120	0.0
TN	Memphis NA Area	Marginal	0.115	0.3	0.119	1.0
TN	Nashville NA Area	Moderate	0.124	1.1	0.126	2.1
TX	Beaumont-Port Arthur NA Area	Serious	0.130	2.7	0.122	0.0
TX	Dallas-Fort Worth NA Area	Moderate	0.141	2.0	0.140	2.3
TX	El Paso NA Area	Serious	0.136	3.7	0.135	4.1
TX	Houston-Galveston-Brazoria NA	Severe 17	0.200	6.3	0.197	10.4
UT	Salt Lake City-Ogden NA Area	Moderate	0.106	0.0	0.104	0.0
VA	Norfolk-Virginia Beach-Newport News	Marginal	0.131	1.7	0.131	3.0
VA	Richmond-Petersburg NA Area	Moderate	0.128	1.4	0.132	3.1
VA	Smyth County NA Area	Marginal	ND	ND (#10)	ND	ND
WA	Seattle - Tacoma NA Area	Marginal	0.105	0.0	0.100	0.0
WI	Door Co NA Area	Marginal	0.125	1.6	0.098	0.0
WI	Kewaunee Co NA Area	Moderate	0.107	0.8	0.095	0.0
WI	Manitowoc Co NA Area	Moderate	0.132	2.0	0.095	0.0
WI	Milwaukee-Racine NA Area	Severe 17	0.148	3.9	0.125	2.4
WI	Sheboygan NA Area	Moderate	0.139	2.6 (#11)	0.095	0.0
WI	Walworth Co NA Area	Marginal	0.120	0.3	0.093	0.0
WV	Charleston NA Area	Attainment	0.106	0.3	0.075	0.0
WV	Greenbrier NA Area	Marginal	0.101	0.4	0.090	0.0
WV	Parkersburg NA Area	Attainment	0.118	0.0	0.104	0.0

91 Nonattainment Areas

SOURCE: EPA's air quality data system, the Aerometric Information Retrieval System (AIRS), with supplemental data from EPA Regional Offices.

NOTES:

1. Designations and classifications for ozone nonattainment areas as published in the Federal Register, 40 CFR Part 81. *Unclassified and transitional nonattainment areas are not included in this listing.*

2. The updated air quality value is estimated for the 1991-93 period using EPA guidance for calculating design values (Laxton Memorandum, June 18, 1990). Generally, the fourth highest monitored value with 3 complete years of data is

selected as the updated air quality value because the standard allows one exceedance for each year. It is important to note that the 1990 Clean Air Act Amendments required that O_3 nonattainment areas be classified on the basis of the design value at the time the Amendments were passed, generally the 1987-89 period was used.

3. The National Ambient Air Quality standard for ozone is 0.12 parts per million (ppm) daily maximum 1-hour average not to be exceeded more than once per year on average. The average estimated number of exceedances column shows the number of days the 0.12 ppm standard was exceeded on average at the site recording the highest updated air quality value. This is done after adjustment for incomplete, or missing days, during the 3-year period, 1991-93. The last two columns contain data from the site recording the highest second daily maximum 1-hour concentration in 1993. The last column shows the estimated exceedances for 1993 at the site recording the highest second maximum 1-hour concentration listed in the previous column.

4. Special purpose monitoring (SPM) operating during the ozone monitoring season.

5. The nonattainment/updated air quality value site for the Chicago NA Area is in Kenosha County, WI.

6. The Regional Office is reviewing the status of the area based on data through 1994.

7. Incomplete data reported in 1991.

8. Calculation of the updated air quality value and estimated exceedances adjusted to account for start-up of a LMOS Study site with data only in 1991.

9. Data from a monitoring site located at the water treatment plant not used due to localized interference.

10. The site was located atop Whitetop Mountain, VA as part of the Mountain Cloud Study. Site elevation is 5520 feet. No data reported after 1988. This is a rural transport area. The nonattainment area is that portion of Whitetop Mountain above 4500 feet elevation.

11. Calculation of estimated exceedances adjusted for Wisconsin ozone season not yet reflected in AIRS.

Region I

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update A.Q. Value	1991-93 Update Average Est. Exc.	1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
CT	Greater Connecticut NA Area	Serious	0.158	7.5	0.153	6.0
MA-NH	Boston-Lawrence-Worcester NA Area	Serious	0.137	3.1	0.155	4.0
MA	Springfield (W. Mass) NA Area	Serious	0.141	4.6	0.133	6.2
ME	Hancock Co and Waldo Co NA Area	Marginal	0.112	1.3 (#7)	0.094	0.0
ME	Knox Co and Lincoln Co NA Area	Moderate	0.134	2.3	0.122	1.2
ME	Lewiston - Auburn NA Area	Moderate	0.106	0.3	0.096	0.0
ME	Portland NA Area	Moderate	0.147	11.8	0.125	3.8
NH	Manchester NA Area	Marginal	0.087	0.0	0.086	0.0
NH	Portsmouth-Dover-Rochester, NH	Serious	0.143	2.2	0.107	1.1
NY-NJ-CT	New York-N. New Jersey-Long Island	Severe 17	0.158	6.1	0.165	6.0
RI	Providence (all of RI) NA Area	Serious	0.152	4.0	0.117	1.4

Region II

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update A.Q. Value	1991-93 Update Average Est. Exc.	1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
NJ	Atlantic City NA Area	Moderate	0.122	1.0	0.115	0.0
NY	Albany-Schenectady-Troy NA Area	Marginal	0.104	0.0	0.106	0.0
NY	Buffalo-Niagara Falls NA Area	Marginal	0.106	0.0	0.090	0.0
NY	Essex Co NA Area	Marginal	0.116	0.0	0.100	0.0
NY	Jefferson Co NA Area	Marginal	0.110	0.0	0.092	0.0
NY-NJ-CT	New York-N. New Jersey-Long Island	Severe 17	0.158	6.1	0.165	6.0
NY	Poughkeepsie NA Area	Marginal	0.126	1.4	0.139	2.0
PA-NJ	Allentown-Bethlehem-Easton NA Area	Marginal	0.115	0.0	0.110	0.0
PA-NJ-DE-MD	Philadelphia-Wilmington-Trenton	Severe 15	0.156	10.3	0.147	5.2

Region III

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update A.Q. Value	1991-93 Update Average Est. Exc.	1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
DC-MD-VA	Washington NA Area	Serious	0.137	1.4	0.132	3.1
DE	Sussex Co NA Area	Marginal	0.118	1.0	0.115	0.0
MD	Baltimore NA Area	Severe 15	0.150	4.8	0.146	6.2
MD	Kent County and Queen Anne's County	Marginal	0.133	2.8	0.128	2.0
OH-PA	Youngstown-Warren-Sharon NA Area	Marginal	0.113	0.3	0.120	1.0
PA-NJ	Allentown-Bethlehem-Easton NA Area	Marginal	0.115	0.0	0.110	0.0
PA	Altoona NA Area	Marginal	0.105	0.0	0.100	0.0
PA	Erie NA Area	Marginal	0.110	0.0	0.107	0.0
PA	Harrisburg-Lebanon-Carlisle NA	Marginal	0.111	0.0	0.118	0.0
PA	Johnstown NA Area	Marginal	0.107	0.0	0.099	0.0
PA	Lancaster NA Area	Marginal	0.118	0.3	0.118	1.0
PA-NJ-DE-MD	Philadelphia-Wilmington-Trenton	Severe 15	0.156	10.3	0.147	5.2
PA	Pittsburgh-Beaver Valley NA Area	Moderate	0.119	0.7	0.124	0.0
PA	Reading NA Area	Moderate	0.118	0.3	0.110	0.0
PA	Scranton-Wilkes-Barre NA Area	Marginal	0.117	0.4	0.112	0.0
PA	York NA Area	Marginal	0.113	0.0	0.112	0.0
WV	Charleston NA Area	Moderate	0.106	0.3	0.075	0.0
WV	Greenbrier NA Area	Marginal	0.101	0.4	0.090	0.0
WV	Parkersburg NA Area	Moderate	0.118	0.0	0.104	0.0
VA	Norfolk-Virginia Beach-Newport News	Marginal	0.131	1.7	0.131	3.0
VA	Richmond-Petersburg NA Area	Moderate	0.128	1.4	0.132	3.1
VA	Smyth County NA Area	Marginal	ND	ND (#10)	ND	ND

Region IV

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update A.Q. Value	1991-93 Update Average Est. Exc.	1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
AL	Birmingham NA Area	Marginal	0.124	0.7	0.125	2.0
FL	Miami-Fort Lauderdale-W. Palm Beach	Moderate	0.106	0.0	0.122	1.0
FL	Tampa-St. Petersburg-Clearwater	Marginal	0.110	0.0	0.100	0.0
GA	Atlanta NA Area	Serious	0.149	4.2	0.162	4.3
KY	Edmonson Co NA Area	Marginal	0.091	0.0	0.092	0.0
KY-WV	Huntington-Ashland NA Area	Moderate	0.122	1.0	0.122	1.0
KY	Lexington-Fayette NA Area	Marginal	0.100	0.0	0.103	0.0
KY-IN	Louisville NA Area	Moderate	0.130	2.2	0.140	2.0
KY	Owensboro NA Area	Marginal	0.104	0.0	0.106	0.0
KY	Paducah NA Area	Marginal	0.106	0.0	0.112	0.0
NC	Charlotte-Gastonia NA Area	Moderate	0.119	0.7	0.137	2.1
NC	Greensboro-Winston-Salem-High Point	Attainment	0.113	0.3	0.121	1.0
NC	Raleigh-Durham NA Area	Attainment	0.118	0.7	0.128	2.1
OH-KY	Cincinnati-Hamilton NA Area	Moderate	0.125	1.3	0.121	1.0
SC	Cherokee Co NA Area	Attainment	0.105	0.3	0.108	0.0
TN	Knoxville NA Area	Attainment	0.118	0.0	0.120	0.0
TN	Memphis NA Area	Marginal	0.115	0.3	0.119	1.0
TN	Nashville NA Area	Moderate	0.124	1.1	0.126	2.1

Region V

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update A.Q. Value	1991-93 Update Average Est. Exc.	1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
IL-IN	Chicago-Gary-Lake County NA Area	Severe 17	0.145	4.7 (#5)	0.125	2.4
IL	Jersey Co NA Area	Marginal	0.112	0.7	0.127	2.0
IN	Evansville NA Area	Marginal	0.110	0.0	0.110	0.0
IN	Indianapolis NA Area	Marginal	0.104	0.0	0.104	0.0
IN	South Bend-Elkhart NA Area	Marginal	0.103	0.0	0.096	0.0
MI	Detroit-Ann Arbor NA Area	Moderate	0.122	1.0	0.122	1.0
MI	Grands Rapids NA Area	Moderate	0.146	3.4 (#8)	0.094	1.0
MI	Muskegon NA Area	Moderate	0.141	2.3	0.104	1.0
OH	Canton NA Area	Marginal	0.109	0.3	0.109	0.0
OH-KY	Cincinnati-Hamilton NA Area	Moderate	0.125	1.3	0.121	1.0
OH	Cleveland-Akron-Lorain NA Area	Moderate	0.125	1.7 (#9)	0.117	0.0
OH	Columbus NA Area	Marginal	0.118	0.3	0.105	0.0
OH	Dayton-Springfield NA Area	Moderate	0.112	0.0	0.120	1.0
OH	Toledo NA Area	Moderate	0.120	0.3	0.121	1.0
OH-PA	Youngstown-Warren-Sharon NA Area	Marginal	0.113	0.3	0.120	1.0
WI	Door Co NA Area	Marginal	0.125	1.6	0.098	0.0
WI	Kewaunee Co NA Area	Moderate	0.107	0.8	0.095	0.0
WI	Manitowoc Co NA Area	Moderate	0.132	2.0	0.095	0.0
WI	Milwaukee-Racine NA Area	Severe 17	0.148	3.9	0.125	2.4
WI	Sheboygan NA Area	Moderate	0.139	2.6 (#11)	0.095	0.0
WI	Walworth Co NA Area	Marginal	0.120	0.3	0.093	0.0

Region VI

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update A.Q. Value	1991-93 Update Average Est. Exc.	1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
LA	Baton Rouge NA Area	Serious	0.135	1.8	0.127	3.0
LA	Lake Charles NA Area	Marginal	0.132	1.3 (#6)	0.108	0.0
TX	Beaumont-Port Arthur NA Area	Serious	0.130	2.7	0.122	0.0
TX	Dallas-Fort Worth NA Area	Moderate	0.141	2.0	0.140	2.3
TX	El Paso NA Area	Serious	0.136	3.7	0.135	4.1
TX	Houston-Galveston-Brazoria NA	Severe 17	0.200	6.3	0.197	10.4

Region VII

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update A.Q. Value	1991-93 Update Average Est. Exc.	1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
MO-KS	Kansas City NA Area	Attainment	0.114	0.3	0.114	1.0
MO-IL	St. Louis NA Area	Moderate	0.132	1.7	0.126	2.1

Region VIII

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update A.Q. Value	1991-93 Update Average Est. Exc.	1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
UT	Salt Lake City-Ogden NA Area	Moderate	0.106	0.0	0.104	0.0

Region IX

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update A.Q. Value	1991-93 Update Average Est. Exc.	1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
AZ	Phoenix	Moderate	0.147	4.0 (#4)	0.126	2.0
CA	Los Angeles South Coast Air Basin	Extreme	0.300	104.3	0.250	97.6
CA	Monterey Bay Unified NA Area	Moderate	0.108	0.4	0.104	0.0
CA	Sacramento Metro NA Area	Serious	0.150	9.7	0.150	3.6
CA	San Diego NA Area	Severe 15	0.150	11.8	0.160	4.0
CA	San Francisco-Bay NA Area	Moderate	0.120	0.7	0.130	2.0
CA	San Joaquin Valley NA Area	Serious	0.160	18.9	0.160	27.5
CA	Santa Barbara-Santa Maria-Lompoc	Moderate	0.123	1.0	0.114	0.0
CA	Southeast Desert Modified AQMD	Severe 17	0.200	59.3	0.180	72.6
CA	Ventura Co NA Area	Severe 15	0.150	15.9	0.144	9.0
NV	Reno	Marginal	0.089	0.0	0.089	0.0

Region X

Table 1. Ozone Nonattainment Areas - Air Quality Update, 1991-93

State	Nonattainment Area Name	Clean Air Act Classification	1991-93 Update A.Q. Value	1991-93 Update Average Est. Exc.	1993 2nd Daily Max 1-hr	1993 Estimated Exceedances
OR	Portland-Vancouver AQMA NA Area	Marginal	0.108	0.7	0.103	0.0
WA	Seattle - Tacoma NA Area	Marginal	0.105	0.0	0.100	0.0

SOURCE: EPA's air quality data system, the Aerometric Information Retrieval System (AIRS), with supplemental data from EPA Regional Offices.

NOTES:

1. Designations and classifications for ozone nonattainment areas as published in the Federal Register, 40 CFR Part 81. *Unclassified and transitional nonattainment areas are not included in this listing.*

2. The updated air quality value is estimated for the 1991-93 period using EPA guidance for calculating design values (Laxton Memorandum, June 18, 1990). Generally, the fourth highest monitored value with 3 complete years of data is selected as the updated air quality value because the standard allows one exceedance for each year. It is important to note that the 1990 Clean Air Act Amendments required that O_3 nonattainment areas be classified on the basis of the design value at the time the Amendments were passed, generally the 1987-89 period was used.

3. The National Ambient Air Quality standard for ozone is 0.12 parts per million (ppm) daily maximum 1-hour average not to be exceeded more than once per year on average. The average estimated number of exceedances column shows the number of days the 0.12 ppm standard was exceeded on average at the site recording the highest updated air quality value. This is done after adjustment for incomplete, or missing days, during the 3-year period, 1991-93. The last two columns contain data from the site recording the highest second daily maximum 1-hour concentration in 1993. The last column shows the estimated exceedances for 1993 at the site recording the highest second maximum 1-hour concentration listed in the previous column.

4. Special purpose monitoring (SPM) operating during the ozone monitoring season.

5. The nonattainment/updated air quality value site for the Chicago NA Area is in Kenosha County, WI.

6. The Regional Office is reviewing the status of the area based on data through 1994.

7. Incomplete data reported in 1991.

8. Calculation of the updated air quality value and estimated exceedances adjusted to account for start-up of a LMOS Study site with data only in 1991.

9. Data from a monitoring site located at the water treatment plant not used due to localized interference.

10. The site was located atop Whitetop Mountain, VA as part of the Mountain Cloud Study. Site elevation is 5520 feet. No data reported after 1988. This is a rural transport area. The nonattainment area is that portion of Whitetop Mountain above 4500 feet elevation.

11. Calculation of estimated exceedances adjusted for Wisconsin ozone season not yet reflected in AIRS.

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APPENDIX G

LISTING OF MUNICIPAL SOLID WASTE LANDFILL ORGANIZATIONS AND RELATED SERVICE PROVIDERS

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Listing of Municipal Solid Waste Landfill Organizations and Related Service Providers

Solid Waste Association of North America (SWANA)
P.O. Box 7219
Silver Spring, MD 20910-7219
Contact: Michael Ohlsen
Phone: (301) 585-2989
Fax: (301) 585-7068

Environmental Industry Associations (EIA)/ National Solid Wastes Management Association (NSWMA)
4301 Connecticut Avenue, NW
Suite 300
Washington, DC 20008
Contact: Ed Repa
Phone: (202) 244-4700
Fax: (202) 966-4818

Association of State and Territorial Solid Waste Management Officials (ASTSWMO)
Hall of States
Suite 343
444 North Capitol Street, NW
Washington, DC 20001
Phone: (202) 624-5828
Fax: (202) 624-7875

National Business Industries Association
122 C Street, NW
Fourth Floor
Washington, DC 20001
Phone: (202) 383-2540
Fax: (202) 383-2670

Department of Energy Regional Biomass Energy Program
Office of National Programs
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, D.C. 20585
Contact: N. Michael Voorhies, National Coordinator
Phone: (202) 586-9104

American Public Works Association
1301 Pennsylvania Avenue, NW
Suite 501
Washington, DC 20004
Contact: Sarah Layton
Phone: (202) 347-0612
Fax: (202) 737-9153

<u>Regional Biomass Energy Programs:</u>

Northeast Region
Richard Handley, Program Manager
CONEG Policy Research Center, Inc.
400 North Capitol Street, NW
Suite 382
Washington, DC 20001
Phone: (202) 624-8454
Fax: (202) 624-8463

Northwest Region
Jeff James, Program Manager
U.S. Department of Energy
Seattle Regional Support Office
905 NE 11th Avenue
Portland, OR 97232
Phone: (503) 230-3449
Fax: (503) 230-4973

Regional Biomass Energy Programs (continued):

Great Lakes Region
Frederick J. Kuzel
Council of Great Lakes Governors
35 East Wacker Drive #1850
Chicago, IL 60601
Phone: (312) 407-0177
Fax: (312) 407-0038

Southeast Region
Philip Badger, Program Manager
Tennessee Valley Authority
435 Chemical Engineering Building
Muscle Shoals, AL 35660
Phone: (205) 386-3086
Fax: (205) 386-2963

Western Region
Dave Swanson
Western Area Power Authority
1627 Cole Boulevard
P.O. Box 3402
Golden, CO 80401
Phone: (303) 231-1615
Fax: (303) 231-1632

APPENDIX H

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APPENDIX I

ACID RAIN FACT SHEET

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United States
Environmental Protection
Agency

Air and
Radiation
(6204-J)

EPA 430-K-94-014
November 1994

Landfill Methane and Clean Air Act Opportunities

Incentives from the Acid Rain Program

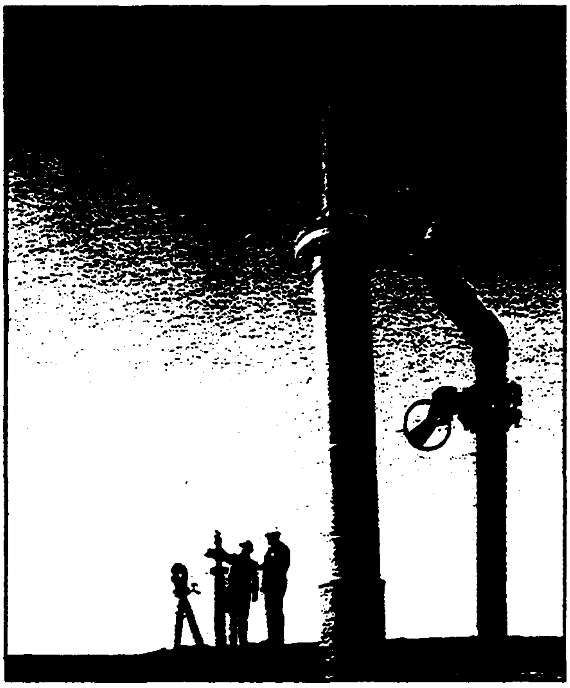

Photo courtesy of New England Electric System

The environmental benefits of generating electricity from landfill methane now have an added, quantifiable value. Through an innovative system of tradeable emission allowances, Title IV of the Clean Air Act has increased the value of electricity generated from landfill methane.

ACID RAIN PROGRAM

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Methane gas emissions from our country's growing landfill sites are a serious threat to greenhouse gas stabilization. Capturing methane from landfill sites for electrical generation serves both economic and environmental goals. Landfill methane is already a cost-effective energy resource in many areas of the country. The Clean Air Act incentives will further enhance the cost-effectiveness of landfill methane energy projects.

The Clean Air Act Incentives

The 1990 Clean Air Act Amendments call for a 10 million ton annual reduction in national SO_2 emissions from 1980 levels. This program creates a new tradeable commodity, the SO_2 emission allowance. Each allowance represents an authorization to emit one ton of SO_2 (i.e., a unit that emits 5,000 tons of SO_2 must hold at least 5,000 allowances that are usable that year). By avoiding the emission of SO_2 with landfill methane systems, utilities will both earn and save tradeable emission allowances. And these emission allowances have a real market value.

To promote pollution prevention, Title IV of the Clean Air Act includes two incentives for energy efficiency and renewable energy. These incentives are:

1. Avoided emissions

2. Conservation and Renewable Energy Reserve

Avoided emissions is perhaps the most lucrative of the incentives; each ton of SO_2 avoided through the generation of electricity from landfill methane saves one emission allowance. Allowances are saved at the utility's own rate of emissions. The avoided emissions incentive is automatic; there are no application or verification requirements.

The Sonoma County, California landfill gas-to-energy facility. Photo courtesy of Landfill Energy Systems.

The Conservation and Renewable Energy Reserve is a special bonus pool of 300,000 allowances set aside to reward new initiatives in technologies such as landfill methane. For every 500 MWh of electricity generated through landfill methane systems, a utility earns one allowance from the Reserve.

For more information on these incentives, see *Energy Efficiency and Renewable Energy: Opportunities from Title IV of the Clean Air Act.*[1]

1. US EPA, *Energy Efficiency and Renewable Energy: Opportunities from Title IV of the Clean Air Act*, Document no. EPA 430-R-94-001, February 1994. To obtain a copy, contact the Acid Rain Hotline at (202) 233-9620.

Valuing the Incentives

In general, the value of the Clean Air Act incentives will be the number of allowances earned or saved by the landfill methane installation multiplied by the market price of an SO_2 emission allowance. The hypothetical example below illustrates the potential savings from the Clean Air Act incentives.[2]

The market for tradeable emission allowances is continuing to evolve. A recent report issued by the Electric Power Research Institute (EPRI) indicates that prices could rise from $250 per allowance in 1995 to $480 per allowance in 2007.[3] Price signals are also being provided by private trades and trading exchanges.

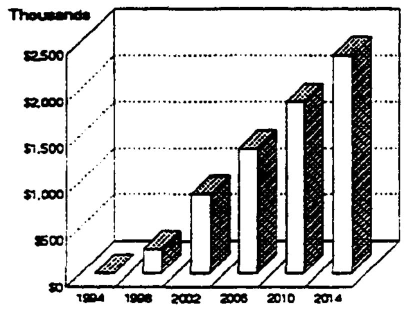
Example

In 1994, a utility installs 7 MW of capacity from landfill methane sites. The utility will enter the Acid Rain Program in the year 2000, and thus is eligible to earn Reserve allowances until 2000. Assuming a typical capacity factor of 0.85, the value of the Reserve allowances is calculated as follows:

7 MW x 8,760 hours/yr x 0.85 = 52,122 MWh/yr
52,122 MWh/yr ÷ 500 MWh/allowance = 104 allow./yr
$250/allowance x 104 allowances/yr = $26,000/yr

Thus, for the six years from 1994 through 1999, the utility could earn $156,000 from the Reserve alone. However, landfill methane will continue to add value in the year 2000 and beyond through the avoided emissions incentive. And the benefits from avoided emissions will be even greater than those from the Reserve.

Cumulative Value of the SO_2 Incentives



Assuming the utility's marginal rate of SO_2 emissions is 1.2 lbs/mmBtu (the emission limit for the Acid Rain Program) and a typical heat rate of 10,000 Btu/kWh, the value of avoided emissions in the year 2000 is:

1.2 lbs/mmBtu x 10,000 Btu/kWh x mmBtu/1,000,000 Btu = 0.012 lbs/kWh
52,122,000 kWh x 0.012 lbs/kWh x 1 ton/2000 lbs = 313 tons = 313 allowances
313 allowances x $340/allowance = $106,420

Assuming a 20 year project life and a 6% discount factor, the net present value of the Clean Air Act incentives for this landfill methane project is $980,000.

Since landfill methane is a local resource, transmission losses are reduced and thus further improve the project's cost-effectiveness.

2. For a more detailed explanation of the calculations in this example, contact the Acid Rain Hotline at (202) 233-9620 and ask for the *Landfill Methane Example.*

3. EPRI, *Integrated Analysis of Fuel, Technology and Emission Allowance Markets: Electric Utility Responses to the Clean Air Act Amendments of 1990,* Report no. TR-102510, August 1993, p. 1-20.

	1995	2000	2003	2007
Price ($/ton)	$250	$340	$400	$480

Utility Allies: Tapping the Potential of Landfill Methane

By purchasing electricity generated from landfill gas, utilities gain a clean, renewable energy source, produce valuable reductions in local air pollutants and greenhouse gases, and build a more diverse and local resource base. To mobilize the use of landfill gas as an energy resource, EPA has created the Landfill Methane Outreach Program.

To become a Utility Ally in this program, a utility agrees to take advantage of the best opportunities for obtaining power from landfill gas. In turn, EPA recognizes and publicizes the utility's efforts and can assist in the evaluation and development of projects. The result is a win for the utility and its customers, and a win for the environment and the economy.

LANDFILL METHANE OUTREACH PROGRAM

EPA estimates that over 700 landfills across the US could install economically viable landfill gas energy recovery systems, yet only about 115 facilities are in place. The EPA Landfill Methane Outreach Program is working to overcome the informational, regulatory, and other barriers that prevent these otherwise economical projects from going forward.

For more information on how your utility can become a Utility Ally, please contact EPA's Landfill Methane Program at (202) 233-9042.

Complying Cost-Effectively

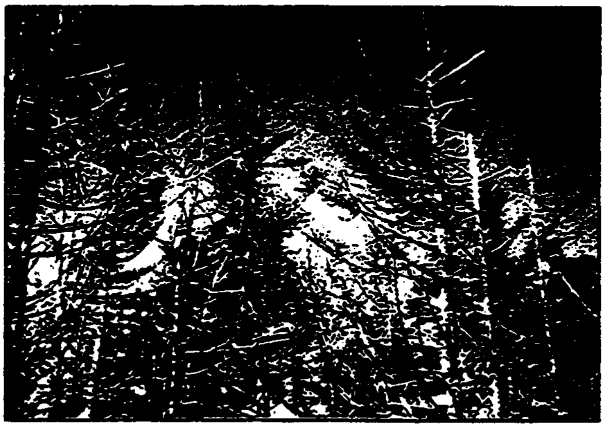
Landfill methane resources can be cost-effective components to an integrated compliance strategy by:

- Complementing or offsetting the use of other compliance strategies such as fuel-switching;
- Delaying or eliminating the need for expensive alternative strategies such as scrubbing;
- Helping to avoid the noncompliance penalty of $2,000 per ton of SO_2; and
- Increasing revenues through the sale of extra allowances.

The extent to which the Clean Air Act incentives affect the financial outlook of landfill methane systems will depend upon each utility's own circumstances. Utilities that currently emit high levels of SO_2 can benefit significantly from the incentives. However, even utilities already in compliance can benefit from the revenues generated from extra allowances.

Emissions from fossil fuel generation harm waters and forests, endanger animal species, accelerate the decay of buildings and monuments, and impair public health. In many sensitive lakes and streams acidification has completely eradicated fish species.

Research has pointed to the increased health risks from particulate matter, which includes sulfates and other pollutants emitted during the combustion of fossil fuels. A recent study by Harvard University's School of Public Health linked these emissions to higher mortality rates and lung dysfunction in children and other sensitive populations.[4]

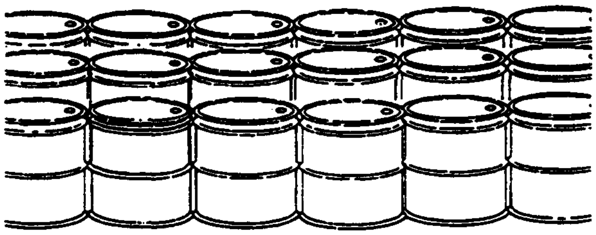


Emissions from fossil-fuel sources have damaged many forests.

Electricity generated from landfill methane helps combat not only acid rain, but other environmental harms as well, including global climate change. Landfill methane systems avoid emissions of SO_2, toxics, and particulates, as well as the production of ash and scrubber sludge.

Electricity generated from landfill methane will also help minimize emissions affecting global climate change. Not only does this resource offset emissions from fossil fuel energy generation, but it also prevents the escape of methane gas, a greenhouse gas that is over 20 times more potent than carbon dioxide. Every 10,000 kilowatt hours of electricity generated from landfill methane is equivalent to:[5]

Planting 23,680 Trees per Year, or



Eliminating 360 Barrels of Crude Oil

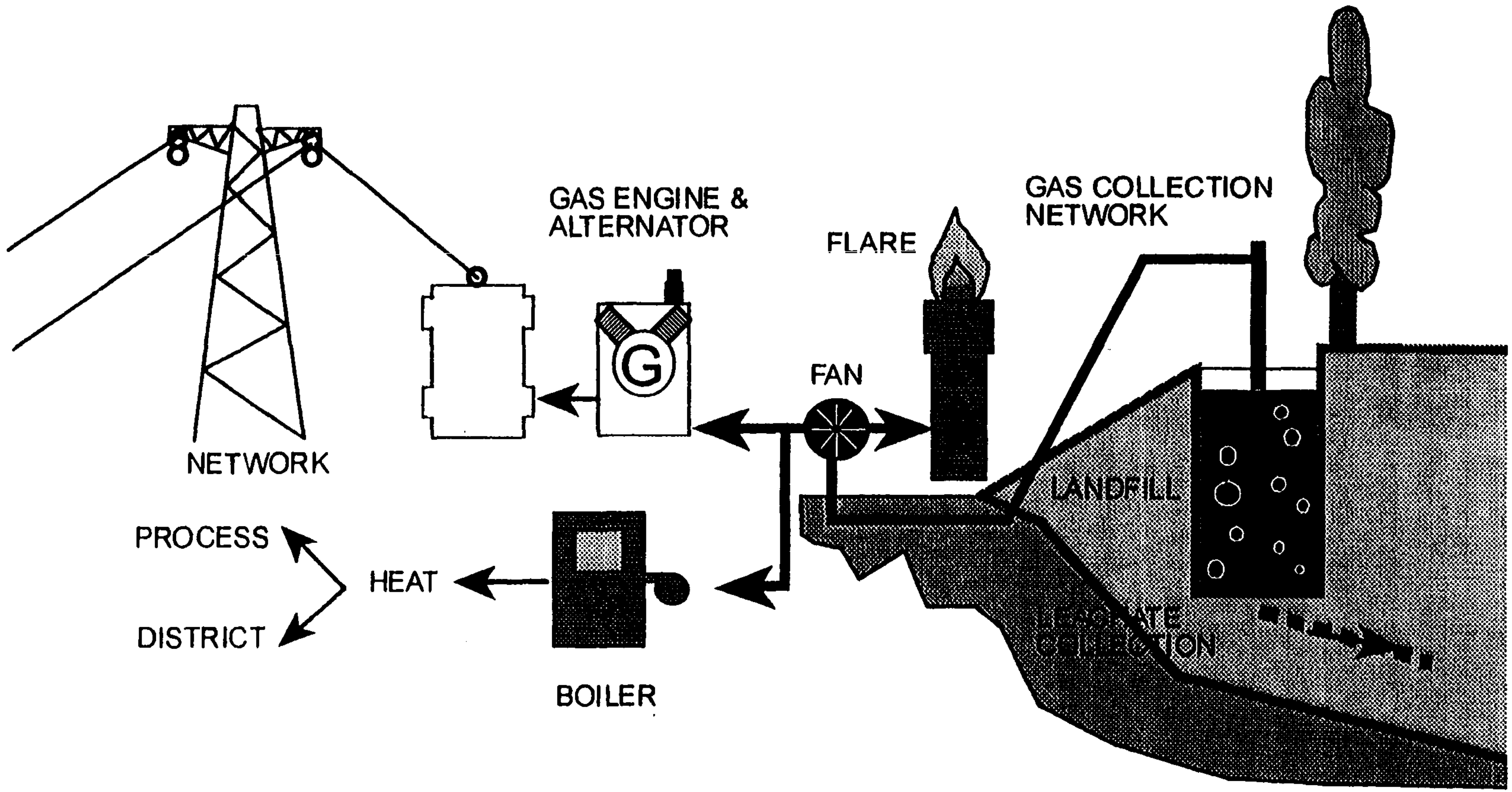
Landfill methane systems can be cost-effective solutions for simultaneously eliminating multiple pollutants. Rather than installing costly controls for each pollutant, landfill methane technology can be a solution for many pollutants. Landfill methane systems also provide insurance against the risk of future environmental regulations, including regulations on greenhouse gas emissions.

The real, quantifiable value of the Clean Air Act incentives can maximize a utility's overall cost-effectiveness in serving its customers and protecting the environment.

4. Dockery, Douglas W., et al., *An Association between Air Pollution and Mortality in Six US Cities*, The New England Journal of Medicine, vol. 329, no. 24, December 9, 1993, p. 1753-9.

5. Based on the 1990 average CO_2 emission rate for US utility generation.

Landfill Methane Recovery Process

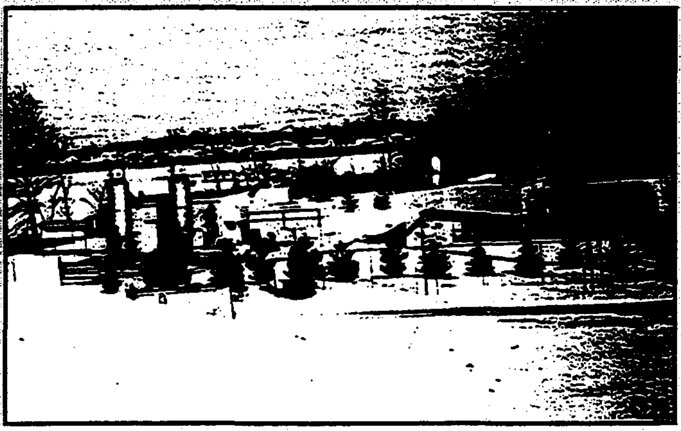


Landfill gas is generated naturally through the bacterial decomposition of organic matter deposited in a sanitary landfill. Gas collection systems pull the gas from a series of wells to a central processing facility. Landfill gas is typically a medium Btu gas that has a number of energy applications. The most prevalent use is production of electricity for sale to the local utility. The gas may also be employed directly for use as boiler fuel and industrial process heat or converted for use as compressed natural gas for vehicle fuel.

Utility Profile: Detroit Edison Company

As the landfill gas recovery industry evolved in the 1980s, Detroit Edison became active in developing Michigan's first landfill gas-fired combustion turbine generating station. The 6.6-megawatt facility has safely and reliably operated at more than 85 percent capacity since achieving commercial operation in 1988.

Sited on a landfill owned by the City of Riverview, 20 miles south of Detroit, the small power production facility uses enough methane gas to generate electricity for about 6,000 homes. More than 100 gas wells on the 150-acre site collect about 4.3-million cubic feet of landfill gas daily to generate the power, which is sold to Detroit Edison.



Riverview, Michigan landfill gas-to-energy facility

While the project's 225,000 megawatt-hours of electricity is a small portion of Detroit Edison's overall power production, the environmental significance is impressive. By capturing more than 8 million cubic feet of landfill gas, this project has prevented more than 1,200 tons of sulfur dioxide emissions which would have been produced by fossil-fueled power generation. Each day the project directly destroys more than 2 million cubic feet of methane, a potent greenhouse gas.

Detroit Edison's involvement with 120-acre Sonoma Central landfill in California is relatively new. Through a subsidiary, landfill gas is collected, cleaned, compressed and delivered as fuel to a plant producing 3.2 megawatts. Sonoma County, owner of the facility, has been selling the electricity since May 1993. The facility uses about 1,200 cubic feet per minute of landfill gas to produce its power.

The Riverview and Sonoma facilities are licensed to operate well into the 21st century. Their success has prompted Detroit Edison to pursue similar ventures in Florida, Illinois, Texas, Ohio, and elsewhere in Michigan.

For More Information

Write to:

US Environmental Protection Agency
Acid Rain Division (6204J)
Energy Efficiency and Renewable Energy
Section
401 M Street, SW
Washington, DC 20460

If you have further questions or would like to receive any other publications, please call the Acid Rain Hotline at (202) 233-9620. An Energy Efficiency and Renewable Energy staff member will return your call within 24 hours.

APPENDIX J

GLOSSARY OF TERMS

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Glossary of Terms

AFFECTED LANDFILL: Landfills that meet criteria set by the EPA under authority of Title I of the Clean Air Act for capacity, age, and emission rates; affected landfills are required to collect and combust their landfill gas

ATTAINMENT AREA: A geographic region that meets National Ambient Air Quality Standards (NAAQS) for specific air pollutants

AVOIDED COST: The cost a utility would incur to generate the next increment of electric capacity using its own resources; many landfill gas projects' buyback rates are based on avoided costs

BASELOAD: A term referring to the energy use of a facility that has a consistent, year-round need for energy; baseload can also refer to the minimum amount of electricity supplied to a facility on a continuous basis

BEST AVAILABLE CONTROL TECHNOLOGY (BACT): The most stringent technology available for controlling emissions; major sources are required to use BACT, unless it can be demonstrated that it is not feasible due to energy, environmental, or economic reasons

BUYBACK RATE: The price a utility will pay a third party supplier for electricity or gas

CAPACITY FACTOR: The ratio of the energy produced by a piece of equipment during a given time period to the energy the unit could have produced if it had been operating at its full rated capacity

CAPACITY PRICE: The fixed price in $/kW a utility pays a third party supplier for a guaranteed availability of generating capacity; capacity price is based on the capital costs of a generating unit

CAPITAL CHARGE RATE: A number used to convert the installed cost of a power project into a levelized capital cost that can be charged to the project in each year of the project life

CAPITAL COST: The total installed cost of equipment, emissions control, interconnections, gas compression, engineering, soft costs, etc. for landfill gas projects

COGENERATION: The consecutive generation of useful thermal energy and electric energy from the same fuel source

COMBINED-CYCLE: Technology in which waste heat from a gas turbine is used to produce steam in a waste-heat boiler; the steam is then used to generate electricity in a steam turbine/generator

CONDENSATE: Liquid formed when warm landfill gas cools as it travels through the collection system

COST OF CAPITAL: The cost to a company of acquiring funds to finance the company's capital investments and operations

DEBT COVERAGE RATIO: Ratio of operating income to debt service requirement, usually calculated on an annual basis

DEBT SERVICE REQUIREMENT: Monthly requirement to meet the principal and interest amounts of a loan

DISPLACEMENT SAVINGS: Savings realized by displacing purchases of natural gas or electricity from a local utility by using landfill gas

EPC FIRM: A company that provides engineering, procurement, and construction services

FLARE: A device used to combust excess landfill gas that is not used in energy recovery; flares may be open or enclosed

GREENHOUSE GAS: A gas, such as carbon dioxide or methane, which contributes to global warming

GROSS POWER GENERATION POTENTIAL: The installed power generation capacity that landfill gas flows can support

HEAT RATE: A measure of generating unit thermal efficiency, expressed in units of Btu/kWh

LOWEST ACHIEVABLE EMISSIONS RATE (LAER): The most stringent technology available for controlling emissions; major sources are required to use LAER (cost is not a consideration in determining the LAER technology)

MAJOR SOURCE: New emissions sources or modifications to existing emissions sources that exceed NAAQS emission levels

METHANE (CH_4): The major component of natural gas and landfill gas; produced in landfills when organic matter in waste decomposes

METRIC TON: Measurement of mass; one metric ton equals one megagram (Mg)

MINOR SOURCE: New emissions sources or modifications to existing emission sources that do not exceed NAAQS emission levels

NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS): Air quality standards, established by the Clean Air Act, for six criteria pollutants

NET PRESENT VALUE (NPV): The amount of money, that if invested today at a given rate of return, would be equivalent to a fixed amount to be received at a specified future time

NEW SOURCE REVIEW (NSR): Process by which an air quality regulatory agency evaluates an application for a permit to construct a new generating facility

NONATTAINMENT AREA: A geographic region designated by the EPA that exceeds NAAQS for one or more criteria pollutants

NON-METHANE ORGANIC COMPOUNDS (NMOCs): Compounds found in landfill gas which affect human health and vegetation; NMOCs include several compounds that are known carcinogens to humans

PARASITIC LOAD: The electric load required to run generation equipment; contributes to the difference between gross and net output

PREVENTION OF SIGNIFICANT DETERIORATION (PSD): Regulations designed to limit the increase of criteria air pollutants in attainment areas

PRO FORMA: A computer model of project cash flows over the life of the project, usually containing several standard items

PROJECT FINANCE: A method for obtaining commercial debt financing for the construction of a facility where lenders look to the creditworthiness of the facility to ensure debt repayment, rather than to the assets of the project developer

PUMP TEST: A procedure used to determine the gas generation rate of a landfill; it involves drilling test wells and installing pressure probes

PUBLIC UTILITIES REGULATORY POLICIES ACT (PURPA): Act that requires utilities to purchase the electric output from QFs at the utility's avoided cost

QUALIFYING FACILITY (QF): A cogenerator or small power producer, as defined by PURPA, that is entitled to special regulatory treatment; utilities are required to purchase the electrical output from QFs at the utility's avoided cost

RATE OF RETURN (ROR) ON EQUITY: Financial measurement used to judge the percent of return on equity capital used in business

RENEWABLE ENERGY PRODUCTION INCENTIVE (REPI): Incentive established by the Energy Policy Act, that is available to renewable energy power projects owned by a state or local government or nonprofit electric cooperative

REQUEST FOR PROPOSALS (RFP): A solicitation by a utility for project proposals

ROYALTIES: Compensation given to a landfill owner for gas rights

SENIOR DEBT LENDER: Institution or person who lends money with the intention that the debt will be repaid before project earnings get distributed to equity investors

SOFT COSTS: Transaction and legal costs, escalation during construction, interest during construction, and contingency costs associated with a project

STANDARD OFFER: A power purchase agreement, sanctioned by the state utility commission, that is typically based on avoided costs

SUBORDINATED DEBT: Money that is repaid after any senior debt lenders are paid and before equity investors are paid

VOLATILE ORGANIC CHEMICALS (VOCs): Chemicals found in landfill gas that are contributors to smog

WHEELING: The transmission of electricity owned by one entity using the facilities owned by another entity (usually a utility)

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