User's Manual

Landfill Methane Outreach Program (LMOP)
U.S. Environmental Protection Agency
Washington, DC

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Background on the Model

LFGcost was initially developed in 2002 to help stakeholders estimate the costs of an LFG energy project. Since then, the U.S. EPA Landfill Methane Outreach Program (LMOP) has routinely updated the tool to reflect changes in the LFG energy industry. In 2015, LMOP undertook a peer review of LFGcost-Web, Version 3.0. For more information on the peer review, see the Emission Guidelines and Compliance Times for Municipal Solid Waste Landfills rule docket (Docket ID# EPA-HQ-OAR-2014-0451-0210). Based on the results of the peer review as well as other updates, LMOP revised certain elements of the model, replacing it with LFGcost-Web, Version 3.1 in 2016. In May 2017 and August 2019, LMOP released minor updates in Versions 3.2 and 3.3, respectively. LFGcost-Web, Version 3.4, was released in October 2020 and included a significant update to the underlying capital and operation and maintenance (O&M) expenses for large-scale renewable natural gas (RNG) pipeline-injection projects. LFGcost-Web, Version 3.5, was released in March 2021 and included a new economic impact tool which can be used to calculate the economic benefits provided by RNG projects.

LFGcost-Web, Version 3.6, was released in September 2023 and includes updated product prices, escalation rates, and other economic factors based on information from the most recent iteration of the *Annual Energy Outlook* and other information sources.

The model and user's manual were prepared for LMOP by Eastern Research Group, Inc. (ERG) with assistance and data contributions for the model from Tetra Tech SWE; Smith Gardner, Inc.; Energy Vision; Enerdyne Power Systems, Inc.; The Hunter Group LLC; and CPL Systems, Inc.

Introduction

The Landfill Gas Energy Cost Model, LFGcost-Web, is a software tool developed for LMOP to conduct initial economic analyses of prospective landfill gas (LFG) energy recovery projects in the United States. **Analyses performed using LFGcost-Web are considered estimates and should be used for guidance only. A detailed final feasibility assessment should be conducted by qualified LFG professionals prior to preparing a system design, initiating construction, purchasing materials or entering into agreements to provide or purchase energy from an LFG energy project.**

The software was created in Microsoft® Excel to make the computations transparent and to allow for the model to be efficiently updated as the economics of LFG energy projects mature. This document describes how to use the LFGcost-Web spreadsheet tool and presents the technical basis underlying the software methodology.

The various LFG energy project types that can be analyzed in LFGcost-Web include:

- New LFG collection and flaring systems (not expansion of existing systems);
- Direct-use (boiler, greenhouse, etc.);
- Boiler retrofit;
- RNG processing plant;
- Onsite compressed natural gas (CNG) production and fueling station;
- Seven different electricity generation project types:
    - Standard turbine-generator sets;
    - Standard reciprocating engine-generator sets;
    - Microturbine-generator sets;
    - Small reciprocating engine-generator sets;
    - Combined heat and power (CHP) reciprocating engine-generator sets;
    - CHP turbine-generator sets; and
    - CHP microturbine-generator sets.

LFGcost-Web is an LFG energy project cost estimating tool developed for EPA's LMOP. LFGcost-Web estimates LFG generation rates using a first-order decay equation. This equation is used to estimate generation potential but cannot be considered an absolute predictor of the rate of LFG generation. Variations in the rate and types of incoming waste, site operating conditions and moisture and temperature conditions may provide substantial variations in the actual rates of generation.

The default inputs and costs estimated by LFGcost-Web are based on typical project designs and for typical landfill situations. While the model allows a user to adjust certain inputs to site- and project-specific conditions, the equations within the model are locked to maintain the integrity of the model. The model attempts to include all equipment, site work, permits, operating activities and maintenance that would normally be required for constructing and operating a typical project. However, individual landfills may require unique design modifications which would add to the cost estimated by LFGcost-Web.

Using LFGcost-Web

Summary of Revisions

LFGcost-Web, Version 3.6, replaces Version 3.5. Significant revisions between Version 3.6 and Version 3.5 of LFGcost-Web included:

- Updates to product prices, escalation rates, and other economic factors based on information from the *Annual Energy Outlook 2023* and other information sources.
- Update of the global warming potential (GWP) of methane from 25 to 28.

General Instructions and Guidelines

The first worksheet within LFGcost-Web (see INST worksheet) provides important instructions on the proper use of LFGcost-Web. These instructions include the size ranges over which LFGcost-Web is expected to be most accurate for a given project type. Within these size ranges LFGcost-Web is estimated to have an accuracy of ± 30 to 50 percent. Using LFGcost-Web to evaluate projects outside of these recommended ranges will likely provide cost estimates with a greater uncertainty. The INST worksheet also provides definitions of input and output parameters, outlines the organization of LFGcost-Web and summarizes important notes described below regarding the model and its functionality.

Detailed information about running the model for unique project scenarios is contained in Appendices C, D and E. Appendix C provides guidance for evaluating projects with multiple equipment and/or start dates, Appendix D outlines the suggested inputs for local government-owned projects and Appendix E explains how to set up and interpret results for boiler retrofit projects.

Inputs

The second worksheet of LFGcost-Web (see INP-OUT worksheet) is where users enter the required input data for evaluating an LFG energy project. In this worksheet, the ***Required User Inputs*** table allows users to enter the minimum input parameters required for conducting an economic analysis. The ***Optional User Inputs*** table gives users the option to adjust the default input parameters used by LFGcost-Web. If these optional input parameters are not known for the project being evaluated, the default parameters should provide a reasonable economic evaluation of the project.

Outputs

The INP-OUT worksheet summarizes the results of the economic and environmental analysis performed by LFGcost-Web in the ***Outputs*** table. This table has been arranged so users of LFGcost-Web are able to change the project design and immediately see the resulting change in economic analysis, without having to switch to another worksheet in LFGcost-Web. Most users of LFGcost-Web will not need to look at other worksheets in LFGcost-Web when conducting a routine economic analysis.

Calculators

LFGcost-Web provides two calculators to assist model users. The ***Waste Acceptance Rate Calculator*** in the WASTE worksheet calculates the average annual waste acceptance rate based on the amount of waste-in-place and the year representing the time required to accumulate this waste. Model users who do not know the average annual waste acceptance rate for a particular landfill can use this calculator to estimate this rate.

The ***Financial Goals Calculator***, located below the ***Outputs*** table in the INP-OUT worksheet, calculates the initial product price that would be required for the project to achieve its financial goals. It is assumed that financial goals are achieved when the internal rate of return (IRR) equals the discount rate and the net present value is equal to $0. If a given economic analysis does not achieve its financial goals or greatly exceeds the goals, model users can use this calculator to determine the initial product price that is required to pay back the investment within the lifetime of the project.

Model users **must** select "Enable Macros" or "Enable Content" when prompted (immediately after opening the file) to allow the LFGcost-Web software to use the embedded macros that control the operation of the ***Financial Goals Calculator***. Enabling macros is discussed further in the "Software Requirements" section below. The ***Financial Goals Calculator*** can be used **ONLY** when macros are enabled and the ***Solver Add-in*** has been installed and loaded within Microsoft® Excel. Please see the instructions below the ***Calculate Initial Product Price*** button in the INP-OUT worksheet to load the ***Solver Add-in***. **This functionality is not compatible with Mac computers.**

Summary Reports

The first summary report (see REPORT worksheet) presents input, output and curve information similar to data found in the INP-OUT and CURVE worksheets. The printout will be labeled with the landfill name or identifier that has been entered at the top of the INP-OUT worksheet as well as the file name and current date. The appropriate initial product price needed to achieve financial goals **must** be determined for each LFG energy project scenario using the ***Financial Goals Calculator*** in order for the correct financial goal prices to appear in the report.

The second summary report (see RPT-CASHFLOW worksheet) presents a detailed summary of the project cash flow analysis using data similar to data found in the ECN worksheet. Given the detailed nature of this spreadsheet, it may be appropriate to include only for certain scenarios.

The third summary report (see ECON-BEN SUMMARY worksheet) presents the regional economic benefits and job creation estimates for the following three project types: electricity generation with standard reciprocating engines, direct-use and injection of RNG into the pipeline.

An Adobe Portable Document Format (PDF) of the summary reports can be created from the REPORT, RPT-CASHFLOW and/or ECON-BEN SUMMARY worksheets in order to save or distribute read-only electronic copies. In order to create a PDF of the reports users must have a printer driver installed on their computer that has the capability to convert files to this format (for example, PDF995 or Adobe Acrobat). With this PDF printer driver installed, users can follow the steps listed below to create a PDF of the summary reports.

1. Select the worksheet tab(s) you are interested in printing.
2. Select *Print* from the menu.

3. Select the PDF printer driver (e.g., PDF995) from the *Printer* drop-down menu and click OK.
4. Once the PDF dialog box appears in a new window, users can preview the report and save it to a file location of their choice. If using Adobe Acrobat, users can also specify which worksheets to include in the .pdf file.

More information about downloading and purchasing PDF printer drivers can be obtained at http://www.pdf995.com/ or https://www.adobe.com.

Software Requirements

LFGcost-Web has been specified as a "Read-Only" file. The "Read-Only" restriction is intended to protect the original file from being accidentally over-written by users. You need to save a copy of the LFGcost-Web file under a new file name when running each economic analysis.

The LFGcost-Web model was created in Microsoft® Excel and must be operated in a Microsoft® Excel 2007, 2010, 2013, 2016 or Office 365 environment. Earlier versions of Microsoft® Excel are not able to properly run the model due to embedded macros. Several functions operate slowly when running LFGcost-Web on computers that have a processor speed of 333 MHz or less. This model was tested on a PC. **The Solver functionality does not work on a Mac.**

Model users must "Enable Macros" or "Enable Content" when prompted (immediately after opening the file) to allow the LFGcost-Web software to use the embedded macros.

Microsoft® Excel 2007, 2010, 2013, 2016 and Office 365 users must set their *Macro Security Level* to "Disable all macros with notification" (menu select *Developer…Macro Security*). [If the *Developer* menu is not displayed in Excel 2007, click the *Microsoft Office Button*, select *Excel Options* and then in the *Popular* category, under *Top options for working with Excel*, select *Show Developer tab in the Ribbon*. If the *Developer* menu is not displayed in Excel 2010, 2013, 2016, Office 365 on the *File* menu, select *Options* and then in the *Customize Ribbon* category, under *Customize the Ribbon*, check the *Developer* box.] Then, upon opening LFGcost-Web, users must select "Enable this content" from the *Security Warning – Options…* box that appears beneath the menu.

Cost Basis

The costs and economic parameters, such as net present value (NPV), are based on actual or "nominal" rates and include the effects of inflation. For example, if a project was constructed in 2020 and began operation in 2021, then installed capital costs in the year of construction are in 2020 dollars, operating costs for the initial year of operation are in 2021 dollars and NPV at year of construction is in 2020 dollars. Within the structure of the various cost estimating worksheets in LFGcost-Web, the costs for any given year in the life of the project are presented in that specific year's dollars.

Cost Scope

The cost estimates produced by LFGcost-Web include all direct and indirect costs associated with the project. In addition to the direct costs for equipment and installation, LFGcost-Web includes indirect costs associated with:

- Engineering, design and administration;
- Site surveys and preparation;

- Permits, right-of-ways and fees; and
- Mobilization/demobilization of construction equipment.

Since these costs are estimated for an average project site in the United States, individual sites will experience variations to these costs due to unique site conditions.

Cost Uncertainty

The uncertainty in the cost estimates produced by LFGcost-Web is estimated to be ± 30 to 50 percent. As detailed in the list below, this uncertainty is a composite of uncertainties related to LFG generation rates, future economic conditions and unique site characteristics.

The uncertainty of ± 30 to 50 percent is estimated based on the following:

- Equipment used in the actual LFG energy project may need to be purchased at a larger size than what is estimated by LFGcost-Web, because the standard equipment sizes vary from one manufacturer to another. This may result in an underestimate of the actual costs.
- Unusual site conditions may limit the type of LFG energy project that could be selected or require additional site preparation and equipment. This may result in an underestimate of the actual costs.
- Environmental or permitting constraints may lead to higher costs. This can vary from additional air pollution controls to increased equipment maintenance. This may result in an underestimate of the actual costs.
- Regional construction cost differences within the United States may result in either an overestimate or an underestimate of the actual costs, depending on the region where the landfill is located.

More specifically, the uncertainty of various project components can vary based on site-specific or project-specific needs. Below is a summary of factors affecting components of gas collection and control systems, electricity-generating projects, direct-use projects and pipeline-injection RNG projects:

Gas Collection and Control System Components and Cost Factors

Component / Attribute	Key Site-Specific Factors
Gas collection wells or connectors	• Area and depth of waste • Spacing of wells or connectors
Gas piping	• LFG flow rate • Length of piping required
Condensation knockout drum	• Volume of drum required
Blower	• Size of blower required (a function of LFG flow rate)
Flare	• Type of flare (open, ground or elevated) • Size of flare (a function of LFG flow rate)
Instrumentation and control system	• Types of controls required

Electricity-Generating Project Components and Cost Factors

Component / Attribute	Key Site-Specific Factors
Engine size	• Flow rate (gas curve) • Electricity rate structures • Minimum electricity generation requirements (contract obligations)
Capacity to expand	• Maximum flow rate • LFG flow rate over time (gas curve)
Gas compression and treatment equipment	• Quality of the LFG (methane content) • Contaminants (e.g., siloxane, hydrogen sulfide)
Interconnection equipment	• Project size • Local utility requirements and policies

Direct-Use Project Components and Cost Factors

Component / Attribute	Key Site-Specific Factors
End use of the LFG	• Type of equipment (e.g., boiler, process heater, kiln furnace) • LFG flow rate over time • Requirements to modify existing equipment to use LFG
Gas compression and treatment equipment	• Quality of the LFG (methane content) • Contaminants and moisture removal requirements • Filtration requirements
Gas pipeline	• Length (distance to the end use) • Obstacles along the pipeline route • LFG flow rate
Condensate management system	• Length of the gas pipeline

Pipeline-Injection RNG Project Components and Cost Factors

Component / Attribute	Key Site-Specific Factors
Gas compression and treatment equipment	• Quality of the raw LFG (methane content) • Flow rate of raw LFG • Pipeline gas quality specifications
Gas pipeline	• Length (distance to the end use) • Obstacles along the pipeline route • Location and class designation of pipeline (local distribution, interstate) • RNG flow rate and size/type of pipe material
Pipeline interconnect	• Whether or not compression is needed for interconnection to pipeline • Utility-specific interconnection fees • Utility-specific gas quality monitoring and testing parameters and frequency • Utility-specific requirements for gas odorization

Evaluating Economic Benefits and Job Creation

LFG energy projects generate benefits for the communities and states in which they are located, as well as for the United States as a whole. These benefits include new jobs and expenditures directly impacting the local and state-wide economies as a result of the construction and operation of an LFG energy project. In addition, there are indirect economic benefits when the direct expenditures for an LFG energy project flow through the economy resulting in increased overall economic production and economic activity within the local, state and national economies.

While in the construction phase, an LFG energy project provides a one-time boost to the local and state economies whereas the O&M of the project generates ongoing economic activity throughout the lifetime of the project. The annual impacts use the estimated expenditures during the first year of the project's operation to estimate the annual economic benefits during the O&M phase.

LFGcost-Web allocates the estimated capital and O&M costs for reciprocating engine, direct-use and RNG projects to various wholesale trade and industrial manufacturing sectors in order to estimate the regional economic benefits of the project. Here, the "region" is defined to be the state where the project is constructed and so its output will include any benefit to the local and state economies resulting from LFG energy project expenditures. The cost of large or specialized components, or specialized engineering and design labor likely to be manufactured or hired outside of the state, is not included in the state-wide impacts estimates. A specific description of how project costs are allocated to each industry multiplier is presented in the BUDGET-RNG, BUDGET-DIR and BUDGET-ENG sections of this user's manual.

The model allows the user to select a specific state in the BUDGET-RNG, BUDGET-DIR and BUDGET-ENG worksheets to represent where the project is constructed. Alternatively, if you leave the state blank and want to know the general economic benefits resulting from an LFG energy project, regardless of the state, you can review the outputs provided for states representing the median (Wisconsin) and upper (Arizona) and lower (West Virginia) quartiles for both employment and economic output in the ECON-BEN SUMMARY sheet. A summary of the multipliers and how the multipliers were ranked according to their employment and economic output is shown in Appendices F and G.

The Bureau of Economic Analysis (BEA) does not endorse any resulting estimates and/or conclusions about the economic impact of a proposed change on an area.

Further Assistance

If you would like assistance using LFGcost-Web, please contact LMOP through the website at https://www.epa.gov/lmop/forms/contact-us-about-landfill-methane-outreach-program.

Analyses performed using LFGcost-Web are considered estimates and should be used for guidance only. A detailed final feasibility assessment should be conducted by qualified LFG professionals prior to preparing a system design, initiating construction, purchasing materials or entering into agreements to provide or purchase energy from an LFG energy project.

Technical Basis of LFGcost-Web

Table 1 lists the worksheets that comprise the LFGcost-Web spreadsheet model. The following sections document the design and technical basis of the contents of these worksheets.

Table 1. Worksheet Names and Functions in LFGcost-Web

Worksheet Name	Function
INST	General instructions and guidelines
INP-OUT	Required and optional user inputs and model output results
WASTE	Optional user inputs for annual waste acceptance data
REGIONAL PRICING	Regional power grid price reference
REPORT	Summary report of user inputs, model outputs and curve
RPT-CASHFLOW	Detailed summary of 15-year cash flow analysis
CURVE	Landfill gas generation, collection and utilization curve
AVOIDED CO2-ELEC	Regional power grid emission factors reference
ENV	Environmental benefits calculations
FLOW	Landfill gas generation, collection and utilization calculations
C&F	Design and costing of new collection and flaring system
DIR	Design and costing of direct-use of landfill gas
BLR	Design and costing of boiler retrofit
RNG	Design and costing of RNG processing plant
CNG	Design and costing of onsite CNG production and fueling station
TUR	Design and costing of standard turbine-generator set
ENG	Design and costing of standard reciprocating engine-generator set
MTUR	Design and costing of microturbine-generator set
SENG	Design and costing of small reciprocating engine-generator set
CHPE	Design and costing of CHP reciprocating engine-generator set
CHPT	Design and costing of CHP turbine-generator set
CHPM	Design and costing of CHP microturbine-generator set
ECN	Economic analysis (cash flow) calculations
BUDGET-ENG	Allocates recip. engine project costs to calculate economic benefits
BUDGET-DIR	Allocates direct-use project costs to calculate economic benefits
BUDGET-RNG	Allocates RNG project costs to calculate economic benefits
ECON-BEN SUMMARY	Summary of economic benefits and job creation analysis

INST: General Instructions and Guidelines

- Glossary of Input and Output Parameters – The definitions contained within these two tables in the model are provided in the "INP-OUT: Inputs/Outputs" section below.
- LFG Energy Project Types and Recommended Sizes – This table outlines the 11 LFG energy project types included in LFGcost-Web, as shown in Table 2 below. In addition, project sizes are recommended for each type of LFG energy project, with units varying by project type as follows:
  - Direct-use, boiler retrofit, RNG and CNG projects - cubic feet per minute (ft^3/min) of LFG.
  - Projects generating electricity (engines, turbines and microturbines) - amount of electricity generated in kilowatts (kW) or megawatts (MW).

  LFGcost-Web is designed to accommodate the recommended size ranges given for each type of LFG energy project. Model output results may not be valid for project sizes outside of the recommended project size ranges.

- Workbook Design – This table summarizes the name and function for each of the 27 worksheets contained in LFGcost-Web, as shown in Table 1 above.
- Important Notes – The items listed under ***Important Notes*** in the model are described in more detail in the "Using LFGcost-Web" section above.

Table 2. LFG Energy Project Types and Recommended Sizes

LFG Energy Project Type	Recommended Project Size
Direct-use (Boiler, Greenhouse, etc.)	400 to 3,000 ft^3/min LFG
Boiler Retrofit	Less than or equal to 3,000 ft^3/min LFG
RNG Processing Plant	1,000 to 6,000 ft^3/min LFG
Onsite CNG Production and Fueling Station	50 to 600 ft^3/min LFG
Standard Turbine-Generator Sets	Greater than 3 MW
Standard Reciprocating Engine-Generator Sets	800 kW and greater
Microturbine-Generator Sets	30 to 750 kW
Small Reciprocating Engine-Generator Sets	100 kW to 1 MW
CHP Reciprocating Engine-Generator Sets	800 kW and greater
CHP Turbine-Generator Sets	Greater than 3 MW
CHP Microturbine-Generator Sets	30 to 300 kW

INP-OUT: Inputs / Outputs

- Required User Inputs – These inputs **MUST** be entered to properly characterize the landfill and project parameters. Defaults are not provided for the required inputs because they are unique for each landfill and project.
  - **Year landfill opened –** Four-digit year that the landfill opened or is planning to open.
  - **Year of landfill closure –** Four-digit year that the landfill closed or is expected to close.
  - **Area of LFG wellfield to supply project** – Acreage of the landfill that contains waste and generates LFG to be collected and utilized by the LFG energy project. The model assumes one well per acre to determine vertical gas well, wellhead, pipe gathering system and other costs for the collection and flaring system. Acreage should represent area of landfill for gas collection to feed project, not total landfill area. Gas collection and flaring cost estimates represent a complete new system (costs for expansion of an existing system will be higher); inaccurate cost estimates may result for smaller landfill areas (<10 acres) due to economic infeasibility of designing and installing an entire new collection and flaring system.
  - **Method for entering waste acceptance data –** Unless a project size is selected to be 'Defined by user' in the optional user inputs section, the user must choose one of the three methods listed to represent average or actual tonnage of municipal solid waste (MSW) accepted each year the landfill is open. The waste data are used to calculate flow rate for projects that are not user-specified sizes.
    - Average annual waste acceptance rate – Average annual tons of MSW accepted each year the landfill is open. This method should be used if actual yearly waste acceptance data are unknown.
    - Waste acceptance rate calculator – see "WASTE: Waste Calculator/Disposal History" section below.
    - Annual waste disposal history – see "WASTE: Waste Calculator/Disposal History" section below.
  - **LFG energy project type** – Pick list to choose one of the 11 LFG energy project types you want to analyze. Table 2 (above) contains a list of project types to use for selecting the project type appropriate for the size of your project.
  - **Will LFG energy project cost include collection and flaring costs?** – Determines if costs for new vertical well collection and flaring equipment (not expansion of existing equipment) are included in the total LFG energy project cost.
    - Select Y (for yes) if the landfill does NOT have collection and flaring equipment installed and you want to include collection and flaring costs in the total project cost.
    - Select N (for no) if the landfill already contains a collection and flaring system or you do not want to include collection and flaring costs in the total project cost.

    Collection and flaring costs cannot be included if boiler retrofit costs are not combined with direct-use project costs.
  - **For Boiler Retrofits: Will boiler retrofit costs be combined with direct-use project costs?** – Determines if direct-use project costs are included in the total LFG energy project cost.
    - Select Y (for yes) if boiler retrofit costs are to be combined with other direct-use project costs (i.e., developer incurs all costs).
    - Select N (for no) if boiler retrofit costs are kept separate (i.e., end user incurs boiler retrofit costs only).

    This input is discussed in further detail in Appendix E (Evaluating Boiler Retrofit Projects). Collection and flaring costs cannot be included if N is entered or input cell is left blank.
  - **For Boiler Retrofits: Distance between end user's property boundary and boiler** – Number of miles between the end user's property boundary and the boiler.

INP-OUT: Inputs / Outputs

Required User Inputs (continued)

- **For Direct-use, RNG and CHP projects: Distance between landfill and end use, pipeline or CHP unit**
  - For direct-use projects, the number of miles between the landfill and the end user of the LFG. When costs are combined for direct-use and boiler retrofit projects, this input is the distance from the landfill to the end user's property boundary.
  - For RNG projects, the number of miles between the landfill and the natural gas pipeline or the end user of the RNG.
  - For CHP projects, the number of miles between the landfill and the CHP engine, turbine or microturbine.

  To maintain integrity of the cost estimates, this distance should be limited to 10 miles or less.
- **For CHP projects: Distance between CHP unit and hot water/steam user** – Number of miles between the CHP engine, turbine or microturbine and the end user of the hot water/steam. To maintain integrity of the cost estimates, this distance should be limited to 1 mile or less. The CHP unit and the hot water/steam user are typically co-located, which would be a distance of zero (0) miles.
- **Year LFG energy project begins operation** – Four-digit year that the LFG energy project installation will be complete and begin operating. The model requires the year to be between 2010 and 2030.
- **Will model calculate avoided CO_2 from energy generation at electricity projects?** – Determines if avoided CO_2 emissions will be calculated by the model for electricity projects.
  - Select Y (for yes) if you prefer the model to calculate these emissions. Then go to the AVOIDED CO2- ELEC worksheet to select the appropriate grid factor, using *Annual Energy Outlook* 2023 data, or follow the instructions in the AVOIDED CO2- ELEC worksheet to select the grid factor for another year of *Annual Energy Outlook* data.
  - Select N (for no) if you do not want to calculate the avoided emissions for electricity projects.

  Note: avoided emissions for non-electricity generating projects will be calculated, regardless of selection.

- Optional User Inputs – These inputs are initially set to the suggested defaults provided. To edit the optional inputs, enter the requested input in the ***Optional User Input Data*** column. (Note: Data in the ***Suggested Default Data*** column are protected and cannot be edited.)
  - **LFG energy project size** – Pick list to choose LFG flow rate over the project life used to design the LFG energy project – Minimum, Average, Maximum or Defined by user. When 'Defined by user' is selected, an LFG design flow rate MUST be entered in the input box below the LFG energy project size selection. The default is for minimum LFG generation. However, the optimum project size will vary for different project types. You are encouraged to try multiple size options to determine the optimum size for your project conditions.
    - For direct-use projects, the optimum size is often based on the maximum gas flow.
    - The optimum size for electricity generation projects (including CHP) is often based on the average flow.
  - **For user-defined project size only: Design flow rate –** The design LFG flow rate, in cubic feet per minute, entered for projects sized manually by users. 'Defined by user' MUST be selected for LFG energy project size to indicate the project size is user-defined. A user-defined project size can be entered without waste data. Since waste data are used to calculate flow rate, you will receive a warning message indicating that the user-defined project size exceeds the maximum calculated LFG flow rate in cell AG28 of the FLOW worksheet. Further, if you are using waste data to estimate flow rate, this warning message is indicating that the landfill may not have enough gas available for this project.

INP-OUT: Inputs / Outputs

Optional User Inputs (continued)

- **Methane generation rate constant, k** – The methane generation constant (k) used to determine the amount of LFG generated generally varies depending on the climate of the area surrounding the landfill. There are three k values to choose from: 0.04 per year for areas that receive 25 inches or more of rain annually; 0.02 per year for drier (arid) areas that receive less than 25 inches of rain annually; or 0.1 per year for bioreactors. The suggested default is 0.04 per year for typical climates. The k value entered should equal one of these suggested values unless site-specific data are available. k values are discussed further in the "FLOW: Landfill Gas Flow Rate Calculations" section below.
- **Potential methane generation capacity of waste, L_O** – The potential methane generation capacity of the waste (L_O) in cubic feet per ton. This parameter primarily depends on the type of waste in the landfill. The default of 3,204 cubic feet per ton should be used to represent MSW unless site-specific data are available. L_O values are discussed further in the "FLOW: Landfill Gas Flow Rate Calculations" section below.
- **Methane content of landfill gas** – The methane content of LFG generally ranges between 45 and 60 percent. This parameter is used to calculate environmental benefits and normalize LFG production. The default of 50 percent should be used unless site-specific data are available.
- **Average depth of landfill waste** – The average depth of the landfill waste (in feet) is used to estimate costs of the vertical gas wells for the new collection and flaring system (not expansion of existing system). The suggested default is 65 feet, but this should be changed if site-specific average waste depth is known for the landfill.
- **Landfill gas collection efficiency** – The equipment used to collect LFG normally operates at efficiencies between 70 and 95 percent. The suggested default is 85 percent.
- **Utilization of CHP hot water/steam potential** – For CHP projects, the percent of hot water/steam used by the end user, out of the potential hot water/steam generated by the CHP unit. The range for the utilization is between 0 and 100 percent. The suggested default is 100 percent.
- **Expected LFG energy project lifetime** – Estimated number of years that the LFG energy project will be operating. The default project lifetime is 15 years, but the model sets the lifetime to 10 years for microturbines (non-CHP applications). The project lifetime for all other project types should be greater than or equal to 10 years but cannot exceed 15 years.

  Generally, 15 years is considered the average lifetime for the equipment installed in LFG energy projects and thus, the longest period over which to evaluate project economics. In addition, LFGcost-Web uses the project lifetime for determining the tax-based capital depreciation rate. In Section 179 of the 2001 Federal Tax Code, the IRS recommends using 15 years for the depreciation of electricity and fuel pipeline projects that are analogous to LFG energy projects. For these reasons, the default project lifetime is 15 years and it is recommended not to use a value of less than 10 years or more than 15 years. However, microturbine projects (non-CHP applications) should be set to a project lifetime of 10 years to match their expected life of 10 years, as observed by manufacturers of LFG microturbines.
- **Operating schedule** – LFG may be used seasonally (e.g., for space heating six months out of the year). This parameter allows users to specify how many hours of the day, days of the week and weeks of the year the project will be requiring LFG. The suggested defaults are 24 hours per day, 7 days per week and 52.14 weeks per year to result in the maximum operating schedule of 8,760 hours per year.

INP-OUT: Inputs / Outputs

Optional User Inputs (continued)

- **GWP of methane** – The suggested default GWP of methane is 28 to reflect the Fifth Assessment Report (AR5) of the Intergovernmental Panel on Climate Change (IPCC). This parameter is used to calculate environmental benefits and direct methane reductions for greenhouse gas reduction credits. This default is consistent with the use of IPCC AR5 GWP values by the annual *Inventory of U.S. Greenhouse Gas Emissions and Sinks* submitted to the UNFCCC and emissions reported by large facilities and industrial suppliers to EPA's Greenhouse Gas Reporting Program. Users may enter an alternate GWP value, if desired.
- **Will cost of metering station that serves as custody transfer point be borne by end user?** – For boiler retrofit projects, determines if the cost to install a metering station will be incurred by the end user because it will serve as a custody transfer point.
- Select Y (for yes) if metering station costs will be included.
- Select N (for no) if metering station costs will not be included.

  The suggested default is Y, to include metering station costs.
- **Loan lifetime** – The period over which the project loan will be repaid. The loan lifetime is assumed to begin during the year of project design and construction. It is common for project loan periods to be limited to half or two-thirds of the equipment lifetime to assure that the loan is repaid before the project ends. Since much of the equipment used in LFG energy projects has a projected lifetime of 15 years, the default loan lifetime is set to 10 years. However, loan lifetime should not exceed the project lifetime, because it is not practical to assume that project financing would exceed the expected life of the project equipment and revenues. See Appendix A for additional information.
- **Interest rate** – The actual or "nominal" interest rate of the project loan. The suggested default is 4 percent based on recent Moody Corporate AAA and BAA bond rates published by the Federal Reserve. See Appendix A for additional information.
- **General inflation rate –** The inflation rate applied to O&M costs. The suggested default is 4 percent based on recent Consumer Price Indexes. See Appendix A for additional information.
- **Equipment inflation rate** – The inflation rate applied to project equipment (capital) costs. The suggested default is 8 percent based on recent plant construction cost indices. See Appendix A for additional information.
- **Marginal tax rate** – The tax rate used to estimate tax payments; this item is not applicable to projects funded and developed by local governments. For publicly owned projects, see Appendix D (Evaluating Local Government-Owned Projects). The suggested default tax rate is 21 percent for projects funded and developed by private entities, which is based on recent LFG energy project experience with commercial projects. See Appendix A for additional information.
- **Discount rate** – The discount rate, or hurdle rate, is used to determine the present value of future cash flows. This rate represents the internal time-value of money (on an actual or "nominal" basis) used by companies to evaluate projects. The suggested default is 9 percent based on recent LFG energy project experience with commercial projects. See Appendix A for additional information.
- **Down payment** – The down payment on the project loan. The suggested default is 20 percent based on recent LFG energy project experience with commercial projects. See Appendix A for additional information.

INP-OUT: Inputs / Outputs

Optional User Inputs (continued)

- **Energy tax credits** – Energy tax credits may be available for LFG utilization projects in select areas. These energy tax credits include LFG or RNG utilization ($/million Btu) and electricity generation ($/kWh). Municipalities installing LFG energy projects are generally tax exempt and are not directly eligible for tax credits. In these instances, the values for the tax credits should be entered as zero. However, a municipality may arrange to sell the tax credits to a third party. In this situation, only the third-party payment to the municipality, provided in return for the tax credit, should be entered as energy tax credits in LFGcost-Web. All the default values are initialized to zero.
- **Direct credits** – Other credits can be evaluated for special situations. All the default values are initialized to zero.
  - *Greenhouse gas reduction credit ($/MTCO$_2$E)* – for direct methane reductions from the landfill and avoided carbon dioxide generated from displacing fossil fuels (in units of $ per metric ton of carbon dioxide equivalents). Direct methane reductions (i.e., methane collected and either flared or utilized in an LFG energy project) may contribute to this credit if the landfill is not required to collect and combust LFG (e.g., complying with the NSPS/EG). You have the option of including (Y for yes) or excluding (N for No) direct methane reductions. The suggested default is Y, to include direct methane reductions.
  - *Renewable electricity credit ($/kWh)* – represents tradable renewable certificates (TRCs) or "green tags" that are created when a renewable energy facility generates electricity (in units of $ per kilowatt-hour). Each unique certificate represents all the environmental benefits of a specific quantity of renewable electricity generation, namely the benefits received when fossil fuels are displaced.
  - *Renewable fuel credit ($/GGE)* – for alternative vehicle fuel (CNG and RNG) projects, including projects with Renewable Identification Numbers (RINs) where a gallon of renewable fuel produced in or imported into the United States receives a credit. A typical arrangement is that the RNG project developer will retain approximately 70 percent of the renewable fuel credit while the remainder of the credit goes to the gas marketer, the station owner or the fleet. Since pricing for RINs is based on ethanol gallon equivalents, to calculate the price of the credit on a $/GGE basis, multiply the credit price by the ratio of the heating value of gasoline to ethanol (115,400 Btu/gal gasoline divided by 75,700 Btu/gal of ethanol), or a factor of 1.52.
  - *Construction grant ($)* – a government cash grant for project capital costs.
- **Royalty payment for landfill gas utilization** – Project developers that do not own the LFG may be required to pay the landfill owner a royalty for the amount of gas utilized (in units of $ per million Btu). The default is initialized to zero.
- **Initial year product price** – Initial year product prices are suggested for the sale of energy from the project. These prices represent the initial year of project operation. See Appendix A for additional information and documentation of the review of current product prices used to determine the following suggested default prices:
  - Landfill gas production – $2.65/million Btu
  - Electricity generation – $0.066/kWh
  - CHP hot water/steam production – $4.73/million Btu
  - RNG production – $2.65/million Btu
  - CNG production – $2.27/gasoline gallon equivalent (GGE) [to determine $/diesel gallon equivalent (DGE), divide $/GGE by 0.866]

INP-OUT: Inputs / Outputs

Optional User Inputs (continued)

- **Annual product price escalation rate** – The initial year product price will be escalated by this annual value in the future years of the project. The suggested default for electricity prices is -7.0 percent, for CNG prices is -5.8 percent and for direct-use or RNG prices is -6.4 percent. This rate represents an escalation in real prices as discussed in Appendix A.
- **Electricity purchase price for projects NOT generating electricity** – The price for electricity purchased by projects that do not generate their own electricity, such as direct-use projects. The suggested default is $0.103 per kWh, as discussed in Appendix A.
- **Annual electricity purchase price escalation rate** – The annual escalation rate applied to purchased electricity. The suggested default is -2.5 percent, as discussed in Appendix A.
- **RNG pipeline interconnection fee –** The fees associated with interconnecting a project with an established pipeline. Since this fee varies widely and is utility-specific, there is no default value. Users may enter a fee if desired for their project. The value entered should reflect the fee anticipated in the first year the project will operate.
- **RNG pipeline injection fee –** This is a necessary fee for most projects, but it can vary widely depending on the pipeline injection location. The local utility may offer a more specific number. The suggested default is $2.50 per MMBtu based on typical fees paid from recent LFG energy contracts in the range of $2 to $3 per MMBtu.
- **RNG technology methane capture rate –** The default for this input is set to 90 percent, but this rate can vary significantly between technology types and system-specific design goals. LMOP's RNG Flow Rate Estimation Tool offers the following values:
  - 65 to 80% for single pass membrane technology
  - 96 to 99% for multiple pass membrane technology
  - 95 to 98% for Pressure Swing Adsorption (PSA) systems
  - 97 to 99% for solvent scrubbing processes with physical solvents
  - Over 99% for solvent scrubbing processes with amine solvents
  - Over 99% for water scrubbing systems
- **RNG product use** – The end use of the RNG product. If Vehicle Fuel is chosen, this allows for a renewable fuel credit to be applied by the user, if applicable. This user selection also affects how avoided carbon dioxide emissions are calculated, as natural gas parameters are used to calculate the offsets for Direct Thermal Use applications while diesel parameters are used for Vehicle Fuel.

- Outputs – Results of the economic analysis and environmental benefits. Economic outputs are discussed further in the "ECN: Economic Analysis" section below.

  Economic Analysis (Individual project costs can vary by ±30-50% due to situational factors):

  - **Design project size** –The amount of LFG (in cubic feet per minute) used to determine the design flow rate of the project.
  - **Generating capacity for projects generating electricity** – For electricity generation projects, the generation capacity (in kilowatts) of the power producing equipment.
  - **Average project size for projects NOT generating electricity** – For direct-use, boiler retrofit, RNG and CNG projects, average project size represents the average amount of actual LFG utilized over the lifetime of the LFG energy project. This output is presented in units of million cubic feet per year and cubic feet per minute.
  - **Average project size for projects generating electricity** – For engine, turbine, microturbine and CHP projects, average project size represents average annual kilowatt-hours of electricity generated (net).
  - **Average project size for CHP projects producing hot water/steam** – For CHP projects, average project size represents the average annual amount of hot water/steam produced in units of million Btu per year.

INP-OUT: Inputs / Outputs

Outputs: Economic Analysis (continued)

- **Total installed capital cost for year of construction** – Total capital cost of the installed LFG energy project.
- **Annual costs for initial year of operation** – Equipment operating and maintenance (O&M) cost for the initial year of the LFG energy project.
- **Internal rate of return** – Return on investment based on the total revenue from the project and construction grants, minus down payment (i.e., cash flow). More simply, the rate that balances the overall costs of the project with the revenue earned over the lifetime of the project such that the net present value of the investment is equal to zero.
- **Net present value at year of construction** – First year monetary value that is equivalent to the various cash flows, based on the discount rate (which is defaulted to 9 percent, as discussed in Appendix A). In other words, the NPV is calculated as the present value of a stream of current and future benefits minus the present value of a stream of current and future costs.
- **Years to breakeven** – Years required for the total present value to exceed zero. An output of "None" means there is no return on investment or no payback in the LFG energy project lifetime.

Environmental Benefits:

- **Total lifetime amount of methane collected and destroyed** – Total million cubic feet of methane that is collected and either destroyed by the flare (assuming 100 percent destruction efficiency) or utilized by the LFG energy project.
- **Average annual amount of methane collected and destroyed** – Average annual million cubic feet of methane that is collected and either destroyed by the flare (assuming 100 percent destruction efficiency) or utilized by the LFG energy project on a yearly basis.
- **GHG value of total lifetime amount of methane utilized in energy project*** – Total million metric tons of methane (represented by carbon dioxide equivalents, or $MMTCO_2E$) that is utilized by the LFG energy project. This output takes into account the operating schedule and gross capacity factor of the project. Flared gas is not included in this value.
- **GHG value of average annual amount of methane utilized in energy project*** – Average annual million metric tons of methane (represented by carbon dioxide equivalents per year, or $MMTCO_2E$ per year) that is utilized by the LFG energy project on a yearly basis. This output takes into account the operating schedule and gross capacity factor of the project. Flared gas is not included in this value.
- **Total lifetime carbon dioxide from avoided energy generation*** – Total emissions that are avoided because LFG is utilized instead of combusting fossil fuels. This output is presented in units of million metric tons of carbon dioxide equivalents. For direct-use, boiler retrofit and RNG projects for direct thermal use, LFG is assumed to offset the combustion of natural gas. For CNG or RNG vehicle fuel projects, LFG is assumed to offset the combustion of diesel fuel. For projects that generate electricity (turbines, engines and microturbines), electricity produced is assumed to offset the emissions from the local electricity market module region where the project is located. See the Avoided CO2- ELEC page for additional discussion on how to estimate these values.
- **Average annual carbon dioxide from avoided energy generation*** – Average annual emissions that are avoided because LFG is utilized instead of combusting fossil fuels. This output is presented in units of million metric tons of carbon dioxide equivalents per year. For direct-use, boiler retrofit and RNG for direct thermal use projects, LFG is assumed to offset the combustion of natural gas. For CNG or RNG vehicle fuel projects, LFG is assumed to offset the combustion of diesel fuel. For projects that generate electricity (turbines, engines and microturbines), electricity produced is assumed to offset the emissions from the local electricity market module region where the project is located. See the Avoided CO2- ELEC page for additional discussion on how to estimate these values.

*Note: These output values are presented in scientific notation. This format is used because these outputs are smaller values, typically less than 0.1. An output value of 1.23E-02 is equivalent to 1.23×10^{-2} or 0.0123.

WASTE: Waste Calculator / Disposal History

- Waste Acceptance Rate Calculator – calculates the average annual waste acceptance rate in tons per year based upon the amount of waste-in-place and the year representing the time required to accumulate this amount of MSW. This calculator is meant to be used when average or year-to-year annual acceptance rates are unknown.
  - **Waste-in-place –** total tons of MSW accepted and placed in the landfill.
  - **Year representing waste-in-place** – four-digit year that corresponds to the waste-in-place tonnage.

- OR -

- Annual Waste Disposal History – this table allows users to enter yearly waste acceptance rate data in tons per year for up to 75 years. The waste disposal history should be used **only** when year-to-year waste acceptance is known for each year that the landfill operates. In other words, the annual waste acceptance column **must** be completed for all years beginning with the landfill open year and ending with the landfill closure year. The ***Year*** and ***Waste-In-Place*** columns within the table are protected and cannot be edited.
  - **Year** – four-digit year with Year 0 being the open year of the landfill.
  - **Annual waste acceptance** – tons of MSW accepted per year for the corresponding year.
  - **Waste-in-place** – a cumulative total of the tonnage of MSW accepted for previous years.

REGIONAL PRICING: Regional Electricity Pricing

- A lookup table for 2024 electricity prices for each electricity market module is available for users that want to reference a more regional price basis for selling LFG electricity or purchasing electricity to run a gas collection and control system. These reference prices can be used to replace the national average default values in cell D58 or cell D63 of the INP-OUT worksheet.
- The basis of the prices in the lookup table is the *Annual Energy Outlook* 2023 published by the U.S. Energy Information Administration (EIA).

CURVE: Landfill Gas Curve

- The graph presented on the CURVE worksheet displays the LFG generation, collection and utilization in average standard cubic feet per minute from the year the project begins operations to 25 years beyond start-up.
  - The LFG generation curve is represented by a thick solid line and shows the estimated amount of gas that the landfill is capable of producing. The gas generation does not take into account the fact that not all the gas is recoverable.
  - The LFG collection curve is represented by a thin solid line and provides an estimate for the amount of gas collected. The gas collection rate is estimated by multiplying the gas generation rate by the collection efficiency. For more information about collection efficiency, please see the "INP-OUT: Inputs/Outputs" section above.
  - The LFG utilization curve is shown as a dashed line and represents the amount of gas utilized by the project for the years the project is operating. Collection efficiency, project size, operating schedule, gross capacity factor and parasitic loss efficiency are taken into account when calculating the LFG utilization. An example of the LFG generation, collection and utilization curve is shown in Figure 1 for a 15-year project beginning operation in 2015.

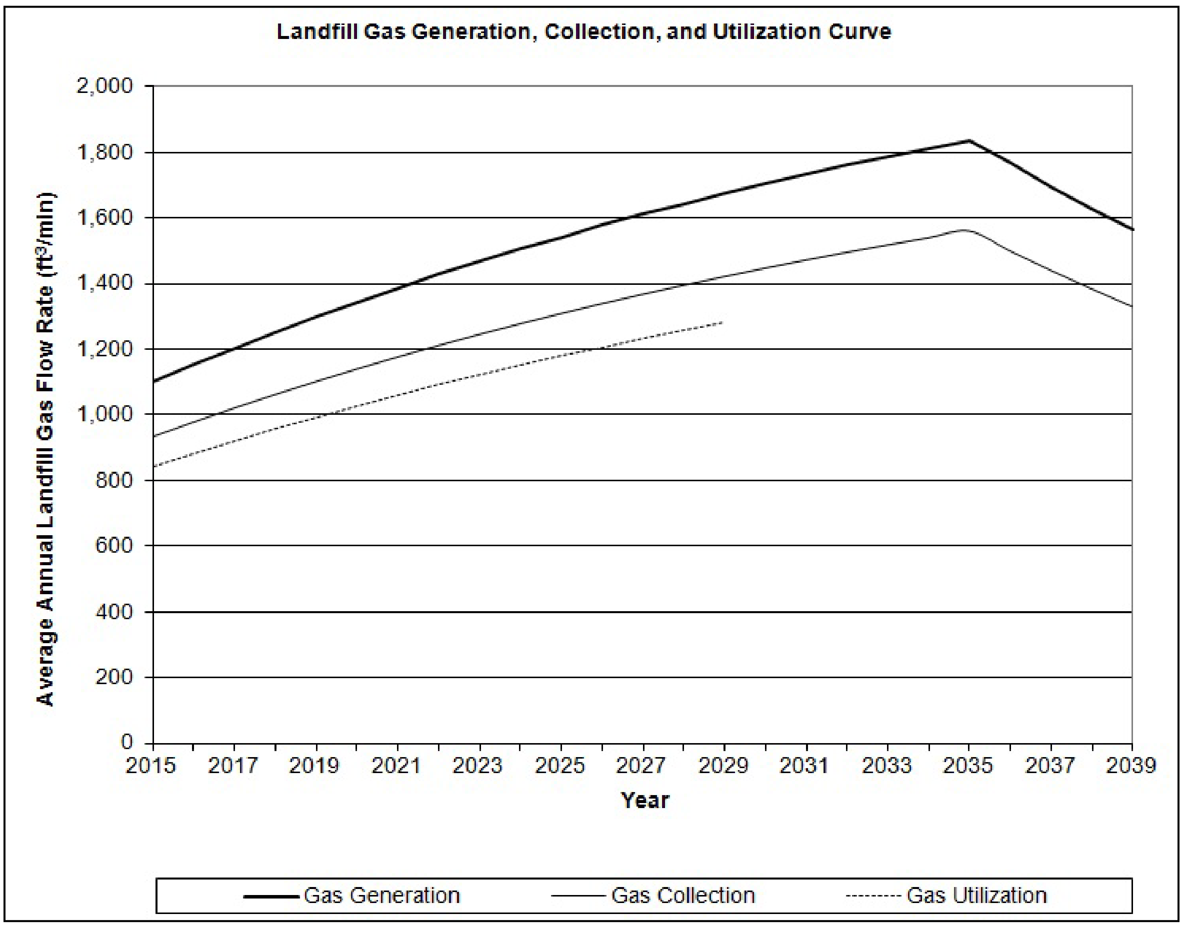

Figure 1. Example of LFG generation, collection and utilization curve in LFGcost-Web

AVOIDED CO_2 - ELEC: Regional Grid Carbon Dioxide Avoided Emission Factors

- A lookup table for 2022 through 2032 projected CO_2 emission factors for each electricity market module is available for users that want to estimate avoided CO_2 emissions from an LFG electricity generating project. A user must select the factor of interest and enter it in cell C10 of the ENV worksheet. In addition, the user must indicate "Y" in cell C20 of the INP-OUT worksheet to indicate a preference to estimate avoided CO_2 emissions.
- The basis of the factors in the lookup table is the *Annual Energy Outlook* 2023 published by EIA.
- Below the lookup table is a hyperlink to the generic *Annual Energy Outlook* website and instructions to allow users to re-calculate avoided CO_2 emission factors as new datasets are released by EIA.

ENV: Environmental Benefits

- Environmental benefits are determined for each year of the LFG energy project. The benefits are calculated separately for projects that DO NOT generate electricity and projects that DO generate electricity. The four primary calculations that occur for each type of project are listed below:

  – **Methane collected and destroyed** – total annual amount of methane (in cubic feet per year, ft^3/yr) that is collected and either destroyed by the flare or utilized by the LFG energy project.

$$\begin{pmatrix} Methane\,collected \\ and\ destroyed \\ (ft^3/yr) \end{pmatrix} = \begin{pmatrix} Annual\ gas \\ collection \\ (ft^3/yr) \end{pmatrix} * \begin{pmatrix} \%\,methane \\ in\,LFG \end{pmatrix}$$

  – **Direct methane reduced –** total annual amount of methane (in million metric tons carbon dioxide equivalents per year, $MMTCO_2E/yr$) that is collected and either destroyed by the flare or utilized by the LFG energy project.

$$\begin{pmatrix} Direct\ methane \\ reduced \\ (MMTCO_2E/yr) \end{pmatrix} = \begin{pmatrix} Methane\,collected \\ and\ destroyed \\ (ft^3/yr) \end{pmatrix} * \left(\frac{0.0423\,lbs\,methane}{ft^3\ methane}\right) * \left(\frac{short\ ton}{2{,}000\,lbs}\right) * \left(\frac{0.9072\,MT}{short\ ton}\right) * \begin{pmatrix} GWP\,of \\ methane \end{pmatrix} * \left(\frac{MMT}{10^6\ MT}\right)$$

  – **Methane utilized by project** – annual million metric tons of methane (in $MMTCO_2E/yr$) that is utilized by the LFG energy project.

$$\begin{pmatrix} Methane\ utilized \\ (MMTCO_2E/yr) \end{pmatrix} = \begin{pmatrix} Actual\ gas \\ utilization \\ (ft^3/yr) \end{pmatrix} * \begin{pmatrix} \%\,methane \\ in\,LFG \end{pmatrix} * \left(\frac{0.0423\,lbs\,methane}{ft^3\ methane}\right) * \left(\frac{short\ ton}{2{,}000\,lbs}\right) * \left(\frac{0.9072\,MT}{short\ ton}\right) * \begin{pmatrix} GWP\,of \\ methane \end{pmatrix} * \left(\frac{MMT}{10^6\ MT}\right)$$

ENV: Environmental Benefits

Environmental Benefits (continued)

- **Avoided carbon dioxide emissions** – annual carbon dioxide emissions avoided because LFG is utilized instead of combusting fossil fuels ($MMTCO_2E/yr$).
    - For direct-use, boiler retrofit and RNG for direct thermal use projects, carbon dioxide emissions typically offset the combustion of natural gas. The emission factor of 0.12037 pounds carbon dioxide per cubic foot natural gas (conversion from kg CO_2 per million Btu) is referenced in Table C-1 of "2013 Revisions to the Greenhouse Gas Reporting Rule" (Nov. 2013), https://www.gpo.gov/fdsys/pkg/FR-2013-11-29/pdf/2013-27996.pdf.
    - For CNG or RNG vehicle fuel projects, carbon dioxide emissions typically offset the combustion of diesel fuel. The emission factor of 161 pounds carbon dioxide per million Btu (conversion from kg CO_2 per million Btu for Distillate Fuel Oil) is referenced in Table C-1 of "2013 Revisions to the Greenhouse Gas Reporting Rule" (Nov. 2013), https://www.gpo.gov/fdsys/pkg/FR-2013-11-29/pdf/2013-27996.pdf.
    - For projects that generate electricity (turbines, engines and microturbines, including CHP), carbon dioxide emissions offset the combustion of fossil fuels. The emission factor will vary by region in which the project is located. The AVOIDED CO2-_ELEC worksheet contains the grid-specific emission factors, in units of pounds carbon dioxide per kilowatt-hour, for 2022 through 2032, based on the *Annual Energy Outlook* 2023. The user must select the appropriate factor for the model to compute an estimate. CHP avoided carbon dioxide emissions are determined using the same natural gas emission factor as direct-use projects, as described above.

Direct-use and boiler retrofit projects:

$$\begin{pmatrix} \textit{Direct-use avoided} \\ \textit{carbon dioxide} \\ \textit{emissions} \\ (MMTCO_2E/yr) \end{pmatrix} = \begin{pmatrix} \textit{Actual gas} \\ \textit{utilization} \\ (ft^3/yr) \end{pmatrix} * \begin{pmatrix} \%\,CH_4 \\ \textit{in LFG} \end{pmatrix} * \left(\frac{1{,}012\ Btu}{ft^3\ \textit{methane}} \right) * \left(\frac{ft^3\ \textit{natural gas}}{1{,}050\ Btu} \right)$$

$$* \left(\frac{0.12037\ lbs\ CO_2}{ft^3\ \textit{natural gas}} \right) * \left(\frac{\textit{short ton}}{2{,}000\ lbs} \right) * \left(\frac{0.9072\ MT}{\textit{short ton}} \right) * \left(\frac{MMT}{10^6\ MT} \right)$$

RNG projects with direct thermal product use:

$$\begin{pmatrix} \textit{RNG avoided} \\ \textit{carbon dioxide} \\ \textit{emissions} \\ (MMTCO_2E/yr) \end{pmatrix} = \begin{pmatrix} \textit{Actual gas} \\ \textit{utilization} \\ (ft^3/yr \end{pmatrix} * \begin{pmatrix} \%\ CH_4 \\ \textit{in LFG} \end{pmatrix} * \begin{pmatrix} \textit{RNG technology} \\ \textit{methane} \\ \textit{capture rate}\ (\%) \end{pmatrix} * \left(\frac{1{,}012\ Btu}{ft^3\ \textit{methane}} \right)$$

$$* \left(\frac{ft^3\ \textit{natural gas}}{1{,}050\ Btu} \right) * \left(\frac{0.12037\ lbs\ CO_2}{ft^3\ \textit{natural gas}} \right) * \left(\frac{\textit{short ton}}{2{,}000\ lbs} \right) * \left(\frac{0.9072\ MT}{\textit{short ton}} \right) * \left(\frac{MMT}{10^6\ MT} \right)$$

ENV: Environmental Benefits

Environmental Benefits (continued)

RNG projects with vehicle fuel product use the following, assuming an offset of diesel vehicle fuel:

$$\begin{pmatrix} RNG\ avoided \\ carbon\ dioxide \\ emissions \\ (MMTCO_2E/yr) \end{pmatrix} = \begin{pmatrix} Actual\ gas \\ utilization \\ (ft^3/yr) \end{pmatrix} * \begin{pmatrix} \%\ CH_4 \\ in\ LFG \end{pmatrix} * \begin{pmatrix} RNG\ technology \\ methane \\ capture\ rate\ (\%) \end{pmatrix} * \left(\frac{1{,}012\ Btu}{ft^3\ methane}\right) * \left(\frac{161\ lbs\ CO_2}{millionBtu}\right) * \left(\frac{millionBtu}{10^6\ Btu}\right) * \left(\frac{short\ ton}{2{,}000\ lbs}\right) * \left(\frac{0.9072\ MT}{short\ ton}\right) * \left(\frac{MMT}{10^6\ MT}\right)$$

CNG projects:

$$\begin{pmatrix} CNG\ avoided \\ carbon\ dioxide \\ emissions \\ (MMTCO_2E/yr) \end{pmatrix} = \begin{pmatrix} Actual\ gas \\ utilization \\ (ft^3/yr) \end{pmatrix} * \begin{pmatrix} \%\ CH_4 \\ in\ LFG \end{pmatrix} * \left(\frac{65\%\ Conversion\ Efficiency\ LFG\ CH_4}{CNG\ CH_4}\right)\left(\frac{1{,}012\ Btu}{ft^3\ methane}\right) * \left(\frac{161\ lbs\ CO_2}{millionBtu}\right) * \left(\frac{millionBtu}{10^6\ Btu}\right) * \left(\frac{short\ ton}{2{,}000\ lbs}\right) * \left(\frac{0.9072\ MT}{short\ ton}\right) * \left(\frac{MMT}{10^6\ MT}\right)$$

Non-CHP electricity generation projects:

$$\begin{pmatrix} Electricity\ generation \\ avoided\ carbon \\ dioxide\ emissions \\ (MMTCO_2E/yr) \end{pmatrix} = \left(\frac{grid-specific\ lbs\ CO_2}{kWh}\right) * \begin{pmatrix} Net\ electricity \\ produced \\ (kWh/yr) \end{pmatrix} * \left(\frac{short\ ton}{2{,}000\ lbs}\right) * \left(\frac{0.9072\ MT}{short\ ton}\right) * \left(\frac{MMT}{10^6\ MT}\right)$$

CHP electricity generation projects:

$$\begin{pmatrix} CHP \\ avoided\ carbon \\ dioxide\ emissions \\ (MMTCO_2E/yr) \end{pmatrix} = \left(\left(\frac{grid-specific\ lbs\ CO_2}{kWh}\right) * \begin{pmatrix} Net\ electricity \\ produced \\ (kWh/yr) \end{pmatrix} * \left(\frac{short\ ton}{2{,}000\ lbs}\right) * \left(\frac{0.9072\ MT}{short\ ton}\right) * \left(\frac{MMT}{10^6\ MT}\right) \right) + \left(\begin{pmatrix} Hot\ water/steam\ produced \\ (million\ Btu/yr) \end{pmatrix} * \left(\frac{0.12037\ lbs\ CO_2}{ft^3\ (natural\ gas)}\right) * \left(\frac{short\ ton}{2{,}000 lbs}\right)\left(\frac{0.9072\ MT}{short\ ton}\right) * \left(\frac{MMT}{10^6\ MT}\right) * \left(\frac{1}{0.80(efficiency\ of\ hot\ water/steam\ boiler)}\right) * \left(\frac{ft^3 \text{natural gas}}{1{,}050 Btu}\right) * \left(\frac{10^6\ Btu}{million\ Btu}\right) \right)$$

FLOW: Landfill Gas Flow Rate Calculations

- The first-order decay equation is commonly used to estimate LFG generation from MSW landfills. LFG production is normalized for actual methane content entered in the ***Optional User Inputs*** table of the INP-OUT worksheet. The LFG generation equations used in LFGcost-Web vary slightly depending on the type of waste acceptance rate data used (see the "INP-OUT: Inputs/Outputs" section above). The two first-order decay equations used in LFGcost-Web to determine LFG generation are as follows:

  First-Order Decay Equation for Average Annual Waste Acceptance Rate:

  $$Q_t = (1/(CH_4/100)) * L_o * R * [e^{(-kc)} - e^{(-kt)}]$$

  Where,

Q_t	=	landfill gas generation rate at time t (ft^3/year)
CH_4	=	methane content of landfill gas (%)
L_o	=	potential methane generation capacity of waste (ft^3/ton)
R	=	average annual waste acceptance rate during active life (tons)
k	=	methane generation rate constant (1/year)
c	=	time since landfill closure (years)
t	=	time since the initial waste placement (years)

  First-Order Decay Equation for Waste Disposal History (year-to-year acceptance rate):

  $$Q_t = \Sigma_i [(1/(CH_4/100)) * k * L_o * M_i * e^{(-kt_i)}]$$

  Where,

Q_t	=	landfill gas generation rate at time t (ft^3/year)
CH_4	=	methane content of landfill gas (%)
k	=	methane generation rate constant (1/year)
L_o	=	potential methane generation capacity of waste (ft^3/ton)
M_i	=	waste acceptance rate in the i^{th} section (tons)
t_i	=	age of the i^{th} section (years)

- The suggested default potential methane generation capacity (L_o) is 3,204 cubic feet per ton (100 cubic meters per megagram). This default L_o value comes from EPA's "Compilation of Air Pollutant Emission Factors", commonly known as "AP-42", and is appropriate for most landfills. Estimation of L_o is generally treated as a function of the moisture and organic content of the waste. Therefore, it is recommended that users utilize L_o values that differ from these defaults only when site-specific data are available to reasonably estimate the potential methane generation capacity for a particular landfill.

FLOW: Landfill Gas Flow Rate Calculations

Landfill Gas Flow Rate Calculations (continued)

- Estimation of the methane generation rate constant (k) is a function of a variety of factors, including moisture, pH, temperature and landfill operating conditions. The constant k can vary from less than 0.02 per year to more than 0.285 per year, depending on these site-specific factors. EPA's AP-42 recommends that areas receiving 25 inches or more of rain per year use a default k of 0.04 per year, and drier (arid) areas receiving less than 25 inches of rain per year use a default k of 0.02 per year. A default k value of 0.1 per year is commonly accepted for bioreactors or wet landfills (yet values >0.1 per year are common). It is recommended that users utilize k values that differ from these defaults only when site-specific data are available to reasonably estimate the methane generation constant for a particular landfill.
- LFG flow rates are determined for each year of the LFG energy project. The eight primary calculations that occur are listed below:
  - **Annual gas generation** – cubic feet of LFG generated per year.
  - **Gas generation flow rate –** cubic feet of LFG generated per minute.
  - **Annual gas collection** – cubic feet of LFG collected per year.
  - **Gas collection flow rate** – cubic feet of LFG collected per minute.
  - **Annual project gas utilization** – cubic feet of LFG per year available for use by the LFG energy project, which depends on the project size chosen. This calculation does not account for operating schedule, gross capacity factor or parasitic loss efficiency.
  - **Project gas utilization flow rate** – cubic feet of LFG per minute available for use by the LFG energy project, which depends on the project size chosen. This calculation does not account for take operating schedule, gross capacity factor or parasitic loss efficiency.
  - **Annual actual gas utilization** – actual cubic feet of LFG utilized per year by the LFG energy project. Based on user input and the type of project chosen, this calculation accounts for project size, operating schedule, gross capacity factor and parasitic loss efficiency.
  - **Actual gas utilization flow rate** – actual cubic feet of LFG utilized per minute by the LFG energy project, on an average annual basis. Based on user input and the type of project chosen, this calculation accounts for project size, operating schedule, gross capacity factor and parasitic loss efficiency.

C&F: Collection and Flaring System	
Typical components include	▸ Engineering, permitting and administration; ▸ Wells and wellheads; ▸ Pipe gathering system (includes additional fittings/installations); ▸ Condensate knockout system; ▸ Blowers; ▸ Instrument controls; ▸ Flare; and ▸ Site survey, preparation and utilities.
Drilling and pipe crew mobilization	\$20,000
Installed capital cost of vertical gas extraction wells	$\left(\begin{matrix}\text{average waste} \\ \text{depth (ft)}\end{matrix} - 10\,\text{ft}\right) * \$85/\text{ft} = \$X/\text{well},$ (\$4,675 * number of wells) for default average waste depth of 65 feet
Installed capital cost of wellheads and pipe gathering system	\$17,000 * number of wells
Installed capital cost of knockout, blower and flare system	$(ft^3/min)^{0.61}$ * \$4,600
Engineering, permitting and surveying	\$700 * number of wells
Annual O&M cost (excluding energy costs)*	(\$2,600 * number of wells) + \$5,100 for flare
Electricity usage by blowers	0.002 kWh / ft^3

Note: Raw cost data are in 2013\$'s.

* Annual O&M for wells include the cost for monthly wellhead monitoring for gas quality and wellhead adjustment purposes as well as the cost to maintain each well.

DIR: Direct-Use System	
Typical components include	• Engineering, permitting and administration; • Skid-mounted filter, compressor and dehydration unit; • Pipeline to convey gas to project (includes below-grade HDPE piping, condensate removal system and pipe fittings); and • Site survey, preparation and utilities. (Cost does not include payments for right-of-way easements which may or may not be required.)
Installed capital cost of skid-mounted filter, compressor and dehydration unit	(\$360 * ft^3/min) + \$830,000
Installed capital cost of pipeline	*For flow rates ≤1,000 ft^3/min (8" piping):* (\$80* feet of pipeline) + \$178,000 *For flow rates 1,001 - 3,000 ft^3/min (12" piping):* (\$106 * feet of pipeline) + \$207,000
Annual O&M cost (excluding electricity)	$\$57{,}000 * \left(\frac{\mathrm{ft}^3/\mathrm{min}}{700}\right)^{0.2}$
Electricity usage	*For pipeline distances of 5 miles or less:* 0.002 kWh/ft^3 *For pipeline distances where* $\left(\frac{miles * (ft^3/\min)^2}{10^6}\right) > 120:$ 0.003 kWh/ft^3
Gross capacity factor*	Assume 90%

Note: Raw cost data are in 2013\$'s.

* Gross capacity factor accounts for loss of energy production due to problems in the gas collection system, problems with project equipment, weather related interruptions of the local utilities and shut-downs at the energy consumer end of the system.

BLR: Boiler Retrofit	
Typical components include	‣ Pipeline delivery from end user's property boundary to boiler (includes below-grade HDPE piping, condensate removal system and pipe fittings, engineering, permitting and administration); ‣ Metering station (includes LFG analyzer and flow meter and moisture analyzer); and ‣ Boiler conversion for seamless controls (includes fuel delivery system, burner modifications and control modifications). Raw cost data for boiler conversion provided by CPL Systems, Inc.
Installed capital cost of pipeline delivery from end user's property boundary to boiler	*For flow rates ≤1,000 ft³/min (8" piping):* $75 * (feet of pipeline) + $88,000 *For flow rates 1,001 - 3,000 ft³/min (12" piping):* $100 * (feet of pipeline) + $105,500
Installed capital cost of metering station	*For flow rates ≤1,000 ft³/min:* $79,000 *For flow rates 1,001 - 3,000 ft³/min:* $89,000
Installed capital cost of boiler conversion for seamless controls*	($113 * ft³/min) + $84,143
Gross capacity factor**	Assume 90%

Raw cost data are in 2010$'s.

* Boiler conversion costs for manual controls are significantly less than seamless controls, but it is becoming increasingly common for boiler owners with manual controls to upgrade to seamless controls due to increased optimization. Conversion costs for multi-burner boilers, typically located at petrochemical plants & refineries, are significantly higher than seamless controls due to inherent complexities at facilities where these types of boilers are often found. Cost does NOT include boiler re-certification, which may be necessary due to state/local regulations or insurance requirements.

** Gross capacity factor accounts for loss of energy production due to problems in the gas collection system, problems with project equipment, weather related interruptions of the local utilities and shut-downs at the energy consumer end of the system.

RNG: Renewable Natural Gas Processing Plant	
Typical components include	- Blowers, compressors, piping controls, gas separators and dryers; - Pipeline interconnect equipment; - Pipeline to convey gas to project site or natural gas pipeline; and - Site work, building construction, utilities and total facility engineering, design and permitting. (Includes all equipment downstream of collection and flaring system.) Raw cost data for RNG processing, interconnect and pipeline costs provided by Energy Vision and The Hunter Group.
Installed capital cost of gas processing equipment for pipeline quality gas	$\$6{,}000{,}000 * e^{(0.0003*(ft^3/min)}$
Installed cost of interconnection equipment	\$400,000
Installed capital cost of pipeline	*For pipelines < 1 mile long:* \$600,000 *For pipelines ≥1 mile long:* \$1,000,000 * miles of pipeline
Initial pipeline interconnection fee	Varies by utility. User-specified amount.
Annual O&M cost (excluding electricity)	$(250 * ft^3/min)$ + 148,000
Electricity usage	0.009 kWh/ft^3
Ongoing pipeline interconnection fee	Varies by utility. Suggested default of \$2.50 per MMBtu of RNG injected.
RNG production rate (MMBtu/ft^3 LFG)*	[(1,012 Btu/ft^3 CH_4) * (% CH_4 in LFG) * (90% methane capture rate) * (million Btu/10^6 Btu)] = 0.0005 million Btu/ft^3 LFG with default 50% CH_4 in LFG
RNG production (GGE)*	(90% methane capture rate)* (% CH_4 in LFG) *(1,012 Btu/ft^3 CH_4)/ 111,200 Btu/GGE
Gross capacity factor**	Assume 93%

Note: Raw cost data are in 2019\$'s. Gas processing equipment costs were determined based on pressure swing adsorption and membrane separation technologies.

* Default methane capture rate is 90% but this can be changed by the user.

** Gross capacity factor accounts for loss of energy production due to problems in the gas collection system, problems with project equipment, weather related interruptions of the local utilities and shut-downs at the energy consumer end of the system.

CNG: Onsite CNG Production and Fueling Station	
Typical components include	- LFG-to-CNG conversion and conditioning unit; - Fueling station equipment (includes compressors, dispensers and storage tanks for all fill types -- fast, slow and combination of fast/slow); - Winterization equipment, if needed (includes heat tracing and insulation of hydrogen sulfide vessel and heated and insulated structure over other equipment); - Engineering and project management (includes site design, layout and permitting); and - Installation of all equipment, startup and training. (Includes all equipment downstream of collection and flaring system.)
Installed capital cost	$95,000 * (ft^3/min)^{0.6}$
Annual O&M cost for media and equipment replacement and parasitic load	$1.00/gasoline gallon equivalent (GGE)*
CNG production	[(1,012 Btu/ft^3 CH_4) * (% CH_4 in LFG) * (65% conversion efficiency)] / 111,200 Btu/GGE = 0.0030 GGE/ft^3 LFG with default 50% CH_4 in LFG
Gross capacity factor**	Assume 93%

Note: Raw cost data are in 2013$'s.

* To determine $/diesel gallon equivalent (DGE), divide $/GGE by 0.866.

** Gross capacity factor accounts for loss of energy production due to problems in the gas collection system, problems with project equipment and weather-related interruptions of the local utilities.

TUR: Standard Turbine-Generator Set	
Typical components include	- Gas compression and treatment (includes dehydration equipment, siloxane adsorbers and filtration); - Turbine and generator (includes exhaust silencers and all wiring and plumbing); - Electrical interconnect equipment; and - Site work, housings, utilities and total facility engineering, design and permitting. (Includes all equipment downstream of collection and flaring system.)
Installed capital cost	*For most situations:* [($2,340 * kW capacity) – (0.103 * (kW capacity)^2)] + $250,000 for interconnect *For [$2,340 – (0.103 * kW capacity)] < 1,015:* ($1,015 * kW capacity) + $250,000 for interconnect
Annual O&M cost (excluding energy)	$0.0144 * kWh generated/yr (before parasitic uses)
Parasitic loss efficiency	88% of capacity due to parasitic electrical needs of compression and treatment
Fuel use rate	13,000 Btu/kWh generated (HHV) (before parasitic uses)
Gross capacity factor*	Assume 93%

Note: Raw cost data are in 2008$'s.

* Gross capacity factor accounts for loss of energy production due to problems in the gas collection system, problems with project equipment, weather related interruptions of the local utilities and shut-downs at the energy consumer end of the system.

ENG: Standard Reciprocating Engine-Generator Set	
Typical components include	‣ Gas compression and treatment (includes dehydration equipment and filtration); ‣ Reciprocating engine and generator (includes motor controls, switch-gear, radiators, exhaust silencers and all wiring and plumbing); ‣ Electrical interconnect equipment; and ‣ Site work, housings, utilities and total facility engineering, design and permitting. (Includes all equipment downstream of collection and flaring system.)
Installed capital cost	[($1,300 * kW capacity) + $1,100,000] + $250,000 for interconnect
Annual O&M cost (excluding energy)	$0.025 * kWh generated/yr (before parasitic uses)
Parasitic loss efficiency	93% of capacity due to parasitic electrical needs of compression and treatment
Fuel use rate	11,250 Btu/kWh generated (HHV) (before parasitic uses)
Gross capacity factor*	Assume 93%

Note: Raw cost data are in 2013$'s.

* Gross capacity factor accounts for loss of energy production due to problems in the gas collection system, problems with project equipment, weather related interruptions of the local utilities and shut-downs at the energy consumer end of the system.

MTUR: Microturbine–Generator Set	
Typical components include	▸ Gas compression and treatment (includes dehydration equipment, siloxane adsorbers and filtration); ▸ Microturbine and generator (includes exhaust silencers and all wiring and plumbing); ▸ Electrical interconnect equipment; and ▸ Site work, housings, utilities and total facility engineering, design and permitting. (Includes all equipment downstream of collection and flaring system.)
Installed capital cost	$19,278 * (kW capacity)$^{0.6207}$
Annual O&M cost (excluding energy)	($0.0736 – (0.0094 * ln(kW capacity))) * kWh generated/yr (before parasitic uses), includes gas cleanup system O&M and microturbine overhauls
Parasitic loss efficiency	83% of rated capacity due to parasitic electrical needs of boost compressor and cooling water pumps, fans and dryer system
Fuel use rate	14,000 Btu/kWh generated (HHV) (before parasitic uses)
Gross capacity factor*	Assume 93%

Note: Raw cost data are in 2006$'s.

* Gross capacity factor accounts for loss of energy production due to problems in the gas collection system, problems with project equipment, weather related interruptions of the local utilities and shut-downs at the energy consumer end of the system.

SENG: Small Reciprocating Engine–Generator Set	
Typical components include	‣ Gas compression and treatment (includes dehydration equipment and filtration); ‣ Reciprocating engine and generator (includes motor controls, switch-gear, radiators, exhaust silencers and all wiring and plumbing; ‣ Electrical interconnect equipment; and ‣ Site work, housings, utilities and total facility engineering, design and permitting. (Includes all equipment downstream of collection and flaring system.)
Installed capital cost	$2,300 * kW capacity
Annual O&M cost (excluding energy)	$0.024 * kWh generated/yr (before parasitic uses)
Parasitic loss efficiency	92% of capacity due to parasitic electrical needs of compression and treatment
Fuel use rate	36 ft^3/kWh generated (before parasitic uses)
Gross capacity factor*	Assume 93%

Note: Raw cost data are in 2008$'s.

* Gross capacity factor accounts for loss of energy production due to problems in the gas collection system, problems with project equipment, weather related interruptions of the local utilities and shut-downs at the energy consumer end of the system.

CHPE: CHP Reciprocating Engine-Generator Set	
Typical components include	▸ Gas compression and treatment (includes dehydration equipment and filtration); ▸ Heat recovery exchangers; ▸ Reciprocating engine and generator (includes motor controls, switch-gear, radiators, exhaust silencers and all wiring and plumbing); ▸ Electrical interconnect equipment; ▸ Site work, housings, utilities and total facility engineering, design and permitting; ▸ Gas pipeline from compressor to engine; ▸ Water pipelines from engine to hot water user (assumes 2 lines for supply and return); and ▸ Circulation pump for water pipelines. (Includes all equipment downstream of collection and flaring system.)
Installed capital cost	($1,900 * kW capacity) + ($250,000 for interconnect) + ($63 * ft of gas pipeline) + ($106 * ft of trench for water pipelines) + ($12,000 for circulation pump)
Annual O&M cost (excluding energy)	$0.02 * kWh generated/yr (parasitic)
Parasitic loss efficiency	93% of capacity due to parasitic electrical needs of compression and treatment
Fuel use rate	11,250 Btu/kWh generated (HHV) (before parasitic uses)
Gross capacity factor*	Assume 93%
Hot water production	3,800 Btu/kWh (net) * % utilization of hot water potential

Note: Raw cost data are in 2008$'s.

* Gross capacity factor accounts for loss of energy production due to problems in the gas collection system, problems with project equipment, weather related interruptions of the local utilities and shut-downs at the energy consumer end of the system.

CHPT: CHP Turbine-Generator Set	
Typical components include	‣ Gas compression and treatment (includes dehydration equipment, siloxane adsorbers and filtration); ‣ Heat recovery exchangers; ‣ Turbine and generator (includes exhaust silencers and all wiring and plumbing); ‣ Electrical interconnect equipment; ‣ Site work, housings, utilities and total facility engineering, design and permitting; ‣ Gas pipeline from compressor to turbine; ‣ Steam pipelines from turbine to steam user (assumes 2 lines for supply and return); and ‣ Circulation pump for steam pipelines. (Includes all equipment downstream of collection and flaring system.)
Installed capital cost	*For most situations:* [($2,340 * kW capacity) – (0.103 * (kW capacity)^2)] + ($250,000 for interconnect) + ($355 * kW capacity, for heat recovery exchangers) + ($63 * ft of gas pipeline) + ($106 * ft of trench for steam pipelines) + ($12,000 for circulation pump) *For [$2,340 – (0.103 * kW capacity)] < 1,370:* ($1,370 * kW capacity) + ($250,000 for interconnect) + ($355 * kW capacity, for heat exchangers) + ($63 * ft of gas pipeline) + ($106 * ft of trench for steam pipelines) + ($12,000 for circulation pump)
Annual O&M cost (excluding energy)	$0.0144 * kWh generated/yr (before parasitic uses)
Parasitic loss efficiency	88% of capacity due to parasitic electrical needs of compression and treatment
Fuel use rate	13,000 Btu/kWh generated (HHV) (before parasitic uses)
Gross capacity factor*	Assume 93%
Steam production	5,500 Btu/kWh (net) * % utilization of steam potential

Note: Raw cost data are in 2008$'s.

* Gross capacity factor accounts for loss of energy production due to problems in the gas collection system, problems with project equipment, weather related interruptions of the local utilities and shut-downs at the energy consumer end of the system.

CHPM: CHP Microturbine-Generator Set	
Typical components include	▸ Gas compression and treatment (includes dehydration equipment, siloxane adsorbers and filtration); ▸ Heat recovery exchangers; ▸ Microturbine and generator (includes exhaust silencers and all wiring and plumbing); ▸ Electrical interconnect equipment; ▸ Site work, housings, utilities and total facility engineering, design and permitting; ▸ Gas pipeline from compressor to microturbine; ▸ Water pipelines from microturbine to hot water user (assumes 2 lines for supply and return); and ▸ Circulation pump for water pipelines. (Includes all equipment downstream of collection and flaring system.)
Installed capital cost	$(\$20{,}057 * (\text{kW capacity})^{0.6207}) + [(\$20{,}057 * (\text{kW capacity})^{0.6207}) * (0.06,$ for heat recovery exchangers)] + ($63 * ft of gas pipeline) + ($106 * ft of trench for water pipelines) + ($12,000 for circulation pump)
Annual O&M cost (excluding energy)	$0.0773 – 0.00987* ln(kW capacity)
Parasitic loss efficiency	83% of rated capacity due to parasitic electrical needs of boost compressor and cooling water pumps, fans and dryer system
Fuel use rate	14,000 Btu/kWh generated (HHV) (before parasitic uses)
Gross capacity factor*	Assume 93%
Hot water production	5,800 Btu/kWh (net) * % utilization of hot water potential

Note: Raw cost data are in 2008$'s.

* Gross capacity factor accounts for loss of energy production due to problems in the gas collection system, problems with project equipment, weather related interruptions of the local utilities and shut-downs at the energy consumer end of the system.

ECN: Economic Analysis

Economic Inputs:

Rows 4-25	These data are user-specified inputs that are retrieved from the INP-OUT worksheet.
Row 28	Initial IRR estimate used by Microsoft® Excel's IRR calculation function.
Row 29	LFG heat content calculated using user-specified methane heat content.

Inputs Calculated from Other Worksheets:

Rows 33-42	These data are the results calculated on other worksheets and brought to the ECN worksheet for use in the economic analysis.

Economic Analysis (Rows 45 to 90):

Row 45	**Year of operation**	The chronological year in the life of the project. The zero year is the year of construction and year 1 is the first year of operation.
Row 46	**Revenue**	The revenues from selling gas, electricity, CNG or CHP hot water/steam.
Row 47	**Direct-use or RNG sales**	*For Direct-use*: (ft^3 LFG sold)*(Btu/ft^3)*(million Btu/10^6 Btu)*($/million Btu)*(price escalation equation[a]); *For RNG*: (RNG produced (million Btu)*($/million Btu)*(price escalation equation[a])
Row 48	**Electricity sales**	(kWh electricity produced)*($/kWh)*(price escalation equation[a])
Row 49	**CNG sales**	(GGE produced)* ($/GGE)*(price escalation equation[a])
Row 50	**CHP hot water/steam sales**	(million Btu water/steam produced)*($/million Btu)*(price escalation equation[a])
Row 51	**Operating cost**	The operating and maintenance costs for the project, calculated on the various technology worksheets.
Row 52	**Greenhouse gas credit**	(avoided CO_2 emissions-$MTCO_2E$)*($/$MTCO_2E$)*($10^6$ $MTCO_2E$/ $MMTCO_2E$) This credit can include direct methane emissions as well if indicated in the ***Optional User Inputs*** table of the INP-OUT worksheet.
Row 53	**Renewable electricity credit**	(kWh electricity sold)*($/kWh) Provides credits to LFG electricity projects that utilize tradable renewable energy certificates (TRCs) or "green tags."
Row 54	**Renewable fuel credit**	(GGE produced)*($/gal) Provides credits to CNG or RNG vehicle fuel projects including projects that use Renewable Identification Numbers (RINs) where a gallon of renewable fuel produced in or imported into the United States receives a credit.

ECN: Economic Analysis

Economic Analysis (continued)

Row 55	**Gas royalty**	(ft^3 LFG utilized)*(Btu/ft^3)*(million Btu/10^6 Btu)*(royalty $/million Btu) A royalty paid to landfill for use of LFG.
Row 57	**Down payment**	Portion of capital cost not financed. (total capital cost)*(% down payment)
Row 58	**Construction grant**	A government cash grant towards project capital costs.
Row 59	**Loan (principal)**	The levelized annual loan payment – calculated using Microsoft® Excel's payment function, based on interest rate, loan period and amount borrowed.
Row 60	**Loan (interest)**	Annual interest on remaining loan balance (principle). (total capital cost – down payment)*(% interest rate)
Row 61	**Equity payment**	Amount of annual loan payment applied to principle. (annual loan payment) – (annual interest)
Row 62	**Principal remaining**	Unpaid loan principle. (previous year principle) – (previous year equity payment)
Row 63	**Depreciation**	The straight line depreciation of capital cost for tax purposes. (total capital cost) / (project life-years)
Row 65	**Tax liability**	Sum of revenues minus expenses. (direct or RNG sales) + (electricity sales) + (CHP hot water/steam sales) + (greenhouse gas credit) + (renewable electricity credit) – (operating cost) – (gas royalty) – (interest) – (depreciation)
Row 66	**Tax before credit**	Estimation of base tax before energy credits. (tax liability)*(marginal tax rate)
Row 67	**Tax credit**	Sum of energy credits. (LFG utilization credit) + (electricity generation credit) + (RNG production credit)
Row 68	**Net tax**	Sum of taxes minus tax credits. (tax before credit) – (tax credit)
Row 70	**Net income**	Sum of revenues less operating costs. (direct or RNG sales) + (electricity sales) + (CHP hot water/steam sales) + (greenhouse gas credit) + (renewable electricity credit)– (operating cost) – (gas royalty) – (interest) – (depreciation) – (net tax)
Row 73	**Cash flow**	Sum of annual cash flows. (net income) – (down payment) + (construction grant) + (depreciation) – (equity payment)
Row 75	**Internal rate of return**	The return on investment based on cash flow. (calculated using Microsoft® Excel's "IRR" function based on cash flow)

ECN: Economic Analysis

Economic Analysis (continued)

Row 77	**Cumulative cash flow**	The sum of cash flows to-date. (previous year's cumulative cash flow) + (present year cash flow)
Row 79	**Simple payback (years)**	The years of operation required for the cumulative cash flow to become a positive value, based on an evaluation of values in Row 79. This parameter is used only as an error-checking tool.
Row 82	**Present value of cash flow**	Present value (PV) of the year's cash flow based on discount rate. (cumulative cash flow) / (compounded discount rate)
Row 85	**NPV**	The net present value (NPV) or initial monetary value that is equivalent to the sum of the cash flows, based on the discount rate. This value is determined from the cumulative PV (Row 88) at the end of the project life.
Row 88	**Cumulative present value**	The sum of the PVs of cash flow to-date. (previous year's cumulative PV) + (present year PV)
Row 90	**Years to breakeven**	The years of operation that are required for the cumulative PV to become a positive value, based on an evaluation of values in Row 90.

Optimization for Calculating Initial Product Price Needed to Achieve Financial Goals:

Rows 94-148 These data are used to calculate the initial product price required to achieve the financial goals of the project. The equations in rows 103-148 duplicate the structure of Rows 45-90 and are used to test various initial product prices for the purpose of converging on a net present value of $0.

Other Economic Assumptions:

Salvage Value and Decommissioning Cost

For simplicity, LFGcost-Web does not consider the salvage value of the equipment nor the costs to recover the site, at the end of the project life. Due to the nature of LFG energy projects, these costs are mutually off-setting and generally result in a minimal impact to the overall economic evaluation of the typical LFG energy project.

[a] Escalation equations use a formula of $[1 + ((\% \text{ escalation after year } 1)/100)]^{(\text{year of calculation} - 1)}$

BUDGET-ENG: Allocation of Recip. Engine Costs for Economic Benefits[a]

This worksheet assigns the typical components of a reciprocating engine project (excluding costs of gas collection and control system infrastructure) from the ENG worksheet to one of six categories: state/local labor, labor from outside the state, state/locally manufactured materials, materials manufactured outside the state, state/local distributor fees or fees paid to distributors outside of the state. The list below shows how the reciprocating engine project costs were assigned to these six categories.

<u>Construction Phase (one-time costs)</u>

Gas cleanup/compression unit purchase costs – 10% of overall combined engine/generator/skid costs

- 94% national manufacturer revenue
- 6% national distributor fee

Engine-generator unit purchase costs – 50% of overall combined engine/generator/skid costs

- 89% national manufacturer revenue
- 11% state-wide distributor fee

Installation costs for clean-up skid and Engine-Generator – 40% of overall combined engine/generator/skid costs

- 5.4% national engineering and management labor for clean-up skid ($167/hr, loaded with benefits)
- 62.5% state-wide installation labor (6.1% for skid materials and 56.4% for engine/generator materials) ($140/hr, loaded with benefits)
- 32% state-wide installation materials (28% for engine/generator materials and 4% for skid materials)

Electrical interconnect costs

- 75% skid unit capital cost
  - 64% national manufactured materials
  - 11% state-wide distributor fee
- 25% installation cost
  - 17% state-wide engineering, management, installation labor ($167/hr, loaded with benefits)
  - 8% state-wide manufactured installation materials

<u>Annual Operating Costs</u>

- 5% national proprietary materials (skid components)
- 45% common O&M materials (oil filters, lubricants, wiring)
  - 34% national manufacturer materials
  - 11% state-wide distributor fee on materials
- 50% state-wide labor (tuning wellfields and O&M of project equipment), salary of $116,000 per year. Considering benefits of 29.8%, the loaded salary is $165,000 in year 2020$. Labor is escalated using the general inflation rate in the model.

This worksheet then assigns labor and purchased materials to the BEA 2018 RIMS II multipliers that are most representative of the materials used in the construction of an LFG energy project. A complete list of multipliers is shown in Appendix F.

BUDGET-ENG: Allocation of Recip. Engine Costs for Economic Benefits

Allocation of Recip. Engine Costs for Economic Benefits (continued)

For evaluating the state and local economic benefits of reciprocating engine projects, the multipliers were assigned as follows:

Construction Phase

Gas clean-up skid installation materials consist of electrical connections to connect the skid to a source of energy to power the compressor system. These are assigned to the Electrical Equipment and Appliance Manufacturing multiplier.
Local labor is assigned to the Households multiplier.
Distributor fees are assigned to the Wholesale Trade multiplier.

Operation and Maintenance Phase

Distributor fees are assigned to the Wholesale Trade multiplier.
Local labor is assigned to the Households multiplier.

This worksheet also estimates the number of state-wide direct jobs created from the design and installation (cell F11), or operation (cell F34) of an LFG energy project. The number of jobs, in terms of full-time equivalents (FTE), is estimated using loaded earnings most typical for staff used directly in LFG energy projects. For design and installation, state-wide labor rates ranged from $95 to $167 per hour, depending on whether the labor was for engineers, skid installation or generator installation. This analysis assumes 1,850 billable hours per year, equating to 1 job per $175,800 to $309,000 of loaded earnings in 2020$. For O&M, the labor rate was assumed to be $116,000 per year, or $165,000 per year fully loaded in 2020$. Labor rates were escalated using the general inflation rate supplied in cell D44 of the INP-OUT sheet.

[a] The economic and job benefits for reciprocating engine projects are limited to the energy recovery portion of the project and exclude the economic and job benefits associated with the construction and operation of a gas collection system.

BUDGET-DIR: Allocation of Direct-Use Project Costs for Economic Benefits[a]

Similar to the BUDGET-ENG worksheet, this worksheet assigns the typical components of a direct-use project (excluding costs of gas collection and control system infrastructure) from the DIR worksheet to one of seven categories: state/local labor, labor from outside the state, state/locally manufactured materials, materials manufactured outside the state, state/local distributor fees, fees paid to distributors outside of the state and electric utilities. The list below shows how the direct-use project costs were assigned to these seven categories.

<u>Construction Phase (one-time costs)</u>
Gas cleanup/compression unit costs

- 75% skid unit capital cost
  - 69% nationally manufactured materials
  - 6% national distributor fee

- 25% installation cost
  - 8% state-wide manufactured materials
  - 8% national engineering and management labor ($167/hr, loaded with benefits)
  - 9% state-wide installation labor ($95/hr, loaded with benefits)

Pipeline costs

- 25% pipeline capital cost
  - 21% national manufactured materials
  - 4% state-wide distributor fee for materials
- 75% installation cost
  - 7% state-wide manufactured materials
  - 11% national engineering and management labor
  - 57% state-wide installation labor ($97/hr, loaded with benefits)

<u>Annual Operating Costs</u>

Materials and Labor

- 5% national proprietary manufactured materials (skid components)
- 45% common O&M materials (oil filters, lubricants, wiring)
  - 34% national manufactured materials
  - 11% state-wide distributor fee
- 50% state-wide labor (tuning wellfields and O&M of project equipment, $55,000/year). Considering benefits of 29.8%, the loaded salary is $78,300 in year 2020$. Labor is escalated using the general inflation rate in the model.

Utilities (electricity to operate compression skid)

- 100% purchased state-wide electricity

This worksheet then assigns labor and purchased materials to the BEA 2018 RIMS II multipliers that are most representative of the materials used in an LFG energy project. A complete list of multipliers is shown in Appendix F.

BUDGET-DIR: Allocation of Direct-Use Project Costs for Economic Benefits[a]

Allocation of Direct-Use Project Costs for Economic Benefits (continued)

For evaluating the state and local economic benefits of direct-use projects, the multipliers were assigned as follows:

Construction Phase
Gas clean-up skid installation materials consist of electrical connections to connect the skid to a source of energy to power the compressor system. These are assigned to the Electrical Equipment and Appliance Manufacturing multiplier.
Distributor fees are assigned to the Wholesale Trade multiplier.
Local labor is assigned to the Households multiplier.

Pipeline installation materials include soil aggregate materials needed to properly line and re-surface the trench. These are assigned to the Other Nonmetallic Mineral Mining and Quarrying multiplier.

Operation and Maintenance Phase
Distributor fees are assigned to the Wholesale Trade multiplier.
Local labor is assigned to the Households multiplier.
Electricity purchased is assigned to the Electric Power Generation, Transmission and Distribution multiplier.

This worksheet also estimates the number of state-wide direct jobs created from the design and installation (cell F16), or operation (cell F31) of an LFG energy project. The number of jobs, in terms of FTE, is estimated using loaded earnings most typical for staff used directly in LFG energy projects. For design and installation, state-wide labor rates ranged from \$95 to \$97 per hour, depending on whether the labor was for engineers, site operators or equipment installation. This analysis assumes 1,850 billable hours per year, equating to 1 job per \$175,800 to \$179,600 of loaded earnings in 2020\$. For O&M, the labor rate was assumed to be \$55,000 per year, or \$78,300 per year fully loaded in 2020\$. Labor rates were escalated using the general inflation rate supplied in cell D44 of the INP-OUT sheet.

[a] The economic and job benefits for direct-use projects are limited to the energy recovery portion of the project and exclude the economic and job benefits associated with the construction and operation of a gas collection system.

BUDGET-RNG: Allocation of RNG Costs for Economic Benefits[a]

This worksheet assigns the typical components of an RNG project (excluding costs of gas collection and control system infrastructure) from the RNG worksheet to one of eight categories: state/local labor, labor from outside the state, state/locally manufactured materials, materials manufactured outside the state, state/local distributor fees, electric utilities, gas utilities and insurance. The list below shows how the RNG project costs were assigned to these eight categories.

Construction Phase (one-time costs)

Gas processing equipment – 60% of overall capital equipment costs

100% national manufacturer revenue

Installation costs for gas processing equipment – 40% of overall capital equipment costs

14% state installation labor (half of which is assumed to be trade labor, $95/hr, loaded with benefits and the other half engineering/management labor, $167/hr, loaded with benefits)
13% national engineering and management labor ($167/hr, loaded with benefits)
13% state purchased materials

Pipeline/Interconnection

Interconnection costs

60% interconnection capital cost
- 56% national manufactured materials
- 4% state-wide distributor fee for materials

40% state installation labor cost (half of which is assumed to be trade labor, $97/hr, loaded with benefits and the other half engineering/management labor, $167/hr, loaded with benefits)

Pipeline installation costs

25% pipeline capital cost
- 21% national manufactured materials
- 4% state-wide distributor fee for materials

75% installation cost
- 7% state-wide manufactured materials
- 11% national engineering and management labor
- 57% state-wide installation trade labor ($97/hr, loaded with benefits)

Utilities

100% of pipeline interconnection fee (if entered by user), this is an optional user input

Annual Operating Costs

Materials, Labor and Insurance

For projects with design flow rates of 1,000 scfm but less than 4,000 scfm, the labor is estimated at two FTE positions, each with a starting salary of $55,000. Considering benefits of 29.8%, the loaded salary for these two positions is $156,700 in year 2020$. Labor is escalated using the general inflation rate in the model.

For projects with design flow rates of 4,000 scfm up to the maximum size suggested by the model of 6,000 scfm, the labor is estimated at three FTE positions, each with a starting salary of $55,000. Considering benefits of 29.8%, the loaded salary for these three positions is $235,000. Labor is escalated using the general inflation rate in the model.

BUDGET-RNG: Allocation of RNG Costs for Economic Benefits[a]

Allocation of RNG Project Costs for Economic Benefits (continued)

Additional labor may be needed if RNG projects also incorporate full-time wellfield operators as part of the project operation, but that labor is not included in the economic impact analysis of this model. After labor has been subtracted from the total estimated O&M costs, the remainder of the O&M costs for a given project size are assigned as follows:

10% national proprietary manufactured materials (skid components or media that may need to be replaced)
20% state purchased O&M materials (oil filters, lubricants, wiring)
- 16% national manufactured materials
- 4% state-wide distributor fee

30% national labor for professional services labor ($167/hr, loaded with benefits), certification/audit services for environmental credits, legal, laboratory testing fees to ensure RNG meets pipeline specifications)

40% insurance premiums (assumed to be state-level payments given state regulation of insurance markets)

Utilities

100% of the electricity cost is purchased state-wide electricity for electricity to operate gas processing equipment and pipeline injection
100% of the annual pipeline injection tariff is purchased state-wide natural gas distribution fees

This worksheet then assigns labor and purchased materials to the BEA 2018 RIMS II multipliers that are most representative of the materials used in the construction of an LFG energy project. A complete list of multipliers is shown in Appendix F.

For evaluating the state and local economic benefits of RNG projects, the multipliers were assigned as follows:

Construction Phase

- *Gas processing equipment skid installation materials* consist of electrical connections to connect the skid to a source of energy to power the compressor system. These are assigned to the Electrical Equipment and Appliance Manufacturing multiplier.
- *Distributor fees* are assigned to the Wholesale Trade multiplier.
- *Local labor* is assigned to the Households multiplier.
- *Pipeline installation materials* include soil aggregate materials needed to properly line and re-surface the trench. These are assigned to the Other Nonmetallic Mineral Mining and Quarrying multiplier.
- *RNG pipeline interconnection fee* if entered by the user is assigned to the Natural Gas Distribution multiplier.

Operation and Maintenance Phase

Distributor fees are assigned to the Wholesale Trade multiplier.
Local labor is assigned to the Households multiplier.
Electricity purchased is assigned to the Electric Power Generation, Transmission and Distribution multiplier.
RNG pipeline injection fee is assigned to the Natural Gas Distribution multiplier.

BUDGET-RNG: Allocation of RNG Costs for Economic Benefits[a]

Allocation of RNG Project Costs for Economic Benefits (continued)

This worksheet also estimates the number of state-wide direct jobs created from the design and installation (cells F17 and F24), or operation (cell F43) of an LFG energy project. The number of jobs, in terms of FTE, is estimated using loaded earnings most typical for staff used directly in LFG energy projects. State-wide labor rates ranged from \$89 to \$167 per hour, depending on whether the labor was for engineers, site operators or equipment installation.

For design and installation, as well as national specialty labor during O&M that is expected to be contracted out, this analysis assumes 1,850 billable hours per year, equating to 1 job per \$175,800 to \$309,000 of loaded earnings in 2020\$. For local O&M, the labor rate was assumed to be \$55,000 per year, or \$78,300 per year fully loaded in 2020\$. These are full-time positions and the number of people depends on the size of the project. Labor rates were escalated using the general inflation rate supplied in cell D44 of the INP-OUT sheet.

[a] The economic and job benefits for RNG projects are limited to the energy recovery portion of the project and exclude the economic and job benefits associated with the construction and operation of a gas collection system.

ECON-BEN SUMMARY: Economic Benefits and Job Creation Summary[a]

This worksheet summarizes the jobs, earnings and expenditures that result from a direct-use, reciprocating engine or RNG LFG energy project.

The first set of tables (rows 7-15) summarize the total economic benefits resulting from a direct-use, reciprocating engine or RNG project (depending upon which type of project the user is evaluating), excluding any benefits from the construction and operation of the gas collection and control system infrastructure). The left table presents benefits during the project construction phase (a one-time economic benefit) and the right table presents annual benefits from the O&M of a project.

Total economic benefits have three components: direct, indirect and induced.

- **Direct effects** result from onsite jobs and new purchases from state and local businesses that are required to build and operate the project.
- **Indirect effects** occur as those state and local businesses spend their new revenue on supplies or to pay their employees.
- **Induced effects** result when employees spend their paychecks and, for larger projects, when people migrate to the area.

Each layer of spending generates new income to firms and families in the region and to the overall national economy. The first set of tables show the benefits for a specific state in which the project was constructed, if the user selected a state on the BUDGET-DIR, BUDGET-ENG or BUDGET-RNG sheet. It also shows the benefits for states representing a low, median and high range of output and job creation.

The second set of tables (rows 20-30) provide a detailed summary of the relative contributions of direct economic benefits compared to economic "ripple effects" benefits.

Estimates are based on BEA 2018 RIMS II multipliers that are most representative of the materials used in an LFG energy project. BEA does not endorse any resulting estimates and/or conclusions about the economic impact of a proposed change on an area.

[a] The economic and job benefits for direct-use, reciprocating engine and RNG projects are limited to the energy recovery portion of the project and exclude the economic and job benefits associated with the construction and operation of a gas collection system.

Appendix A:
Default Value Documentation

Appendix A: Default Value Documentation

Loan Lifetime

The loan lifetime is assumed to begin during the year of project design and construction. It is common for project loan periods to be limited to half or two-thirds of the equipment lifetime to assure that the loan is repaid before the project ends. Since much of the equipment used in LFG energy projects has a projected lifetime of 15 years, the default loan lifetime is set to 10 years.

See Table D-1 of Appendix D (Evaluating Local Government-Owned Projects) for recommended default assumptions for municipalities using budgeted funds or public bonds to finance projects.

Interest Rate

Interest rates fluctuate with economic conditions and many unforeseen factors, making them very difficult to forecast. The default interest rate is based on the 5-year average value of the Moody Corporate AAA and BAA bond rates published by the Federal Reserve. The 5-year average rate of 3.8% for 2018-2022 is rounded to 4% for the default rate.

For projects owned by municipalities, the recommended interest rate in prior iterations of this model was based on the 5-year average value of the State & Local Bond Rates published by the Federal Reserve. Since these data were discontinued in 2016, users can obtain updated rates for municipal bonds from Bloomberg. As of May 25, 2023, the average municipal bond rate for the 10- and 30-year yields is 3.91%. This is rounded to 4% for the recommended rate shown in Table D-1 of Appendix D (Evaluating Local Government-Owned Projects). Bloomberg market reports can be downloaded at https://www.bloomberg.com/markets/rates-bonds/government-bonds/us.

General Inflation Rate

The general inflation rate fluctuates with economic conditions and many unforeseen factors, making it very difficult to forecast. The default inflation rate is based on the 5-year average annual increase in the Consumer Price Index (CPI). The 5-year average annual CPI rate increase of 3.6% for 2018-2022 is rounded to 4% for the default rate. Users can obtain up-to-date CPI rates from the U.S. Department of Labor at https://www.bls.gov/cpi/.

Equipment Inflation Rate

The *Chemical Engineering* (*CE*) Plant Cost Index was used to determine the default equipment inflation rate. The average annual cost increase for the 5-year period of 2018-2022 was 8.2%. This rate was rounded to 8% for the LFGcost-Web default equipment inflation rate. Users can obtain up-to-date *CE* plant cost indices from the *Chemical Engineering* magazine published by Chemical Week Publishing, LLC at https://www.chemengonline.com/.

Marginal Tax Rate, Discount Rate and Down Payment

The default parameters for corporate marginal tax rate, discount rate and down payment of 21%, 9% and 20%, respectively, are based on recent LFG energy project experience with commercial projects. Corporate discount rates are commonly 2% to 3% higher than interest rates and 7% to 8% higher than inflation rates.

Projects owned by municipalities will generally experience different values for these parameters. Municipal tax rates are generally zero percent and municipalities may use a discount rate of zero percent for municipal projects. Municipalities tend to fund a project from municipal revenue, resulting in a down payment of 100%. See Table D-1 of Appendix D (Evaluating Local Government-Owned Projects) for recommended default assumptions for municipalities using budgeted funds or public bonds to finance projects.

Landfill Gas Production Prices

LMOP reviewed the EIA *Annual Energy Outlook 2023*, which forecasted a 2024-2025 average Henry Hub natural gas price of $3.78 per million Btu. The current natural gas price is depressed as a result of abundant domestic supply and efficient methods of production. Based on Smith Gardner's experience with LFG energy contracts, LFG pricing can be discounted between 15 and 30 percent, or more, from the Henry Hub natural gas delivery price (or other appropriate index based on the location of the project), with a defined price floor and ceiling. The default value for LFG is estimated to be $2.65 per million Btu. Users can obtain current *Annual Energy Outlook* prices at https://www.eia.gov/outlooks/aeo/data/browser/.

Electricity Generation Prices

The *Annual Energy Outlook 2023* forecasted electricity generation prices to be 6.6 cents per kWh in 2024. This default price represents the base electricity price, excluding any incentives. A list of regional generation prices from *Annual Energy Outlook 2023* by electricity market module, is available in the REGIONAL PRICING worksheet. The forecasted regional prices for 2024 range from 3.1 to 11.5 cents per kWh, should users want to select a regional generation price instead of the national average default value. Users may also have more precise pricing estimates from their local grid operators.

CHP Hot Water/Steam Production Prices

The average market price for hot water/steam sold by LFG energy CHP projects is estimated to be $4.73 per million Btu. This price is estimated from the $3.78 per million Btu natural gas price divided by a boiler efficiency of 80%.

Renewable Natural Gas Production Prices

LMOP based the RNG price on the *Annual Energy Outlook 2023*. As stated above, the report forecasts a 2024-2025 average natural gas price of $3.78 per million Btu. Based on Energy Vision's experience with LFG energy contracts, LFG pricing of RNG injected into the pipeline is typically pegged to 70-85% of natural gas spot prices in the region of the project. The default value is set at a value of $2.65 per million Btu for compressed and conditioned LFG.

CNG Production Prices (for onsite CNG fueling stations)

According to the U.S. DOE Alternative Fuels Data Center, the average CNG price between 2017 and September 2022 was $2.27 per gasoline gallon equivalent (GGE). LFGcost-Web uses a default price of $2.27 per GGE, which represents the base CNG purchase price, excluding any incentives. Users can obtain up-to-date CNG prices from U.S. DOE at https://www.afdc.energy.gov/fuels/prices.html.

Electricity Purchase Prices

The default price paid by landfills for electricity, when they do not produce their own electricity, is assumed to be 10.3 cents per kWh. The 2024 average national electricity price paid by industrial and commercial consumers as forecasted in the *Annual Energy Outlook 2023*, is 8.1 and 12.5 cents per kWh, respectively. The average of these two prices is 10.3 cents per kWh. A list of average regional purchase prices, by electricity market module, is available in the REGIONAL PRICING worksheet should users want to select a regional purchase price instead of the national average default value. Users may also have more precise pricing estimates from their current electricity bills.

Annual Product and Electricity Purchase Price Escalation Rates

In the *Annual Energy Outlook 2023,* EIA predicted prices for electricity generation will decrease by 7.0% in years 2024-2026. The average escalation rate of real energy prices for electricity products sold by landfills was assumed to be -7.0%.

For direct-use, boiler retrofit and RNG projects, EIA predicted that commercial natural gas prices will decrease by an average rate of 6.4% in years 2024-2026, which was used as the basis for the escalation rate for these project types.

EIA predicted that natural gas for transportation prices will decrease by 5.8% in years 2024-2026, which was used as the basis for a -5.8% escalation rate for CNG product prices.

For electricity purchased by landfills, the EIA predicted commercial electricity prices will decrease by 1.5% and industrial electricity prices will decrease by 3.5% in years 2024-2026. The average decrease of these products is 2.5%, which was used as the basis for the escalation rate for purchased electricity.

EIA projections show that during the 15-year period from 2022 through 2037, electricity generation prices decrease through ~2028, and then are relatively flat with some years showing a negative rate of change compared to the preceding year while others show a slightly positive rate of change.[1]

EIA predicted in the *Annual Energy Outlook 2023* that natural gas will experience increases in production in all cases over the projection period, which will support increasing domestic consumption and exports.[2] EIA projections show that during the 15-year period from 2022 through 2037, natural gas delivery prices for gas used in the transportation sector will decline.[3]

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1 U.S. Energy Information Administration. Annual Energy Outlook 2023. Electric Power Projections by Electricity Market Module Region. Accessed March 20, 2023. https://www.eia.gov/outlooks/aeo/data/browser/#/?id=62-AEO2023&region=5-0&cases=ref2023&start=2022&end=2037&f=A&linechart=~~~~~~~~~~~~ref2023-d020623a.126-62-AEO2023.5-0~ref2023-d020623a.127-62-AEO2023.5-0~ref2023-d020623a.128-62-AEO2023.5-0&map=&ctype=linechart&sourcekey=0.

2 U.S. Energy Information Administration. Annual Energy Outlook 2023. Issues in Focus: Inflation Reduction Act Cases in the AEO2023. Accessed March 20, 2023. https://www.eia.gov/outlooks/aeo/IIF_IRA/.

3 U.S. Energy Information Administration. Annual Energy Outlook 2023. Natural Gas Supply, Disposition, and Prices. Accessed March 20, 2023. https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2023&cases=ref2023&sourcekey=0.

Appendix B:
Common Abbreviations

Appendix B: Common Abbreviations

AP-42	EPA's Compilation of Air Pollutant Emission Factors
AEO	Annual Energy Outlook
Btu	British thermal units
CE	*Chemical Engineering*
CHP	combined heat and power
CNG	compressed natural gas
CO_2	carbon dioxide
CPI	Consumer Price Index
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
ft	feet
ft^3	cubic foot / cubic feet
gal	gallon
GHG	greenhouse gas
GWP	global warming potential
HDPE	high density polyethylene
HHV	higher heating value
hr	hour
IRR	internal rate of return
k	methane generation rate constant
kW	kilowatt
kWh	kilowatt-hour
L_o	potential methane generation capacity of waste
lb	pound
LFG	landfill gas
LMOP	Landfill Methane Outreach Program
MHz	megahertz
mi	mile
min	minute
MMBtu	million British thermal units
$MTCO_2E$	metric tons of carbon dioxide equivalents
$MMTCO_2E$	million metric tons of carbon dioxide equivalents

MSW	municipal solid waste
MT	metric ton
MW	megawatt
NPV	net present value
NSPS/EG	New Source Performance Standards/Emission Guidelines for MSW Landfills
O&M	operation and maintenance
PV	present value
RNG	renewable natural gas
TRCs	tradable renewable certificates
yr	year

Appendix C:
Evaluating Projects with
Multiple Equipment and/or Start Dates

Appendix C: Evaluating Projects with Multiple Equipment and/or Start Dates

LFG energy projects with multiple equipment and/or start dates can also be evaluated using LFGcost-Web. These complex LFG energy projects may include: dual projects (i.e., combining an engine with a direct-use project), staggered projects (e.g., installing an engine early in the life of the landfill and adding additional engines as the gas volume increases) and back-to-back projects (e.g., replacing an engine at the end of its 15-year life with a new engine). The general approach to evaluating these types of complex LFG energy projects is to evaluate each project component individually. If each project component, such as one engine, has a positive NPV then the overall project will also have a positive NPV. The following discussion addresses how to set up the individual component evaluations in LFGcost-Web and how to interpret the results produced by LFGcost-Web.

Required User Inputs – When entering landfill information into the ***Required User Inputs*** table, enter the standard landfill information that applies to the entire landfill. For the project information inputs (e.g., *LFG energy project type*, *Year LFG energy project begins operation*), enter the information that applies only to the specific project component that is being evaluated. For example, staggered and back-to-back project components will each have a different project start year. Model users should generally decline the required input to "include collection and flaring costs" in the evaluation. If users want to include the collection and flaring costs, this option should be selected only for the first project component to be installed. The evaluations of all subsequent components should decline to include the collection and flaring costs.

Optional User Inputs – All inputs in this section should be specific to the project component being evaluated. When entering the *LFG energy project size*, users **must** select the user-defined option, "Defined by user". On the next line, users must enter the *Design flow rate* for the project component being evaluated. The optional input data relating to the landfill itself (e.g., *Average depth of landfill waste* and *Landfill gas collection efficiency*) should apply to the overall landfill, and therefore should remain the same for each project component. All other information entered in this data input section should apply only to the project component being evaluated.

Outputs – After completing the required and optional user inputs, the economic evaluation of the project component appears in the ***Outputs*** table. The output values *Total lifetime amount of methane collected and destroyed* and *Average annual amount of methane collected and destroyed* apply to the entire landfill. All other output values, such as *GHG value of total lifetime amount of methane utilized in energy project* or *Internal rate of return*, apply only to the project component being evaluated. It is important to note that *Total installed capital cost for year of construction* and *Net present value at year of construction* are presented in terms of the construction year's actual dollars and *Annual costs for initial year of operation* are presented in terms of actual dollars for the year the LFG energy project begins operation. Therefore, the NPV of multiple project components will be in terms of different years' dollars and cannot be summed to obtain an accurate total project NPV.

Checking the integrity of the complex project component evaluation – After an LFGcost-Web evaluation has been conducted for each project component, a check must be made to ensure that the net capacity for the project components does not exceed the capacity of the landfill. This integrity check can be conducted easily using LFGcost-Web's graphical output in the CURVE worksheet. Model users should compile the graphs generated by LFGcost-Web for each component to confirm that the net gas use in any given year does not exceed the gas output of the landfill. Figure C-1 illustrates how graphs from three LFG energy project components can be manually compiled by users to confirm that the components do not exceed the LFG generation capacity. Figures C-1A, C-1B and C-1C are the curves generated by LFGcost-Web for each individual project component – A, B and C, respectively – compiled in Figure C-1. In this example, the size of project components B and/or C might be increased by as much as 50 percent and not exceed the gas generation potential of the landfill.

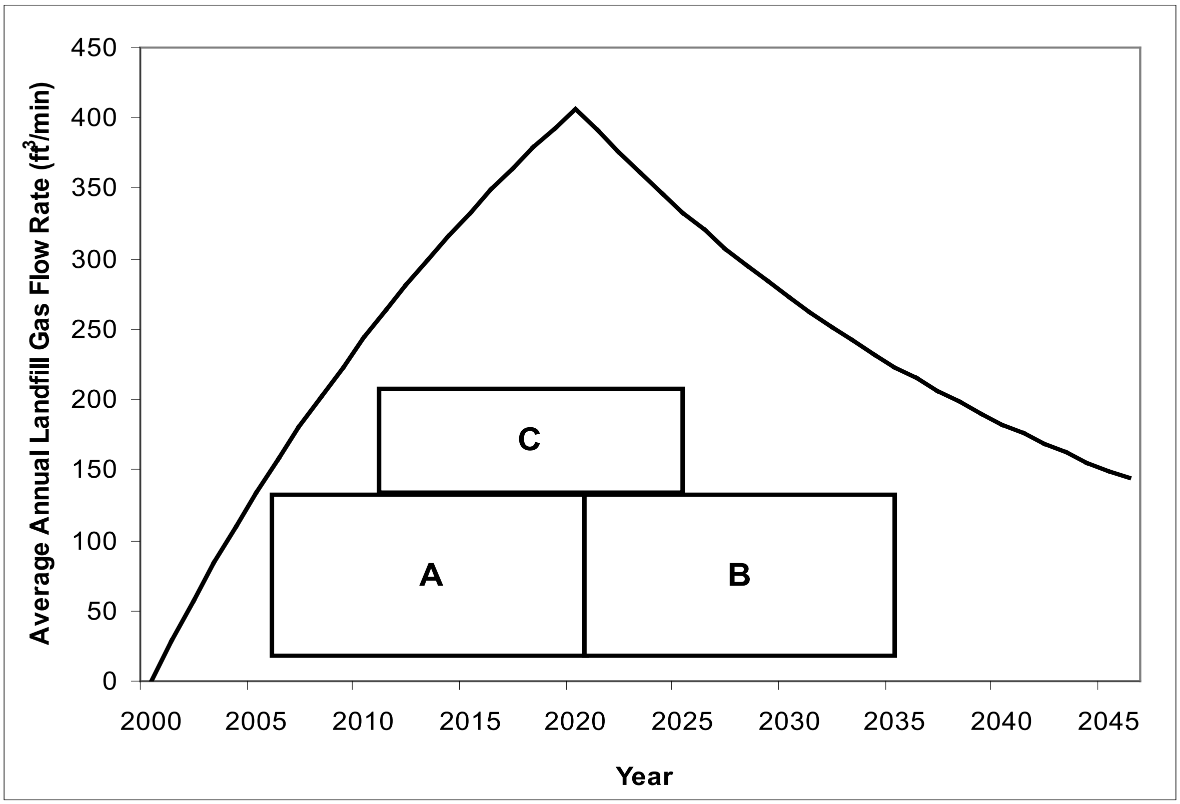

Figure C-1. Example of a project with multiple equipment and start dates

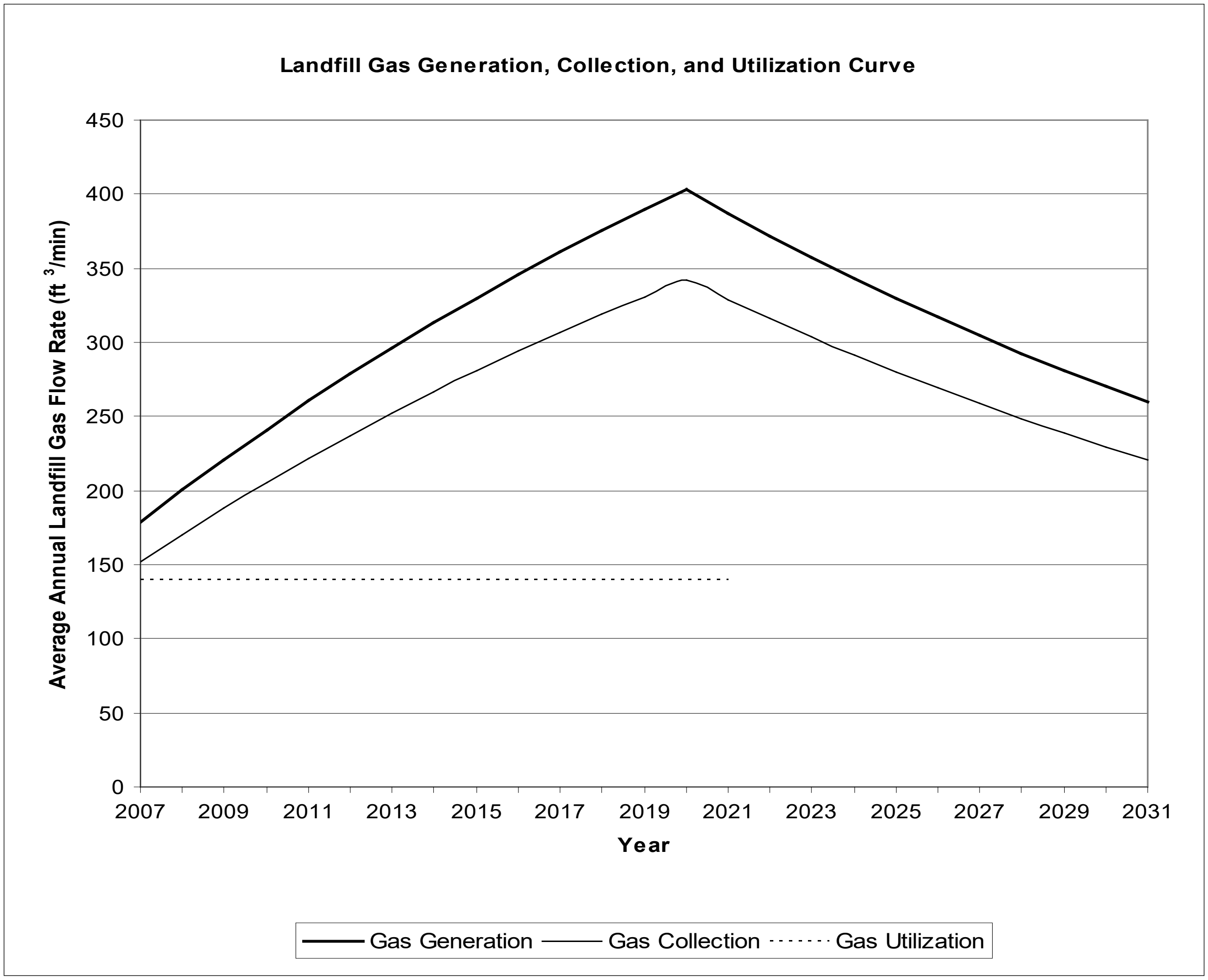

Figure C-1A. Example of an LFG generation, collection and utilization curve for project component A

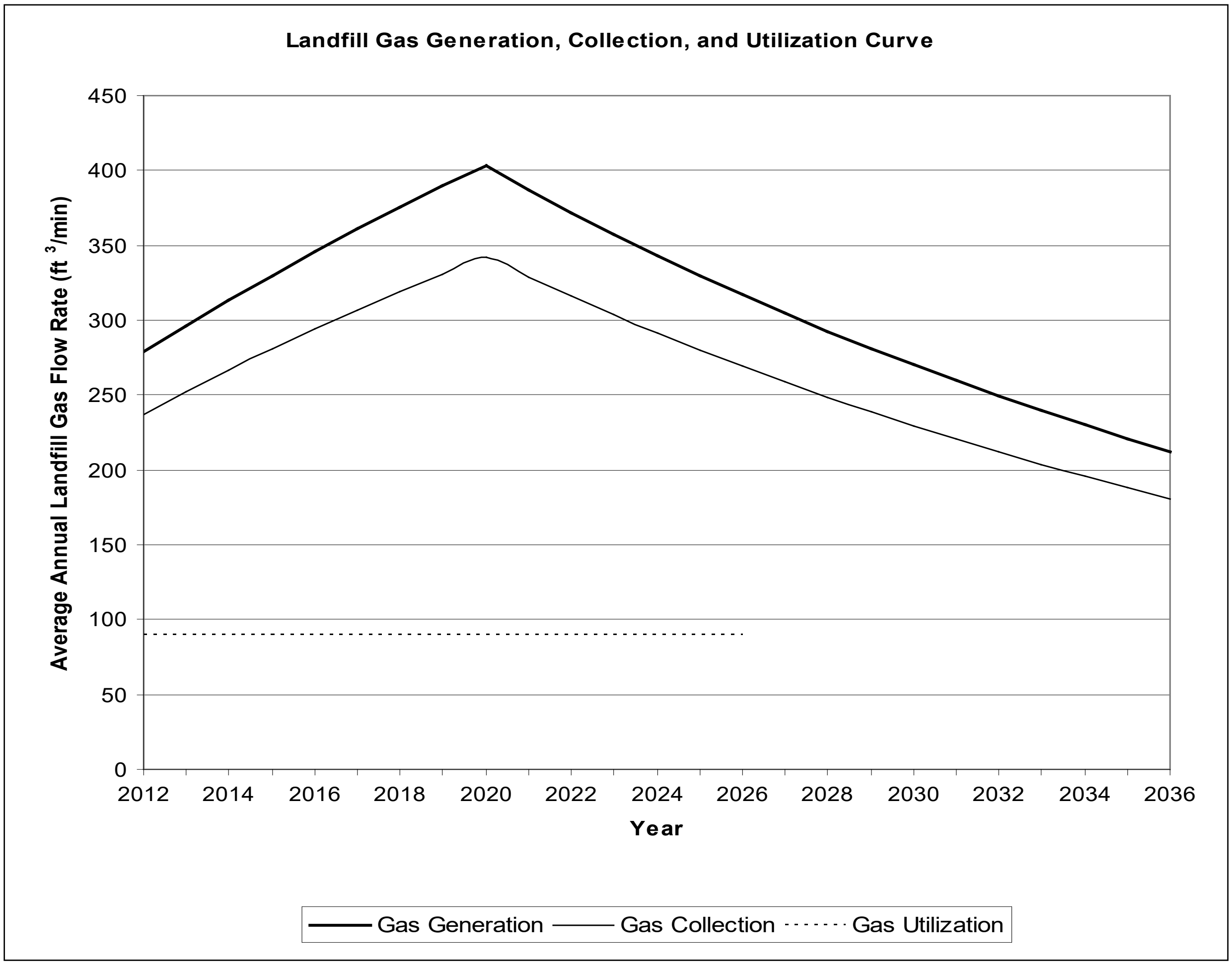

Figure C-1B. Example of an LFG generation, collection and utilization curve for project component B

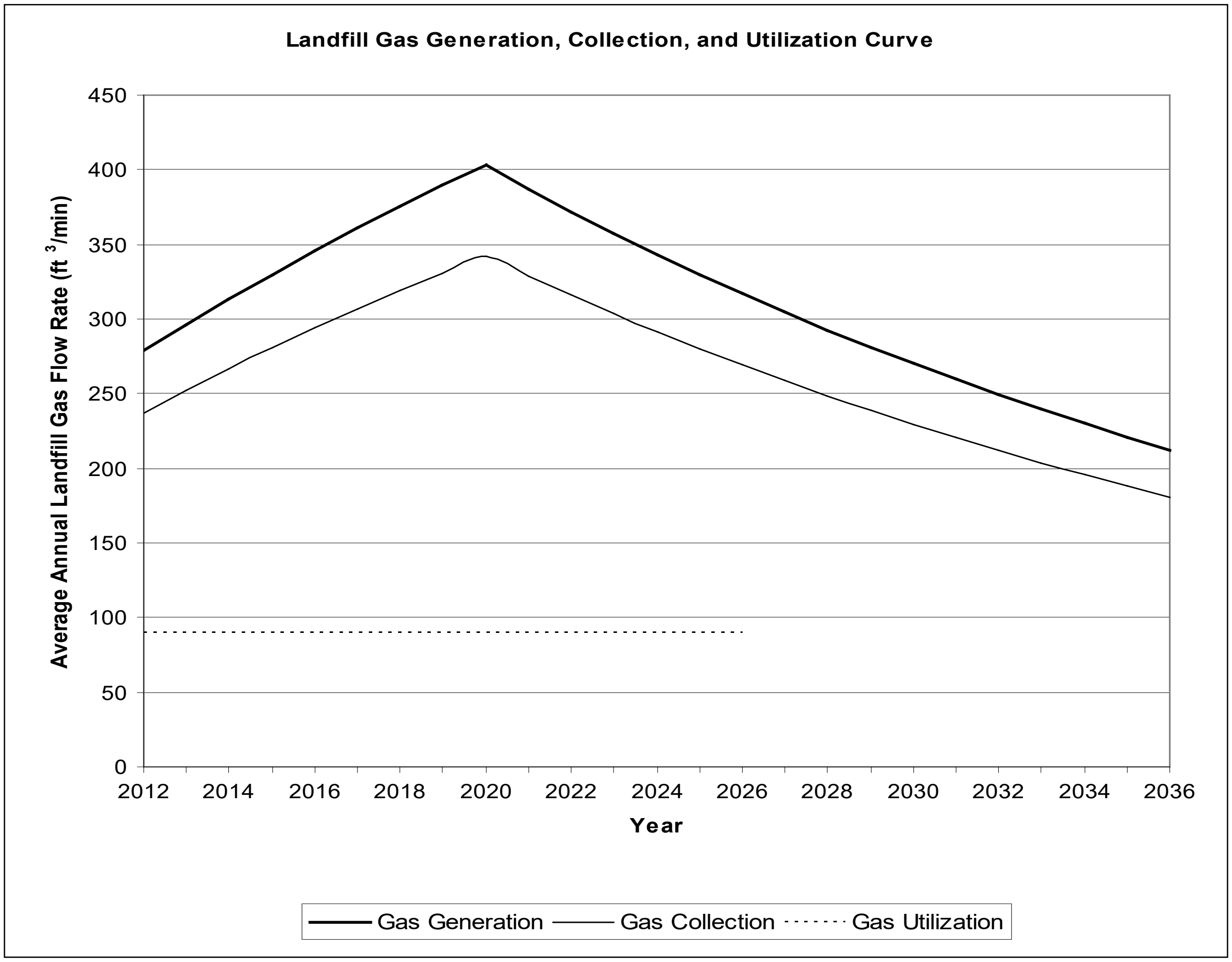

Figure C-1C. Example of an LFG generation, collection and utilization curve for project component C

Appendix D:
Evaluating Local Government-Owned Projects

Appendix D: Evaluating Local Government-Owned Projects

Projects owned by local governments and other public entities should be evaluated under a different set of economic assumptions than the default values recommended in the LFGcost-Web model. These entities are normally exempt from taxes, are subject to lower discount rates and use different approaches than private corporations to finance projects. They may finance smaller projects directly from budgeted funds and choose to fund larger projects through the use of low-interest public bonds. Table D-1 presents default assumptions for use with two types of local government-owned projects.

Table D-1. Recommended Default Assumptions for Local Government-Owned Projects

Parameter	Budget Financed	Bond Financed
Loan lifetime (yrs)	0	10-15 [varies by project lifetime]
Interest rate (%)	0	4
Marginal tax rate (%)	0	0
Discount rate (%)	0	0
Down payment (%)	100	0

Appendix E:

Evaluating Boiler Retrofit Projects

Appendix E: Evaluating Boiler Retrofit Projects

For boiler retrofit projects, there is a required input for users to indicate whether the boiler retrofit costs will be standalone (i.e., evaluated from the perspective of the end user) or combined with direct-use project costs (i.e., evaluated from the perspective of a developer that is responsible for all costs). The outputs of the economic analysis will vary depending on which perspective is used to evaluate the boiler retrofit costs. Specifically, IRR, NPV and Years to breakeven will vary based on the appropriate prices (in $/million Btu) entered for the LFG product price and royalty payment in the ***Optional User Inputs*** table. The following discussion addresses how to set up boiler retrofit scenarios in LFGcost-Web and how to interpret the results produced by LFGcost-Web.

<u>*Boiler retrofit costs kept separate from direct-use project costs*</u> – For evaluating the cost of only the boiler retrofit from the perspective of the end user, the following optional inputs are used:

- *Initial year product price: Landfill gas production* ($/million Btu) should be set to the price that the end user is currently paying for natural gas.
- *Royalty payment for landfill gas utilization* ($/million Btu) should be set to the price that the end user will pay the pipeline owner for delivery of LFG to the end user's property boundary.
- Economic parameters such as *Loan lifetime*, *Interest rate*, *Discount rate*, *Marginal tax rate* and *Down payment* should be the parameters used by the end user.

The difference between the royalty payment and the LFG production price is the revenue used to justify the cost of the boiler retrofit. All economic outputs for this scenario such as IRR, NPV and Years to breakeven are for the end user paying for the boiler retrofit, not the developer of the overall project.

<u>*Boiler retrofit costs combined with direct-use project costs*</u> – For evaluating projects from the perspective of a developer that will pay for LFG treatment (skid-mounted filter, compressor and dehydration unit), pipeline delivery from the landfill to the end user's boiler and conversion of the boiler, the following optional inputs are used:

- *Initial year product price: Landfill gas production* ($/million Btu) should be set to the price that the developer will sell LFG to the end user.
- *Royalty payment for landfill gas utilization* ($/million Btu) should be set to the price that the developer will pay the landfill owner for raw LFG.
- Economic parameters such as *Loan lifetime*, *Interest rate*, *Discount rate*, *Marginal tax rate* and *Down payment* should be the parameters applying to the developer.

The difference between the royalty payment and the LFG production price is the revenue used to justify the cost of LFG treatment, the pipeline and the boiler retrofit. All economic outputs for this scenario such as IRR, NPV and Years to breakeven are for the developer paying for the overall project.

Appendix F: Economic Multipliers for Economic Benefits and Job Creation Analysis

Appendix F: Economic Multipliers for Economic Benefits and Job Creation Analysis

Series: 2012 U.S. Benchmark I-O data and 2018 Regional Data (Type II Multipliers: Direct + Indirect + Induced)									
	Households (64)			**Wholesale Trade (420000)**			**Air and Gas Compressor Manufacturing (333912)**		
State	All-industry (total) final-demand multiplier for output	All-industry (total) final-demand multiplier for earnings	All-industry (total) final-demand multiplier for employment	All-industry (total) final-demand multiplier for output	All-industry (total) final-demand multiplier for earnings	All-industry (total) final-demand multiplier for employment	All-industry (total) final-demand multiplier for output	All-industry (total) final-demand multiplier for earnings	All-industry (total) final-demand multiplier for employment
Alabama	1.0409	0.3157	8.9042	1.7568	0.4883	9.8722	1.9436	0.3954	7.6834
Alaska	0.8572	0.2665	6.5900	1.5486	0.4284	7.7734	1.0000	0.0000	0.0000
Arizona	1.2432	0.3832	9.8718	1.9225	0.5496	10.1478	1.7116	0.3601	7.4098
Arkansas	0.9218	0.2799	7.7051	1.6933	0.4681	9.0135	1.7806	0.3443	6.7102
California	1.2342	0.3699	8.2003	1.9905	0.5710	9.2707	1.7796	0.3768	6.2246
Colorado	1.3081	0.4009	9.9043	2.0182	0.5839	10.1908	1.7903	0.3841	6.7327
Connecticut	0.9938	0.2996	7.0958	1.7953	0.4778	7.7756	1.8030	0.3525	6.1649
Delaware	0.9185	0.2385	6.1760	1.6039	0.3320	5.9032	1.0000	0.0000	0.0000
Florida	1.2362	0.3857	10.5368	1.9377	0.5594	10.8660	1.6656	0.3512	6.7440
Georgia	1.3495	0.4054	11.0939	2.1010	0.5977	11.4686	1.8865	0.3963	7.3791
Hawaii	1.0662	0.3207	7.9723	1.7053	0.4787	8.9621	1.0000	0.0000	0.0000
Idaho	0.9425	0.2909	8.4187	1.6446	0.4558	9.2157	1.0000	0.0000	0.0000
Illinois	1.4293	0.4170	9.2373	2.1296	0.5891	9.7449	2.2433	0.4683	7.6078
Indiana	1.1713	0.3420	8.6220	1.8453	0.5028	9.3066	2.0954	0.4226	7.7771
Iowa	0.9031	0.2726	7.6044	1.6507	0.4453	8.5765	1.7939	0.3446	7.0947
Kansas	1.0765	0.2984	7.9123	1.8065	0.4459	8.3287	1.7855	0.3364	6.4262
Kentucky	1.0804	0.3040	8.1473	1.7733	0.4507	8.9235	1.9012	0.3573	7.3648
Louisiana	1.0240	0.3200	8.6396	1.7306	0.4847	9.2536	1.6960	0.3416	5.9953
Maine	1.0076	0.3245	9.0088	1.7344	0.4974	9.9651	1.0000	0.0000	0.0000
Maryland	1.1242	0.3211	7.5056	1.8211	0.4684	7.8540	1.5273	0.2775	4.6241
Massachusetts	1.0965	0.3238	7.2260	1.8439	0.4895	7.7634	1.6652	0.3202	4.9496
Michigan	1.1334	0.3500	9.0461	1.8945	0.5421	9.6810	2.0889	0.4449	8.0289
Minnesota	1.1675	0.3506	8.4671	1.9001	0.5298	8.8870	1.9587	0.4063	7.1413
Mississippi	0.9596	0.2877	8.0630	1.6564	0.4442	8.8865	1.7095	0.3237	6.8158
Missouri	1.1928	0.3354	9.1211	1.8930	0.4879	9.1661	1.8901	0.3651	6.7169
Montana	0.8893	0.2834	8.2499	1.5733	0.4407	8.8379	1.0000	0.0000	0.0000
Nebraska	0.9548	0.2908	7.9623	1.7394	0.4740	8.7019	1.6260	0.3216	6.5805
Nevada	0.9735	0.2990	8.1323	1.7607	0.4910	9.3295	1.5583	0.3108	6.2030
New Hampshire	1.0085	0.2972	7.0828	1.7516	0.4585	7.5761	1.7534	0.3284	5.6112
New Jersey	1.2586	0.3543	8.0220	1.9791	0.5032	8.2745	1.7441	0.3313	5.2392
New Mexico	0.9197	0.2815	8.1819	1.5711	0.4270	8.5041	1.4210	0.2726	5.8256
New York	1.0381	0.2899	6.5213	1.7861	0.4519	7.0995	1.6216	0.3039	4.7041
North Carolina	1.2266	0.3707	9.7171	1.9561	0.5467	10.2745	1.9961	0.4172	7.4621
North Dakota	0.8548	0.2484	6.3518	1.5529	0.3903	6.7365	1.0000	0.0000	0.0000
Ohio	1.2715	0.3769	9.9593	1.9707	0.5461	10.2836	2.1823	0.4548	8.0868
Oklahoma	1.0624	0.3275	9.0501	1.7766	0.5023	10.1297	1.7957	0.3706	6.9026
Oregon	1.0544	0.3154	8.1324	1.8011	0.4854	8.9032	1.7678	0.3532	6.9663
Pennsylvania	1.2689	0.3733	8.8957	1.9668	0.5341	9.1748	2.1223	0.4365	7.3442
Rhode Island	1.0029	0.2763	7.4161	1.6899	0.4062	7.1450	1.0000	0.0000	0.0000
South Carolina	1.1821	0.3528	10.0496	1.8686	0.5104	10.4929	1.9265	0.3882	8.0490
South Dakota	0.8481	0.2671	7.2636	1.5801	0.4293	8.2126	1.5589	0.3029	5.8881
Tennessee	1.3609	0.3972	9.4752	2.0258	0.5457	10.0081	2.1043	0.4318	8.5847
Texas	1.5319	0.4603	11.1011	2.1694	0.6203	11.1750	2.1134	0.4605	7.9855
Utah	1.2611	0.3753	10.1313	1.9799	0.5611	10.7103	1.8676	0.3959	8.3433
Vermont	0.8894	0.2710	7.6326	1.5598	0.4059	7.9698	1.0000	0.0000	0.0000
Virginia	1.1182	0.3236	8.3666	1.8869	0.5115	8.9174	1.6798	0.3265	6.4469
Washington	1.0677	0.3102	7.1901	1.7714	0.4867	7.9858	1.5855	0.3179	6.0562
West Virginia	0.8065	0.2372	6.6998	1.5399	0.3998	7.7047	1.0000	0.0000	0.0000
Wisconsin	1.0746	0.3322	8.5624	1.8025	0.5015	9.3589	1.9500	0.4032	7.4298
Wyoming	0.7375	0.2270	6.5296	1.4732	0.3996	7.6806	1.0000	0.0000	0.0000

Estimates are based on BEA 2018 RIMS II multipliers that are most representative of the materials used in an LFG energy project. BEA does not endorse any resulting estimates and/or conclusions about the economic impact of a proposed change on an area.

Appendix F: Economic Multipliers for Economic Benefits and Job Creation Analysis

Series: 2012 U.S.	Benchmark I-O data and 2018 Regional Data (Type II Multipliers: Direct + Indirect + Induced)								
	Plastics Pipe, Pipe Fitting, and Unlaminated Profile Shape Manufacturing (326120)			Other Nonmetallic Mineral Mining and Quarrying (2123A0)			Electrical Equipment and Appliance Manufacturing (14)		
State	All-industry (total) final-demand multiplier for output	All-industry (total) final-demand multiplier for earnings	All-industry (total) final-demand multiplier for employment	All-industry (total) final-demand multiplier for output	All-industry (total) final-demand multiplier for earnings	All-industry (total) final-demand multiplier for employment	All-industry (total) final-demand multiplier for output	All-industry (total) final-demand multiplier for earnings	All-industry (total) final-demand multiplier for employment
Alabama	2.2995	0.4712	9.5800	1.8239	0.4103	8.9172	1.9953	0.4204	8.4694
Alaska	1.0000	0.0000	0.0000	1.6015	0.3464	8.5711	1.3154	0.2892	6.6807
Arizona	1.5684	0.3441	7.0304	1.7499	0.4059	7.5157	1.8047	0.4438	8.3220
Arkansas	1.9883	0.3944	7.8754	1.7534	0.3799	9.3819	1.8127	0.3853	7.7631
California	1.6625	0.3624	6.5873	1.8399	0.4295	8.0440	1.8176	0.4360	7.2350
Colorado	1.6207	0.3601	7.0035	1.9354	0.4635	11.0326	1.7784	0.4330	8.7169
Connecticut	1.7237	0.3400	6.1423	1.6993	0.3794	7.7307	1.8549	0.4014	6.7422
Delaware	1.9017	0.2687	4.5349	1.6403	0.3293	7.2345	1.3766	0.2292	3.9548
Florida	1.5816	0.3460	7.0556	1.7655	0.4159	9.4845	1.7027	0.4121	8.7531
Georgia	1.9805	0.4240	8.8790	1.9237	0.4527	8.3125	1.9448	0.4477	8.6996
Hawaii	1.0000	0.0000	0.0000	1.6562	0.3753	6.5580	1.4313	0.3379	7.7832
Idaho	1.4780	0.3044	7.1083	1.5981	0.3434	8.2464	1.5550	0.3671	7.9784
Illinois	2.4343	0.5082	8.6721	2.0848	0.4753	7.6663	2.1840	0.5070	8.4213
Indiana	2.2736	0.4617	8.9355	1.8782	0.4044	7.9807	2.0503	0.4780	9.2194
Iowa	1.9478	0.3823	7.8130	1.6611	0.3561	7.3846	1.7151	0.3467	7.1201
Kansas	1.7272	0.3374	7.4290	1.8737	0.3946	8.6521	1.6559	0.3453	6.3578
Kentucky	2.2005	0.4138	8.7269	1.8428	0.3849	8.6950	1.9644	0.3756	7.0353
Louisiana	2.3470	0.4865	9.6138	1.8480	0.4087	10.1104	1.7029	0.4115	7.8646
Maine	1.5505	0.3346	7.6915	1.6254	0.3785	8.5763	1.6375	0.4069	8.2484
Maryland	1.4863	0.2894	5.0703	1.6466	0.3229	5.9737	1.5328	0.3151	5.6642
Massachusetts	1.9087	0.3772	6.4015	1.7087	0.3765	7.5338	1.8373	0.4086	6.6149
Michigan	2.1583	0.4618	8.8931	1.8548	0.4328	9.0523	2.0099	0.4472	8.1651
Minnesota	1.9230	0.4031	7.1219	1.8830	0.4256	7.9738	1.8571	0.4412	7.8083
Mississippi	2.0347	0.3963	7.8684	1.7378	0.3696	9.5439	1.8032	0.4039	8.4334
Missouri	1.9106	0.3717	7.2591	1.8167	0.3838	9.6242	1.8199	0.3912	7.6669
Montana	1.3914	0.2938	6.8697	1.6655	0.3599	7.5737	1.4588	0.3313	7.3830
Nebraska	1.7557	0.3514	7.1170	1.7050	0.3768	8.8908	1.6767	0.3827	7.2426
Nevada	1.4567	0.3078	6.4881	1.6327	0.3700	7.1511	1.6699	0.3332	6.3367
New Hampshire	1.5654	0.2997	5.5495	1.6721	0.3725	9.2087	1.9360	0.3851	6.6999
New Jersey	1.9482	0.3726	6.2602	1.8694	0.4086	6.5405	1.8995	0.4141	6.9877
New Mexico	1.3866	0.2762	6.4449	1.6435	0.3516	7.0358	1.5312	0.3439	7.4671
New York	1.5804	0.2944	4.8760	1.6575	0.3506	6.6808	1.6780	0.3807	6.5910
North Carolina	2.1323	0.4493	8.8797	1.8219	0.4172	8.9397	2.0068	0.4521	8.5670
North Dakota	1.4264	0.2609	4.9023	1.6632	0.3064	5.7383	1.5054	0.2886	6.1722
Ohio	2.3873	0.4979	9.5995	1.9821	0.4426	7.8510	2.1453	0.4912	9.4659
Oklahoma	1.6147	0.3441	7.2678	1.8375	0.4180	7.6135	1.6668	0.3678	7.8679
Oregon	1.6394	0.3352	6.9339	1.7306	0.3846	9.5800	1.7588	0.4083	7.5839
Pennsylvania	2.2584	0.4642	8.3517	2.0049	0.4417	10.1658	2.1015	0.4945	8.7856
Rhode Island	1.8740	0.3265	5.9947	1.6455	0.3484	9.0425	1.7133	0.3251	6.0473
South Carolina	2.3320	0.4703	8.9613	1.8113	0.3986	8.9971	2.0611	0.4490	8.9506
South Dakota	1.4692	0.2877	6.2618	1.5751	0.3321	6.8036	1.5407	0.4096	8.4676
Tennessee	2.3154	0.4728	9.2424	1.9447	0.4298	7.9067	2.0696	0.4478	8.6474
Texas	2.6770	0.5854	10.2614	2.1793	0.5134	10.9689	2.1806	0.5202	9.4060
Utah	1.6257	0.3543	7.6226	1.9259	0.4463	11.3184	1.8487	0.4011	7.7847
Vermont	1.4841	0.2926	5.9933	1.5061	0.3042	7.6566	1.6067	0.3362	6.8207
Virginia	1.6830	0.3404	6.9750	1.7164	0.3623	7.9294	1.6582	0.3834	7.3405
Washington	1.6783	0.3489	6.7121	1.7247	0.3878	6.2345	1.7034	0.4381	7.5778
West Virginia	2.0920	0.3661	7.5404	1.6746	0.3335	6.1644	1.6795	0.3161	6.1117
Wisconsin	1.8154	0.3829	7.6468	1.7709	0.3974	7.8926	1.9006	0.4722	8.5651
Wyoming	1.3543	0.2733	6.2888	1.5876	0.3289	5.6766	1.4095	0.2862	5.6108

Estimates are based on BEA 2018 RIMS II multipliers that are most representative of the materials used in an LFG energy project. BEA does not endorse any resulting estimates and/or conclusions about the economic impact of a proposed change on an area.

Appendix F: Economic Multipliers for Economic Benefits and Job Creation Analysis

Series: 2012 U.S.	Benchmark I-O data and 2018 Regional Data (Type II Multipliers: Direct + Indirect + Induced)								
	Electric Power Generation, Trans, and Dist (2211AO)			**Other Motor Vehicle Parts Manufacturing (336390)**			**Professional, Scientific, and Technical Services (50)**		
State	All-industry (total) final-demand multiplier for output	All-industry (total) final-demand multiplier for earnings	All-industry (total) final-demand multiplier for employment	All-industry (total) final-demand multiplier for output	All-industry (total) final-demand multiplier for earnings	All-industry (total) final-demand multiplier for employment	All-industry (total) final-demand multiplier for output	All-industry (total) final-demand multiplier for earnings	All-industry (total) final-demand multiplier for employment
Alabama	1.6657	0.3436	5.8224	2.3318	0.4858	10.5750	1.9002	0.7629	14.8638
Alaska	1.6191	0.3276	4.7535	1.3337	0.2507	5.5445	1.6705	0.6763	12.4428
Arizona	1.6417	0.3487	5.6323	1.7950	0.3881	8.2785	2.0979	0.8351	16.7709
Arkansas	1.5486	0.3076	5.1064	2.0204	0.3981	8.8467	1.7519	0.7094	14.8482
California	1.6572	0.3517	4.9582	1.8535	0.4019	7.7908	2.1586	0.8403	13.3391
Colorado	1.8111	0.3959	6.2682	1.8554	0.4076	7.8574	2.1835	0.8608	15.2177
Connecticut	1.4578	0.2790	3.7972	1.8986	0.3788	6.7507	1.8730	0.7139	11.4664
Delaware	1.4596	0.2349	3.3176	1.0000	0.0000	0.0000	1.6713	0.5271	8.7628
Florida	1.5753	0.3331	5.5337	1.7362	0.3746	8.0060	2.1140	0.8521	17.3360
Georgia	1.6252	0.3406	5.8531	2.2195	0.4759	9.9349	2.2330	0.8672	16.7798
Hawaii	1.5230	0.3092	4.6966	1.0000	0.0000	0.0000	1.8866	0.7555	14.7182
Idaho	1.4762	0.2950	5.0674	1.6106	0.3270	7.6713	1.7735	0.6983	14.7779
Illinois	1.7791	0.3656	5.3478	2.6157	0.5565	10.1614	2.2712	0.8498	13.8495
Indiana	1.6535	0.3285	5.3071	2.4504	0.5031	9.9803	1.9716	0.7748	14.8296
Iowa	1.4167	0.2578	4.1710	2.0826	0.4071	8.2973	1.7293	0.6994	14.2558
Kansas	1.6410	0.3167	5.1385	1.8118	0.3484	7.2935	1.8730	0.6632	12.9295
Kentucky	1.6826	0.3255	5.5193	2.3325	0.4484	9.2897	1.8700	0.7123	14.7675
Louisiana	1.7522	0.3691	5.9742	1.7972	0.3728	8.2420	1.8784	0.7681	14.8388
Maine	1.4669	0.2977	5.0015	1.6057	0.3357	7.1684	1.8263	0.7587	15.6555
Maryland	1.4891	0.2768	3.9250	1.5816	0.2956	5.7218	1.9519	0.7098	11.5502
Massachusetts	1.4722	0.2808	3.8149	1.7728	0.3502	6.1748	2.0042	0.7389	11.2715
Michigan	1.5476	0.3211	5.0530	2.4423	0.5300	10.1369	2.0232	0.7906	14.3937
Minnesota	1.6054	0.3241	4.9132	2.0122	0.4270	8.0299	2.0262	0.7835	13.4214
Mississippi	1.6230	0.3248	5.5758	2.0365	0.3927	8.3765	1.7614	0.7097	15.0329
Missouri	1.6103	0.3045	5.0725	2.0762	0.4095	8.6553	1.9360	0.6682	12.3599
Montana	1.6446	0.3369	5.4781	1.4707	0.2960	6.9507	1.7211	0.7328	16.0008
Nebraska	1.4789	0.2873	4.3514	1.8938	0.3817	7.4074	1.8131	0.7194	14.0218
Nevada	1.4456	0.2878	4.5730	1.5901	0.3224	6.3470	1.8472	0.7470	15.0784
New Hampshire	1.4257	0.2626	3.7749	1.0000	0.0000	0.0000	1.8632	0.7156	12.1657
New Jersey	1.6160	0.3102	4.3986	1.9045	0.3719	6.6128	2.1121	0.7512	12.1274
New Mexico	1.6691	0.3395	5.6819	1.4352	0.2813	6.6192	1.7336	0.6560	12.5681
New York	1.4671	0.2702	3.5970	1.6790	0.3211	5.5905	1.8816	0.6504	10.1217
North Carolina	1.5537	0.3141	5.1655	2.1166	0.4493	8.9430	2.1056	0.8183	15.4965
North Dakota	1.6538	0.3116	4.6309	1.5195	0.2743	5.8385	1.6534	0.6395	12.0478
Ohio	1.6975	0.3455	5.6837	2.5564	0.5413	10.7439	2.0845	0.8041	15.5084
Oklahoma	1.7557	0.3778	6.5124	1.7987	0.3799	8.0474	1.9026	0.7850	16.5929
Oregon	1.5237	0.2968	4.5727	1.9116	0.3914	7.8995	1.9113	0.7431	14.4397
Pennsylvania	1.8089	0.3709	5.5617	2.2870	0.4805	8.8449	2.0819	0.7721	12.9366
Rhode Island	1.4076	0.2476	3.8613	1.0000	0.0000	0.0000	1.7757	0.6331	12.1307
South Carolina	1.5748	0.3115	5.6166	2.3674	0.4886	10.1598	2.0294	0.7831	16.3280
South Dakota	1.4260	0.2770	4.3031	1.6268	0.3215	6.9998	1.6697	0.6919	14.4778
Tennessee	1.6542	0.3317	5.5038	2.4614	0.5125	10.3581	2.1672	0.8286	15.6426
Texas	1.9987	0.4447	7.0030	2.2312	0.4957	9.6563	2.3815	0.9202	16.2254
Utah	1.7838	0.3804	6.4783	2.0241	0.4382	8.9192	2.1222	0.8205	17.0328
Vermont	1.3758	0.2315	3.6657	1.0000	0.0000	0.0000	1.7215	0.7149	14.5322
Virginia	1.6153	0.3178	4.8100	1.7470	0.3454	6.5239	1.9572	0.7179	12.0488
Washington	1.5676	0.3130	4.6167	1.6812	0.3452	6.7089	1.9289	0.7564	12.3300
West Virginia	1.6287	0.3037	4.9642	1.8486	0.3166	6.9777	1.6385	0.6508	12.1810
Wisconsin	1.5174	0.3063	4.7698	2.1103	0.4449	8.8805	1.9132	0.7691	14.7537
Wyoming	1.5807	0.3098	4.8452	1.4168	0.2677	6.1337	1.5706	0.6644	13.6895

Estimates are based on BEA 2018 RIMS II multipliers that are most representative of the materials used in an LFG energy project. BEA does not endorse any resulting estimates and/or conclusions about the economic impact of a proposed change on an area.

Series: 2012 U.S.	Benchmark I-O data and 2018 Regional Data (Type II Multipliers: Direct + Indirect + Induced)					
	Natural Gas Distribution (221200)			Insurance Carriers, Except Direct Life Insurance (5241XX)		
State	All-industry (total) final-demand multiplier for output	All-industry (total) final-demand multiplier for earnings	All-industry (total) final-demand multiplier for employment	All-industry (total) final-demand multiplier for output	All-industry (total) final-demand multiplier for earnings	All-industry (total) final-demand multiplier for employment
Alabama	1.5301	0.3249	5.8971	1.9864	0.4981	9.6090
Alaska	1.6488	0.3556	4.7867	1.4331	0.3560	6.3645
Arizona	1.5308	0.3257	5.7652	2.1346	0.5445	10.5956
Arkansas	1.4957	0.3072	5.4129	1.5849	0.3910	7.8937
California	1.6129	0.3491	4.8817	1.9999	0.5124	8.1763
Colorado	1.9160	0.4458	6.5724	2.0124	0.5205	9.4770
Connecticut	1.4240	0.2764	3.9934	1.9962	0.4457	6.9579
Delaware	1.3516	0.2165	3.1878	1.6673	0.3055	5.0932
Florida	1.5068	0.3184	5.5599	2.1774	0.5612	11.0686
Georgia	1.5757	0.3343	5.6382	2.2122	0.5576	10.9856
Hawaii	1.4029	0.2820	4.6163	1.6561	0.4148	7.9162
Idaho	1.3776	0.2730	4.6973	1.6168	0.3992	8.3480
Illinois	1.6214	0.3387	5.2491	2.2774	0.5720	8.9745
Indiana	1.4692	0.2950	4.9867	1.9163	0.4716	8.7002
Iowa	1.3713	0.2548	4.1355	1.9207	0.4692	8.8576
Kansas	1.6827	0.3419	6.0106	1.9622	0.4320	8.0232
Kentucky	1.5197	0.3019	5.1898	1.9569	0.4428	7.8573
Louisiana	1.7722	0.3926	6.2786	1.9822	0.5006	9.5471
Maine	1.4038	0.2874	5.0531	1.9471	0.4915	9.1760
Maryland	1.4365	0.2695	4.0430	1.9445	0.4488	7.2016
Massachusetts	1.4593	0.2831	3.8049	1.9745	0.4802	7.3269
Michigan	1.5312	0.3270	5.2469	1.8029	0.4586	8.4338
Minnesota	1.5192	0.3133	4.9407	2.0976	0.5245	8.5168
Mississippi	1.5470	0.3221	5.8547	1.6856	0.4160	8.4946
Missouri	1.4880	0.2816	4.6199	2.0630	0.4697	8.6808
Montana	1.6779	0.3670	6.1522	1.9044	0.4801	10.1192
Nebraska	1.4117	0.2759	4.0517	1.9510	0.4700	8.8004
Nevada	1.3752	0.2717	4.3429	1.7734	0.4422	8.4830
New Hampshire	1.3905	0.2576	3.9844	1.9748	0.4283	6.9901
New Jersey	1.5358	0.2974	4.2411	2.1437	0.4815	7.5461
New Mexico	1.6644	0.3578	6.2566	1.5087	0.3765	7.7686
New York	1.4264	0.2626	3.5139	1.9284	0.3930	5.9068
North Carolina	1.4918	0.3019	5.2774	1.9925	0.4948	9.3408
North Dakota	1.6508	0.3268	4.7032	1.8299	0.4160	8.2167
Ohio	1.5900	0.3335	5.5014	2.0664	0.5089	9.3469
Oklahoma	1.7942	0.4062	6.6267	1.7759	0.4513	9.3784
Oregon	1.4181	0.2735	4.2101	1.9006	0.4611	8.0646
Pennsylvania	1.7699	0.3805	5.8278	2.1308	0.5150	8.6724
Rhode Island	1.3837	0.2441	4.1857	1.9384	0.3729	6.5248
South Carolina	1.4493	0.2820	5.2262	1.9026	0.4661	9.8078
South Dakota	1.3657	0.2706	4.2981	1.8612	0.4542	9.2629
Tennessee	1.5512	0.3138	5.4257	2.1667	0.5312	9.6469
Texas	2.0478	0.4785	7.2576	2.3100	0.5948	10.8734
Utah	1.7189	0.3778	6.4542	2.1432	0.5435	11.2429
Vermont	1.3113	0.2207	3.7189	1.6472	0.4019	7.5466
Virginia	1.4741	0.2915	4.2507	1.8908	0.4493	8.2009
Washington	1.4304	0.2860	4.4322	1.7236	0.4255	7.2128
West Virginia	1.6271	0.3224	5.8773	1.5460	0.3597	7.2113
Wisconsin	1.4256	0.2876	4.5238	2.0148	0.5070	9.4065
Wyoming	1.5959	0.3332	5.6464	1.4172	0.3412	6.8311

Estimates are based on BEA 2018 RIMS II multipliers that are most representative of the materials used in an LFG energy project. BEA does not endorse any resulting estimates and/or conclusions about the economic impact of a proposed change on an area.

Appendix G: Ranking Analysis for Economic Multipliers

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Output Ranking Table											
State	Households (64)	Wholesale Trade (420000)	Other Nonmetallic Mineral Mining and Quarrying (2123A0)	Electrical Equipment and Appliance Manufacturing (14)	Electric Power Generation, Trans, and Dist (2211AO)	Natural Gas Distribution (221200)	Insurance Carriers, Except Direct Life Insurance (5241XX)	Average	Std Dev	Range	Overall Rank
Texas	1	1	1	2	1	1	1	1	0	1	1
Illinois	2	2	2	1	5	13	2	4	4	12	2
Pennsylvania	7	10	3	4	3	5	9	6	3	7	3
Tennessee	3	4	5	5	13	18	5	8	6	15	4
Ohio	6	9	4	3	8	16	11	8	4	13	5
Utah	8	7	7	18	4	6	7	8	5	14	5
Colorado	5	5	6	25	2	2	14	8	8	23	7
Georgia	4	3	8	12	20	17	3	10	7	17	8
New Jersey	9	8	12	15	23	20	6	13	6	17	9
California	12	6	16	21	12	14	15	14	5	15	10
Minnesota	17	14	9	16	26	25	10	17	7	17	11
Arizona	10	13	25	23	17	22	8	17	7	17	12
Indiana	16	19	10	7	15	31	30	18	9	24	13
North Carolina	13	11	19	9	31	28	17	18	8	22	13
Kentucky	22	28	15	11	9	24	23	19	7	19	15
Florida	11	12	23	31	28	26	4	19	10	27	16
Missouri	14	16	20	20	25	29	12	19	6	17	17
Alabama	29	31	18	10	11	23	18	20	8	21	18
Louisiana	31	35	14	30	7	4	19	20	12	31	18
Kansas	23	22	11	38	18	7	22	20	10	31	20
Michigan	18	15	13	8	33	21	37	21	11	29	21
South Carolina	15	18	21	6	29	33	32	22	10	27	22
Oklahoma	27	27	17	36	6	3	38	22	14	35	22
Wisconsin	24	23	22	14	36	37	13	24	9	24	24
Massachusetts	21	20	30	19	40	32	21	26	8	21	25
Virginia	20	17	29	37	24	30	34	27	7	20	26
Connecticut	35	25	32	17	44	38	16	30	11	28	27
Mississippi	37	39	26	24	21	19	41	30	9	22	27
Oregon	28	24	27	26	34	39	33	30	5	15	29
Washington	25	29	28	29	30	35	40	31	5	15	30
Maryland	19	21	40	43	37	34	26	31	9	24	31
New Hampshire	32	32	34	13	47	43	20	32	12	34	32
Montana	45	44	35	46	16	8	31	32	15	38	33
Arkansas	40	37	24	22	32	27	46	33	9	24	34
New York	30	26	38	33	41	36	28	33	5	15	35
North Dakota	47	47	36	45	14	10	36	34	16	37	36
Nebraska	38	33	31	34	38	40	24	34	5	16	37
New Mexico	41	45	42	44	10	9	48	34	17	39	38
West Virginia	49	49	33	32	19	12	47	34	15	37	39
Maine	33	34	45	39	42	41	25	37	7	20	40
Rhode Island	34	38	41	28	49	44	27	37	8	22	41
Hawaii	26	36	39	47	35	42	43	38	7	21	42
Iowa	43	40	37	27	48	47	29	39	8	21	43
Alaska	46	48	46	50	22	11	49	39	16	39	44
Nevada	36	30	44	35	45	46	39	39	6	16	45
Wyoming	50	50	48	48	27	15	50	41	14	35	46

Estimates are based on BEA 2018 RIMS II multipliers that are most representative of the materials used in an LFG energy project. BEA does not endorse any resulting estimates and/or conclusions about the economic impact of a proposed change on an area.

Output Ranking Table											
State	Households (64)	Wholesale Trade (420000)	Other Nonmetallic Mineral Mining and Quarrying (2123A0)	Electrical Equipment and Appliance Manufacturing (14)	Electric Power Generation, Trans, and Dist (2211AO)	Natural Gas Distribution (221200)	Insurance Carriers, Except Direct Life Insurance (5241XX)	Average	Std Dev	Range	Overall Rank
Idaho	39	41	47	41	39	45	45	42	3	8	47
Delaware	42	42	43	49	43	49	42	44	3	7	48
South Dakota	48	43	49	42	46	48	35	44	5	14	49
Vermont	44	46	50	40	50	50	44	46	4	10	50

High	**Arizona**
Median	**Wisconsin**
Low	**West Virginia**

Notes on Ranking Analysis:

Analysis included only the seven sets of multipliers that were assigned to within the state. Multipliers assigned only to the national level were excluded from the analysis.

High Multiplier: 25th percentile. Looked for states with an overall rank between 9 and 15 for both employment and output after averaging the rank of the seven regional multipliers. Arizona output rank = 12, employment rank = 13 (yellow highlight) was selected. North Carolina is the only other state in yellow for this grouping; output rank = 13, employment rank = 11 (however, we used Arizona because the average rank of 12.5 is closer to the 25th percentile (12.5) than the average rank of 12 for North Carolina).

Median Multiplier: 50th percentile. Looked for states with an overall rank between 22 and 29 for both employment and output after averaging the rank of the seven regional multipliers (blue highlight). Wisconsin is the only state in the middle for both output and employment.

Low Multiplier: 75th percentile. Looked for states with an overall rank between 36 and 43 for both employment and output after averaging the rank of the seven regional multipliers (pink highlight). West Virginia output rank = 39, employment rank = 38 (pink highlight) was selected. Rhode Island is the only other state in pink for this grouping; output rank = 41, employment rank = 42 (however, we used West Virginia because the average rank of 38.5 is closer to the 75th percentile (37.5) than the average rank of 41.5 for Rhode Island).

Estimates are based on BEA 2018 RIMS II multipliers that are most representative of the materials used in an LFG energy project. BEA does not endorse any resulting estimates and/or conclusions about the economic impact of a proposed change on an area.

Employment Ranking Table

State	Households (64)	Wholesale Trade (420000)	Other Nonmetallic Mineral Mining and Quarrying (2123A0)	Electrical Equipment and Appliance Manufacturing (14)	Electric Power Generation, Trans, and Dist (2211AO)	Natural Gas Distribution (221200)	Insurance Carriers, Except Direct Life Insurance (5241XX)	Average	Std Dev	Range	Overall Rank
Texas	1	2	3	2	1	1	4	2	1	3	1
Utah	4	4	1	23	3	4	1	6	8	22	2
Colorado	7	8	2	7	4	3	11	6	3	9	3
Florida	3	3	9	6	14	16	2	8	6	14	4
Georgia	2	1	22	8	6	15	3	8	8	21	5
South Carolina	5	5	14	4	11	23	7	10	7	19	6
Ohio	6	6	30	1	8	17	14	12	10	29	7
Alabama	16	13	16	12	7	9	9	12	4	9	7
Louisiana	18	20	5	21	5	5	10	12	7	16	9
Oklahoma	13	10	34	20	2	2	13	13	11	32	10
North Carolina	9	7	15	10	20	20	15	14	5	13	11
Pennsylvania	17	22	4	5	13	12	23	14	8	19	11
Arizona	8	9	37	16	10	13	5	14	11	32	13
Tennessee	10	11	28	9	16	18	8	14	7	20	14
Illinois	11	14	32	15	18	21	18	18	7	21	15
Mississippi	30	30	8	14	12	11	25	19	9	22	16
Indiana	19	18	25	3	19	26	21	19	8	23	17
Maine	15	12	20	17	26	25	17	19	5	14	18
Michigan	14	15	12	18	25	22	27	19	6	15	19
Missouri	12	23	6	26	23	32	22	21	9	26	20
Montana	24	31	35	30	17	7	6	21	12	29	21
Wisconsin	20	16	29	11	32	34	12	22	10	23	22
Idaho	22	21	23	19	24	31	28	24	4	12	23
Arkansas	35	24	10	25	22	19	35	24	9	25	24
Minnesota	21	29	26	22	29	27	24	25	3	8	25
Kentucky	27	26	18	35	15	24	36	26	8	21	26
New Mexico	26	34	41	29	9	6	37	26	14	35	27
California	25	19	24	33	28	28	31	27	5	14	28
Kansas	34	35	19	43	21	8	33	28	12	35	29
Oregon	28	28	7	27	38	40	32	29	11	33	30
Virginia	23	27	27	31	31	38	30	30	5	15	31
Nebraska	33	32	17	32	40	43	20	31	10	26	32
South Dakota	40	37	42	13	41	37	16	32	12	29	33
Hawaii	32	25	44	24	34	33	34	32	7	20	33
Nevada	29	17	40	44	37	36	26	33	9	27	35
Iowa	37	33	38	34	42	42	19	35	8	23	36
Alaska	46	42	21	40	33	29	48	37	10	27	37
West Virginia	45	44	47	46	27	10	42	37	14	37	38
New Jersey	31	36	45	36	39	39	39	38	4	14	39
Washington	42	38	46	28	36	35	41	38	6	18	40
New Hampshire	44	46	11	39	47	46	44	40	13	36	41
Rhode Island	39	47	13	47	44	41	47	40	12	34	42
Vermont	36	39	33	37	48	48	38	40	6	15	43
Wyoming	47	45	50	49	30	14	46	40	13	36	44
North Dakota	49	49	49	45	35	30	29	41	9	20	45
Connecticut	43	41	31	38	46	45	45	41	5	15	46

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Employment Ranking Table											
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Massachusetts	41	43	36	41	45	47	40	42	4	11	47
Maryland	38	40	48	48	43	44	43	43	4	10	48
New York	48	48	43	42	49	49	49	47	3	7	49
Delaware	50	50	39	50	50	50	50	48	4	11	50

High	**Pennsylvania**
Median	**Arkansas**
Low	**New Jersey**

Notes on Ranking Analysis:

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