CLIMATE LEADERS GREENHOUSE GAS INVENTORY PROTOCOL

OFFSET PROJECT METHODOLOGY

for

Project Type: Captured Methane End Use

Climate Protection Partnerships Division/Climate Change Division

Office of Atmospheric Programs

U.S. Environmental Protection Agency

August 2008

Version 1.0

Table of Contents

Climate Leaders *is an EPA industry-government partnership that works with companies to develop comprehensive climate change strategies. Partner companies commit to reducing their impact on the global environment by setting aggressive greenhouse gas reduction goals and annually reporting their progress to EPA.*

Introduction

An important objective of the Climate Leaders program is to focus corporate attention on achieving cost-effective greenhouse gas (GHG) reductions within the boundary of the organization (i.e., internal projects and reductions). Partners may also use reductions and/or removals which occur outside their organizational boundary (i.e., external reductions or "offsets") to help them achieve their goals. To ensure that the GHG emission reductions from offsets are credible, Partners must ensure that the reductions meet four key accounting principles:

- ***Real:*** The quantified GHG reductions must represent actual emission reductions that have already occurred.
- ***Additional:*** The GHG reductions must be surplus to regulation and beyond what would have happened in the absence of the project or in a business-as-usual scenario based on a performance standard methodology.
- ***Permanent:*** The GHG reductions must be permanent or have guarantees to ensure that any losses are replaced in the future.
- ***Verifiable:*** The GHG reductions must result from projects whose performance can be readily and accurately quantified, monitored and verified.

This guidance provides a performance standard (accounting methodology) for greenhouse gas (GHG) offset projects that involve the end use of methane (CH_4) captured from landfill operations or manure management systems to produce heat or electricity.[1] The accounting methodologies presented in this paper address the end use of captured CH_4, providing measurement and monitoring guidance for these activities. Program design issues (e.g., project lifetime, project start date) are not within the scope of this guidance and are addressed in the Climate Leaders offset program overview document: Using Offsets to Help Climate Leaders Achieve Their GHG Reduction Goals.[2]

Description of Project Type

Landfills and manure management systems produce CH_4, which can be collected and combusted to produce heat or electricity. In this paper, the term "end use" refers to

[1] The displacement of grid electricity is not addressed in this protocol.
[2] Please visit http://www.epa.gov/climateleaders/resources/optional-module.html to download the overview document.

the utilization (for heat or energy production) of CH_4 after it is captured. End use systems vary by the nature of the activity that produces methane:

- **Landfills**—An established method for reducing emissions from landfills is the collection and combustion of landfill gas. The use of CH_4 captured from landfill operations is increasing in the United States. The US EPA's Landfill Methane Outreach program (LMOP) database shows that some 435 landfills are converting landfill gas (LFG) to energy in a variety of ways, including combustion for electricity production, injection into natural gas pipelines, use in boilers for heating, and conversion into transportation fuel.[3]
- **Manure Management Systems**—An established method for reducing GHG emissions from manure management systems is the replacement of a conventional anaerobic manure management technology (e.g., lagoons, liquid/slurry systems) with a digester system that collects and combusts manure gas. At some digester systems biogas is combusted for electricity or heat production and use. The EPA's AgStar web site indicates more than 111 active projects are converting manure management gas to energy in the United States.[4]

This section provides information on the general parameters that the proposed end use project associated with the activities described above must match to use this performance standard.

Technology/Practice Introduced. This guidance document addresses the operation of a CH_4 utilization project.[5] In CH_4 end use projects, commonly employed combustion sources include turbines, reciprocating engines, boilers, heaters, furnaces and kilns. In some cases the fuel displaced is obvious or previously known, such as in an equipment retrofit case where there is a record of the type and quantity of fuel being substituted. In most cases, however, the displaced fuel is a mix of the fuels that would have been used to generate electricity or heat.

This paper addresses four distinct project types for end uses of captured CH_4. These are listed and described below.

End Use Project Type 1—Generation of hot water or steam from boilers (onsite and offsite). This project type involves the generation of hot water or steam using industrial or commercial boilers. Captured CH_4 can be used at any type of boiler whether located onsite or offsite.

---

[3] http://www.epa.gov/lmop/docs/map.pdf. Accessed April 14, 2008.
[4] http://www.epa.gov/agstar/accomplish.html. Accessed April 14, 2008.
[5] Reductions that can be achieved through the collection and combustion of CH_4 are quantified using Climate Leaders methodologies specific to the source of the captured gas (i.e. landfills and manure management systems).

End Use Project Type 2—Generation of electricity (Displacing onsite fossil fuel use). Electricity generation using a reciprocating engine, steam turbine, or gas turbine is a common end use of captured gas. In larger applications, high-efficiency Combined Cycle Gas Turbines (CCGT) can be operated successfully. Microturbines can also be used for electricity generation from CH_4.[6] Project Type 2 is the generation of electricity using landfill or manure gas to displace onsite fossil fuel electricity generation. This project type avoids emissions from the fuel that would be used onsite.

Some projects may displace both onsite and offsite electricity generation. In cases where a portion of the electricity generated is used onsite, and a portion is sold to the grid, the project developer must account for the amount of electricity produced for use onsite, and the amount of fuels displaced by this application.

End Use Project Type 3—Delivery of captured methane into a pipeline system or simple conversion to Compressed Natural Gas (CNG) or Liquefied Natural Gas (LNG). Captured gas can be upgraded into high-Btu gas, compressed and injected into a natural gas pipeline or can undergo further conversion into LNG or CNG.

End Use Project Type 4—Other direct uses. Other direct uses consist of heating (e.g., furnaces, kilns, engines, space heaters) for various commercial and industrial uses, greenhouses, on-site leachate evaporation systems, and cooling (e.g., chillers, air conditioning). Only retrofit projects for Type 4 are eligible to use this protocol. At this point, baselines for new capacity for this project type have not yet been developed.

Project Size/Output. This accounting methodology applies to all CH_4 end use projects described above regardless of size.

Project Boundary. This section provides guidance on which physical components and associated GHGs must be included in the project boundary for CH_4 end use projects.

Physical Boundary. The physical boundary of the project includes any component of the project that will change between the baseline conditions and implementation of the project. This includes any equipment or processes that are integral to the project.

[6] When the output from the turbine is both electricity and steam for heating, it is referred to as combined heat and power (CHP) or cogeneration. The methodologies discussed in this paper do not apply to projects that employ cogeneration.

The physical boundary for end use of captured CH_4 for the production of electricity or heat or use in a pipeline includes equipment used in the following activities:

- gas clean-up prior to end use. Common clean-up equipment used in landfill gas and manure management gas systems include: 1) liquid separators and knockout vessels; 2) particle filters; 3) solvent absorption towers or vessels to remove impurities (e.g., selexol, diethanol amine (DEA), or methyldiethanolamine (MDEA) processes); 4) a molecular sieve unit to adsorb impurities; 5) membrane separation units; 7) cryogenic separation systems; and 8) H_2S scrubbers;
- compression to boost the gas pressure above the minimum acceptable input pressure for the combustion device or pipeline;
- the end use combustion device (e.g., engine, turbine, boiler, dryer, heater);
- any new sections of pipeline built to connect to existing distribution systems. The CH_4 leakage from these incremental sections should be accounted for;
- if the biogas is delivered to a pipeline, the boundary must include combustion of the natural gas in the baseline; and
- end use projects that generate electricity for onsite use, or heat for onsite or offsite use must include any existing sources that will be displaced by the project (e.g., any power generators or boilers and their associated fuel consumption whose use will be offset by the electricity or heat produced by the end use project).

Should the project require any additional equipment not listed above, this equipment must also be included in the project boundary, including any direct and indirect energy inputs required to operate the equipment, and any vented or fugitive emissions from it.

Greenhouse Gas Accounting Boundary. The GHG accounting boundary for end use of CH_4 includes the following sources:

- CO_2, CH_4 and N_2O from combustion of the fuels that provided the project's service prior to the project activity;
- direct and indirect emissions of CO_2, CH_4 and N_2O from operating various equipment during the clean-up and/or compression of the captured gas;
- direct emissions of N_2O from the combustion of captured gas in end use equipment; and

- direct emissions of N_2O from the combustion of end use gas injected into natural gas pipelines. Unless the project developer knows exactly what happens to the natural gas once it is injected, these emissions can be calculated using the default factors for N_2O emissions provided in Table IIa (Appendix II). In the absence of additional information on the end use of the gas, values provided for the industrial sector should be used.

Combusting CH_4 through end use technologies generates CO_2 with minor amounts of associated N_2O.[7] The CO_2 that results from the end use of CH_4 captured from landfills and manure management is considered biogenic, and therefore should not be included in the accounting boundary.[8]

Temporal Boundary. An annual accounting cycle should be used for CH_4 projects. The temporal boundary should also include the emissions associated with construction and operation of the gas collection system and the end use equipment (including retrofitting).

Leakage. Leakage is an increase in GHG emissions or decrease in sequestration caused by the project but not accounted for within the project boundary. The underlying concept is that a particular project can produce offsetting effects outside of the physical boundary that fully or partially negate the benefits of the project. Although there are other forms of leakage, for this performance standard, leakage is limited to activity shifting – the displacement of activities and their associated GHG emissions outside of the project boundary.

For end use projects, there is some potential for leakage of GHGs outside the project boundary. Potential sources of leakage from an end use project include:

- *Increased on-site energy use.* Lower on-site energy costs can result in increased and less efficient energy use. Therefore, a major reduction in on-site energy costs could result in significantly less efficient use of energy in space and water heating applications.

[7] Compared with natural gas, landfill and manure gases have a greater volume of impurities, such as nitrogen, CO_2, and moisture. As a result, these gases typically have about half the heat content of natural gas (approximately 500 Btu) and therefore burn in a boiler at a lower temperature than natural gas. In some cases, default emission factors based on natural gas may not be completely representative, and to the extent possible direct measurements should be used instead.

[8] According to the Intergovernmental Panel on Climate Change (IPCC (2006) 2006 IPCC Guidelines for National Greenhouse Gas Inventories,) and US EPA (2008) Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006 GHG accounting convention.

If it is determined that significant emissions that are reasonably attributable to the project occur outside the project boundary, these emissions must be quantified and included in the calculation of reductions. No specific quantification methodology is required. All associated activities determined to contribute to leakage should be monitored.

Regulatory Eligibility

The performance standard subjects greenhouse gas offset projects to a regulatory "screen" to ensure that the emission reductions achieved would not have occurred in the absence of the project due to federal, state or local regulations. In order to be eligible as a GHG offset project, GHG emissions must be reduced below the level effectively required by any existing federal, state, or local policies, guidance, or regulations. This may also apply to consent decrees, other legal agreements, or federal and state programs that compensate voluntary action.

If a landfill or farm is required to produce energy from the captured gas by any law, regulation, ordinance, etc., the project does not pass the eligibility screen.

> **Federal Regulations.** There are no federal regulations that affect the end use of CH_4 captured from landfills or manure management operations.
>
> **State and Local Regulations.** There are no known state or local regulations that directly require the end use of CH_4 collected from landfills or manure management operations.

Determining Additionality – Applying the Performance Threshold

This section describes the performance threshold (additionality determination) that a CH_4 end use project must meet or exceed in order to be eligible as a GHG offset project.

Additionality Determination. The additionality determination represents a level of performance that, with respect to emissions reductions or removals, or technologies or practices, is significantly better than average, compared with recently undertaken practices or activities in a relevant geographic area. Any project that meets or exceeds the performance threshold is considered "additional" or beyond that which would be expected under a "business-as-usual" scenario.

The performance standard for end use of CH_4 is separate from the performance standard for the capture and collection of the CH_4 gas itself. This separation allows additional reductions for heat and electricity end use projects that avoid the use of fossil fuels by using the captured CH_4, and also allows for reductions from energy use by projects where the combustion of CH_4 is not additional (such as in landfills required by NSPS to combust LFG). In the case of end use of captured CH_4, the performance threshold is based on the emissions rate from the type of fuel or energy input that will be avoided by operation of the project activity using CH_4. In many cases, the fuel or energy displaced by the project activity will be the mix of fuels that reflect regional supply, or industry process norms.

The end use of gas from landfills or manure management systems by the project passes the performance threshold in that the CO_2 emissions from the end use CH_4 are "zero-rated" by accounting convention and, therefore, the use of this gas represents a level of performance that is beyond that achieved with the use of conventional fuels. Only in a case where the current energy use is already a renewable energy source would there normally be an issue for a biogas use passing the performance threshold, For injection into a natural gas pipeline, it is known that only a very small percentage of existing gas is zero-rated, and less than 2% of onsite energy is generated from renewable sources.

End use projects using captured CH_4 are additional if the end use component of the project is not substituting for a renewable (zero-emissions) fuel source. Datasets presented below will provide background information for setting the baseline for each end use project type.

Quantifying Emission Reductions

Quantification of reductions from an end use project encompasses four steps; two are pre-project implementation (selecting the emissions baseline and estimating project emission reductions) and two are post-project implementation (monitoring and calculating actual reductions).

The data sets used to develop the baselines are different depending on the end use category, but have the following key principles in common:

1. They reflect, to the extent possible, the actual fuel choices that the project developer has *in lieu* of the end use project; and
2. They enable the selection of practices that represent significantly better than average performance in the category.

To address both of these principles simultaneously, it is necessary to develop "fuel-weighted" baselines. How this is accomplished will vary depending on the end use category as outlined below.

Selecting and Setting an Emission Baseline. Eligible projects will use different types of emission baselines, depending on whether the end use project involves the retrofit/replacement of existing equipment or the use of captured CH_4 in new equipment, meeting new demand. In all cases, the baseline reflects the service (i.e., heat or electric output) provided by the project activity and is represented in terms of baseline emission factors to determine emissions for this heat or electric output.

Baseline emission factors selected here will be used to calculate project emission reductions using monitored data from the project.

1. **Retrofit or Early Replacement:** For CH_4 end use projects involving conversion or early replacement of existing equipment to enable the use of captured CH_4, the baseline is equal to the average emissions rate of the fuels used in the *existing equipment* (i.e., the equipment prior to CH_4 use) in $kgCO_2$ equivalent per Btu or kWh.

   In cases where a retrofit project also expands capacity, the portion of the project that is above the baseline fuel consumption is treated as new capacity (see below).

   In the case where a retrofit involves the use of electricity from captured methane replacing direct fuel use, the project developer will need to determine the MMBtu that provide the equivalent services (usually established as the average rate over the previous three years) as the electricity. The same is the case for direct use of captured methane replacing onsite electricity production in a retrofit.

Table 1. Baselines for Retrofits Project Types 1-4

Project	Project Fuel Type	Baseline Weighted Fuel Average (Emissions per Heat Output ($kgCO_2$/MMBtu))
Retrofit	Natural Gas	53.06
Retrofit	Distillate Fuel Oil	73.15
Retrofit	Residual Fuel Oil	78.80
Retrofit	Coal	93.98

Source: Inventory of U.S. Greenhouse Gas Emissions and Sinks, and Table 1C, Appendix 1 of Climate Leaders Commercial Boiler Protocol.
Note that for electricity projects, kWh must be converted to MMBtu to use these factors.

2. **New Capacity or Replacement at End of Service Life:** For end use projects that involve new equipment to meet new capacity or replacement of existing equipment at the end of its service life, the emissions baseline should be equal to the fuel weighted average of the emissions avoided.

Table 2. Baseline for New Use Project Type 1

Project	Project Fuel Type	Baseline Weighted Fuel Average (Emissions per Heat Output ($kgCO_2$/MMBtu))
New Project Type 1	All fuels	66

Source: Inventory of U.S. Greenhouse Gas Emissions and Sinks, and Table 1C, Appendix 1 of Climate Leaders Commercial Boiler Protocol.
Note that for electricity projects, kWh must be converted to MMBtu to use these factors.

Table 3. Baseline for New Use Project Type 2

Census Region	States	Weighted CO_2 EF (kg/MMBtu)
Northeast	ME, NH, VT, MA, RI, CT, NY, PA, NJ	67.85
Midwest	OH, MI, IN, IL, WI, MN, IA, MO, ND, SD, NE, KS	83.15
South	DE, MD, DC, VA, WV, NC, SC, GA, FL, KY, TN, MS, AL, AR, LA, OK, TX	65.80
West	MT, WY, CO, NM, ID, UT, NV, AZ, CA, OR, WA, AK, HI	62.17

Source: Inventory of U.S. Greenhouse Gas Emissions and Sinks, and Table 1C, Appendix 1 of Climate Leaders Commercial Boiler Protocol.
Note that for electricity projects, kWh must be converted to MMBtu to use these factors.

Table 4. Baseline for New Use Project Type 3

Project	Project Fuel Type	Baseline Weighted Fuel Average (Emissions per Heat Output ($kgCO_2$/MMBtu))
New Project Type 3	Natural Gas	53.06

Source: Inventory of U.S. Greenhouse Gas Emissions and Sinks, and Table 1C, Appendix 1 of Climate Leaders Commercial Boiler Protocol.

Estimating Project Emission Reductions. To estimate the potential GHG emission reductions from the offset project, the project proponent must compare emissions of the baseline with the emissions of the proposed project.

Estimating baseline emissions: Separate equations are presented for estimating baseline emissions from retrofit projects (Equations A, B and C) and new capacity (Equations D, E, F, G, and H).

The baseline values for new capacity projects described in Appendix I are only based on CO_2 emissions. Emissions of CH_4 and N_2O must be added to the CO_2 emissions in order to estimate total CO_2 equivalent emissions from the baseline. The default emission factors for CH_4 and N_2O, listed in Table IIa and IIb (Appendix II), should be used to estimate the contribution of CH_4 and N_2O to baseline emissions. The default emission factors for indirect electricity consumed by project equipment are provided in Table IIc (Appendix II).

These emission factors should be multiplied by the annual heat requirement of the equipment (MMBtu/year) to estimate annual emissions in terms of CO_2 equivalent. The contribution of all three gases is then summed to determine total CO_2 equivalent baseline emissions for the year.

Retrofits

Equation A.

Baseline CO_2 emissions $_{retrofits}$ = $[(F_i * EF_i) + (EL * EF_{el})] * 0.001$

Where:

Baseline CO_2 emissions $_{retrofits}$ = baseline CO_2 emissions, MT

i= fuel type

F_i= fossil fuel consumption, MMBtu (use the average annual fuel consumption for the past three years)

EF_i = emission factor established for the fuel used in the baseline (kg CO_2/MMbtu)

EL= quantity of electricity consumed, MWh (use the average annual consumption for the past three years)

EF_{el} = baseline CO_2 emission factor for onsite electricity (kgCO_2/MWh)

0.001 = conversion from kg to MT, dimensionless

Equation B.

Baseline CH_4 and N_2O emissions $_{Retrofits}$= $((F_i * EF_{CH4}) + (F_i * EF_{N20}) + (EL * EF_{el, CH4}) + (EL * EF_{el, N2O})) * 0.001$

Where:

Baseline CH_4 and N_2O emissions $_{Retrofits}$=baseline CH_4 and N_2O, $MTCO_2e$

i= fuel type

F= fuel consumption, MMBtu (use the average annual fuel consumption during the past three years)

EF_{CH4}, EF_{N20}, = fuel-related CH_4 and N_2O emission factors, respectively, $kgCO_2e$/MMBtu

EL= quantity of electricity consumed, MWh (use the average annual consumption for the past three years)

$EF_{el,CH4}$, $EF_{el, N20}$= Electricity-related CH_4 and N_2O emission factors, respectively, $kgCO_2e$/MWh

0.001 = conversion from kg to MT, dimensionless

Equation C.

Total Baseline GHG Emissions $_{\text{Retrofits}}$ = Equation A + Equation B.

New Capacity

Total CO_2-equivalent emissions must also be calculated when estimating baseline emissions from new construction projects. In addition, baseline emissions associated with any increased energy generation above the 3 year average baseline constructed for retrofits will be calculated using these equations as well. As outlined below, formulas for calculating baseline CO_2 emissions for new construction are based on the fuel-weighted average emission factor for the particular project type. The calculation for non-CO_2 emissions follows Equation B above, but uses estimates for project-level fuel and electricity consumption.

Equation D (Project Type 1—Boilers)

Baseline CO_2 Emissions $_{\text{New Construction}}$ = (BP * F_i) * 0.001

Where:

BP = baseline performance - $kgCO_2$/MMBtu

F_i = estimated fuel consumption for project, MMBtu

0.001 = conversion from kg to MT, dimensionless

Equation E (Project Type 2— Displacing Onsite Electricity Generation)

Baseline CO_2 Emissions $_{New\ Construction}$ = ED * EF_{el} * 0.001

Where:

ED = estimated quantity of onsite electricity displaced, MWh

EF_{el} = emission factor for electricity, $kgCO_2$/MWh

0.001 = conversion from kg to MT, dimensionless

Equation F (Project Type 3—Delivery of LFG or MMG into a Pipeline System)

Baseline CO_2 Emissions $_{New\ Construction}$ = EF_{NG} * G_i * 0.001

Where:

EF_{NG} = CO_2 emission factor for natural gas (kg CO_2/MMBtu)

G_i = estimated amount of gas to be delivered to the pipeline (MMBtu)

0.001 = conversion from kg to MT, dimensionless

Equation G.

Total Baseline GHG Emissions $_{New\ Construction}$ = Equation D, E, F + Equation B.

Estimating project emissions: Project-related emissions are estimated using the same Equations above (i.e., Equations A, B and C for retrofits and Equations B, D, E, F, and G for new capacity). Similar to the baseline calculations, the estimated annual fuel consumption of the project is multiplied by the applicable CH_4 and N_2O emission factors. In this case, however, the project biogas has an emission factor of 0 kg CO_2/ energy or electrical output, as the CO_2 is biogenic.

Any fuel consumption for gas clean up and compression must be added to in Equations A, B, and D, E, and F. Emissions from purchased electricity also should be included to estimate total project-related CO_2 equivalent emissions.

Estimating project-related emission reductions: Emission reductions are estimated using Equation H.

Equation H. Reductions $_{project}$ = Emissions $_{baseline}$ – Emissions $_{project}$

Monitoring

Monitoring of end use projects is by direct measurements. Measurements should be taken of the volume of gas that flows to the end use device, and the CH_4 concentration of that gas. Electricity generation and use is metered.

All end use projects must also monitor any regulatory requirements (or changes in regulatory requirements) that might affect the continued eligibility of the project as a GHG offset project.

Monitoring Method for Determining MMBtu

The monitored value for MMBtu is determined by converting the volume of methane combusted by the project (i.e., $CH_4\ Combusted_{project}$ in Equation G) from SCF to MMBtu using a Higher Heating Value (HHV) of CH_4 of 993 Btu/SCF. This HHV for CH_4 was developed using standard properties for CH_4 at a reference pressure of 1.013 bar and reference temperature of 70F. The conversion from SCF to MMBtu is illustrated in Equation J.

Direct-measurement methods depend on two measurable parameters: 1) the rate of gas flow to the combustion device; and 2) the CH_4 content in the gas flow. These can be quantified by directly measuring the landfill gas stream to the destruction device(s).

Continuous Metering. The instrumentation recommended for continuous measurement measures both flow and gas concentration. Several direct measurement instruments also use a separate recorder to store and document the data.

A fully-integrated system that directly reports CH_4 content requires no other calculation than summing the results of all monitoring periods for a given year. Internally, the instrumentation is performing its calculations using algorithms similar to Equation I.

Monthly Sampling. The two primary instruments used in the monthly monitoring method are a gas flow meter and a gas composition meter. The gas flow meter must be installed as close to the gas end use device as possible to measure the amount of gas reaching the device. Two procedures are used for data collection in the monthly monitoring method:

1. Calibrate monitoring instrument in accordance with the manufacturer's specifications.
2. Collect four sets of data: flow rate (scfm); CH_4 concentration (%); temperature (^oR); and pressure (atm) from the inlet LFG or MMG gas (before any treatment equipment using a monitoring meter specifically for CH_4 gas.)

   The amount of CH_4 combusted during the month is calculated using Equation I. Monthly data for V, C, T, P and t are summed in order to calculate an annual total.

   Equation I.

   CH_4 Combusted$_{project}$ = V x (C/100) x 0.0422 x (520/T) x (P/1) x (t) x (0.454/1000)

   Where:

   V = Total volumetric flow in cfm

   C = CH_4 concentration of flow (in %)

   0.0423 = lb. CH_4/scf (at 520R or 60F)

   T = Temperature at which flow is measured (^oR)

   P = Pressure at which flow is measured (atm)

   t = Time period since last monthly measurement (min)

   0.454/1000 = Conversion factor, lbs. to metric tons

Equation J.

MMBtu$_{project}$ = CH_4 Combusted$_{project}$ x 993 Btu/scf

Monitoring Method for Determining MWh
The monitored values for MWh can be read directly from separate watt-meters installed for the project. The watt-meters will typically already be required by the utility to meet accuracy requirements.

Calculating Actual Project Reductions. Quantifying project GHG emissions reductions occurs after the project has been implemented and monitored. To quantify project reductions, apply the equations presented in the section on estimating project emission reductions, using actual monitored project data rather than estimates, and adjust for any leakage (Equation K). Use baseline equations with baseline emission factors and the monitored values for MMBtu or MWh provided by the project fuel to determine baseline emissions.

Equation K.

$$\textbf{Reductions}_{\text{project}} = \textbf{Emissions}_{\text{baseline}} - \textbf{Emissions}_{\text{monitored}} \; \textbf{(+/- leakage adjustments)}$$

Appendix I. Datasets for Baselines

The following appendix describes the data used to develop the baselines for new end use Project Types 1, 2, 3, and 4.

Project Type 1—Generation of hot water or steam from boilers

Commercial and Industrial Boilers

The two datasets referenced in developing the baselines for new commercial boiler projects are the New Jersey Electric & Gas Utilities: *Commercial Energy Efficient Construction Baseline Study* and the U.S. Energy Information Administration's *Commercial Buildings Energy Consumption Survey (CBECS).*[9] In addition, background information derived from two state energy efficiency programs contributed to the analysis.

The New Jersey study, which involved on-site audits of 96 new commercial buildings in 1999, showed that fuel oil boilers were used in only 3% of new construction and renovation. The remainder was gas and electric. Meanwhile, EIA's CBECS showed a decreased fraction of fuel oil used in building boilers in all U.S. regions over the past 70 years. The analysis also indicated that the overall penetration of renewable energy in the commercial sector is low. According to EIA, in 2003 only a small fraction (0.7%) of buildings used municipal solid waste or landfill gas to fire their boilers. There is growing interest in biodiesel. There was no available data, however, to include this fuel in the analysis.

The data sources used for developing the baseline for new industrial boiler projects include the California Energy Commission's *Non Residential Market Share Tracking Study* published in April 2005, the U.S. Energy Information Administration's (EIA) *Manufacturing Energy Consumption Survey (MECS)* last updated in 2002, and Oak Ridge National Laboratory's (ORNL) *Characterization of the U.S. Industrial Commercial Boiler Population* published in May 2005.[10] In addition, information on current engineering practices concerning industrial boilers were used, focusing on boilers installed in New York, Wisconsin, and California.

The EIA MECS 2002 survey includes data on all market fuels and electricity used by industrial boilers, but excludes by-product fuels. It shows that in 2002 natural gas was the predominant fuel regardless of region or location, representing 78% of the total fuel consumed by industrial boilers. Coal made up another 15% and fuel oil about 6%.

---

[10] Climate Leaders, "Project Type: Industrial Boiler Efficiency (Industrial Process Applications)," Draft Offset Protocol, U.S. Environmental Protection Agency.

Recent engineering practices in states such as California, Wisconsin, and New York indicate that use of natural gas is even more prevalent in industrial boilers that have been installed within the past five years. For example, the CEC *Non Residential Market Share Tracking Study* shows that 100% of new industrial boiler applications installed in the years 2000-2002 used natural gas as the primary fuel.

Spatial Area – A national spatial area was used to develop the baseline for new commercial boiler projects. One baseline was initially developed for each of the regions in the United States (Northeast, Midwest, South and West) in the belief that regional fuel availability might impact the regional emission rates of boilers. The results of this analysis, however, show that three out of the four regions had the same emissions rate, the South being the exception with a higher emissions rate. Therefore, a national spatial range was selected for all new commercial boiler projects.

A national spatial area was also used to develop the baseline for new capacity industrial boiler efficiency projects. In the past five years, the predominant fuel used in new industrial boilers in all regions is natural gas.

Temporal Range – The temporal range for new construction commercial boiler projects is based on the performance of commercial boilers operating in the United States between 1990 and 2003 (the most recent years for which data are available). Although minimum efficiency standards on the Federal level for commercial boilers have remained unchanged since adoption of ASHRAE Standard 90.1-1999, data show that the overall fuel mix in boilers has changed slightly, with a decrease in the use of fuel oil partially being offset by an increased use of electricity (a portion of which is generated by coal).

The temporal range for new industrial boiler projects is five years. The CEC Non Residential Market Share Tracking Study and engineering practices in New Jersey, New York and Wisconsin indicate that, recently, industry has mostly invested in natural gas-fired boilers rather than coal or fuel oil boilers. Therefore, a temporal range using current engineering practices for industrial boilers (during the past five years) is appropriate.

Project Type 2— Generation of electricity (Displacing onsite fossil fuel use).

The data source used to develop the baseline for onsite generation of electricity (displacing onsite fossil fuel use) is the Energy Information Administration's Manufacturing Energy Consumption Survey (MECS). MECS data from 2002 were used as it is the most recent published survey. MECS provides detailed information on industrial energy and fuels used by region, and by industry sector and subsector in the US.

The MECS data from 2002 were then analyzed for the uses of cogeneration and other onsite generation. Other onsite generation is labeled as "conventional" electricity generation in MECS. MECS does indicate differences in fuels used for onsite generation between industry sectors; however, there are gaps in a number of industrial sectors that prevent a detailed comparison. The MECS data were then analyzed by Census region and significant differences were found – most notably the high use of coal as a fuel for onsite generation in the Midwest as is shown in Table Ia.

Table Ia. Percent Fuel Type Consumed for On Site Generation - 2002

Census Region	Total Fuel Consumption, trillion BTU	Residual Fuel Oil	Distillate Fuel Oil (a)	Natural Gas (b)	Coal (c)
United States	**1,509**	**3.45%**	**0.69%**	**60.44%**	**35.45%**
Northeast	**127**	**11.81%**	**2.36%**	**58.27%**	**27.56%**
Midwest	**253**	**3.16%**	**0.00%**	**25.30%**	**71.54%**
South	**1,011**	**2.57%**	**0.89%**	**67.46%**	**29.08%**
West	**118**	**1.69%**	**0.00%**	**77.12%**	**21.19%**

Source: EIA, 2002, 1998. MECS, Table 5.8.

The MECS data were also reviewed for the current use of biogenic gases from landfills or agriculture. MECS does not specifically categorize the energy consumed by these fuels, and considers them another combustible fuel; however, MECS does have a category for onsite generation by renewable sources which includes biogenic gases. Table 11.3 of MECS provides a breakdown of onsite renewable energy by region and by industry. For the US as a whole, 1.8% of onsite generation is from renewable sources. Ninety four percent of this renewable generation is reported from the pulp and paper industry and is most likely from co-located hydropower (wood and biomass are excluded from MECS Table 11.3). These data suggest that the use of biogenic gases in onsite generation is currently a very small portion of onsite generation and does not represent a common practice.

Spatial Area. Both regional and national spatial areas were analyzed to develop the baseline emissions factors. A regional spatial area was selected to develop the baseline because fuel choices, fuel availability, and permitting requirements for onsite power vary regionally. There are some areas within these regions – certain severe and extreme ozone non-attainment areas – in which permitting requirements for new onsite generation would preclude any fuel use other than natural gas. For these cases, the natural gas emission factor for baseline emissions should be used.

Temporal Range. MECs data from 2002 and the most recent EPA emission factors (2006) for natural gas, coal, distillate and residual fuel oils were used to develop the baseline emission factors. The emission factors presented above in Table represent weighted regional averages for the fuels used for onsite generation.

Project Type 3—Injection into an existing natural gas pipeline or conversion to LNG or CNG

The data sources used to develop the baseline for captured CH4 injected into an existing natural gas pipeline or conversion to LNG/CNG include EPA's Landfill Methane Outreach program (LMOP) database from June 2006 and EPA's AgStar Digest from 2005.

Although sometimes called the natural gas "grid," regional emission factors are not relevant for pipeline gas, since the fuel has not yet been combusted and end use has not yet occurred. The simple assumption is that biogenic gases from captured CH_4 end use projects always "displace" conventional natural gas sources in the pipeline. There are more than 20 landfill gas projects placing gas into pipelines in the United States.[11] Given this small number of projects, the data indicates that the overall volume of landfill gas in the pipeline network is insignificant. In the future, this may not always be the case if significant quantities of biogenic gases begin entering the grid and pipeline operators begin "bumping" other biogenic sources off the network.

The data sources used to develop the baseline for captured gas CH_4 injected into an existing natural gas pipeline or conversion to LNG/CNG include EPA's Landfill Methane Outreach program (LMOP) database from June 2006 and EPA's AgStar Digest from 2005.

Spatial Area. A national spatial area was used to develop the baseline.

Temporal Range. The most recent EPA emission factors (April 2006) for natural gas were used to develop the baseline.

Project Type 4—Other direct uses

The baseline for other direct uses is the fuel used to provide the service in the baseline. A baseline emission rate per unit of product for the previous 3 years (if available) could be developed. Alternatively, the baseline could be the annual emission per year for the previous 3 years**.**

[11] http://www.epa.gov/lmop/proj/index.htm. Accessed April 14, 2008.

Appendix II. Default Emission Factors

Table IIa. Default CH_4 and N_2O Emission Factors for Natural Gas, Fuel Oil, and Coal

Fuel Type	Greenhouse Gas	Emissions per Unit of Fuel Input (kg CO_2e/MMBtu)
Natural Gas	CH_4	0.105
	N_2O	0.031
Petroleum (Commercial sector)	CH_4	0.231
	N_2O	0.186
Petroleum (Industrial sector)	CH_4	0.063
	N_2O	0.186
Coal	CH_4	0.231
	N_2O	0.496

Sources: Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2006. U.S. Environmental Protection Agency, April 2008.

Table IIb. Default CH_4 and N_2O Emission Factors for Electricity

Fuel Type	Greenhouse Gas	Emissions per Unit of Fuel Input (kg CO_2e/MMbtu)
Natural Gas	CH_4	0.021
	N_2O	0.031
Petroleum	CH_4	0.063
	N_2O	0.031
Coal	CH_4	0.021
	N_2O	0.496

Note: Electricity emissions of CH_4 and N_2O relate to the fuel used to produce the electricity. Information on fuel type will be needed to estimate CH_4 and N_2O.
Sources: Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2006. U.S. Environmental Protection Agency, April 2008.

Table IIc. Emission Factors for Electricity Use by Project Equipment by eGRID Subregion (2004)

eGRID Subregion	States included in eGRID Subregion	NERC Region	Emission factor for electricity used by project equipment (kg CO2/kWh)
AKGD* (Alaska Grid)	AK	ASCC	0.604
AKMS (Alaska Miscellaneous)	AK	ASCC	0.630
AZNM (WECC- Southwest)	AZ, CA, NM, NV, TX	WECC	0.634
CAMX (WECC- California)	CA, NV, UT	WECC	0.572

ERCT (Texas)	TX	ERCOT	0.600
FRCC (Florida)	FL	FRCC	0.612
HIMS (Hawaii- Miscellaneous)	HI	HICC	0.738
HIOA* (Hawaii- Oahu)	HI	HICC	0.783
MORE (Midwest- East)	MI, WI	MRO	1.005
MROW (Midwest- West)	IA, IL, MI, MN, MT, ND, NE, SD, WI, WY	MRO	1.050
NEWE (New England)	CT, MA, ME, NH, NY, RI, VT	NPCC	0.641
NWPP (WECC- Northwest)	CA, CO, ID, MT, NV, OR, UT, WA, WY	WECC	0.770
NYCW (New York- NYC, Westchester)	NY	NPCC	0.788
NYLI (New York- Long Island)	NY	NPCC	0.686
NYUP (New York- Upstate)	NJ, NY, PA	NPCC	0.821
RFCE (RFC- East)	DC, DE, MD, NJ, PA, VA	RFC	0.800
RFCM (RFC- Michigan)	MI	RFC	0.880
RFCW (RFC- West)	IL, IN, KY, MD, MI, OH, PA, TN, VA, WI, WV	RFC	0.951
RMPA (WECC- Rocky Mountains)	AZ, CO, NE, NM, SD, UT, WY	WECC	0.778
SPNO (SPP- North)	KS, MO	SPP	1.007
SPSO (SPP- South)	AR, KS, LA, MO, NM, OK, TX	SPP	0.699
SRMV (SERC- Mississippi Valley)	AR, LA, MO, MS, TX	SERC	0.634
SRMW (SERC- Midwest)	IA, IL, MO, OK	SERC	0.979
SRSO (SERC- South)	AL, FL, GA, MS	SERC	0.847
SRTV (SERC- Tennessee Valley)	AL, GA, KY, MS, NC, TN	SERC	0.941
SRVC (SERC- Virginia/Carolina)	GA, NC, SC, VA, WV	SERC	0.890

Note: The emission factors in Table IIc reflect variations in electricity use by project equipment across regions and load type (i.e., base versus non-baseload). Coincident peak demand factors from a 2007 ACEEE study were combined with EPA's eGRID emission factors for baseload and non-baseload power to derive the emission factors presented in this table.[12,13]

---

[12] *York, D. Kushler, M. Witte, P. "Examining the Peak Demand Impacts of Energy Efficiency: A Review of Program Experience and Industry Practice." American Council for and Energy-Efficient Economy (ACEEE). February 2007. http://www.aceee.org/pubs/u071.htm.*

[13] The Emissions & Generation Resource Integrated Database (eGRID) is a comprehensive inventory of environmental attributes of electric power systems, available at http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.