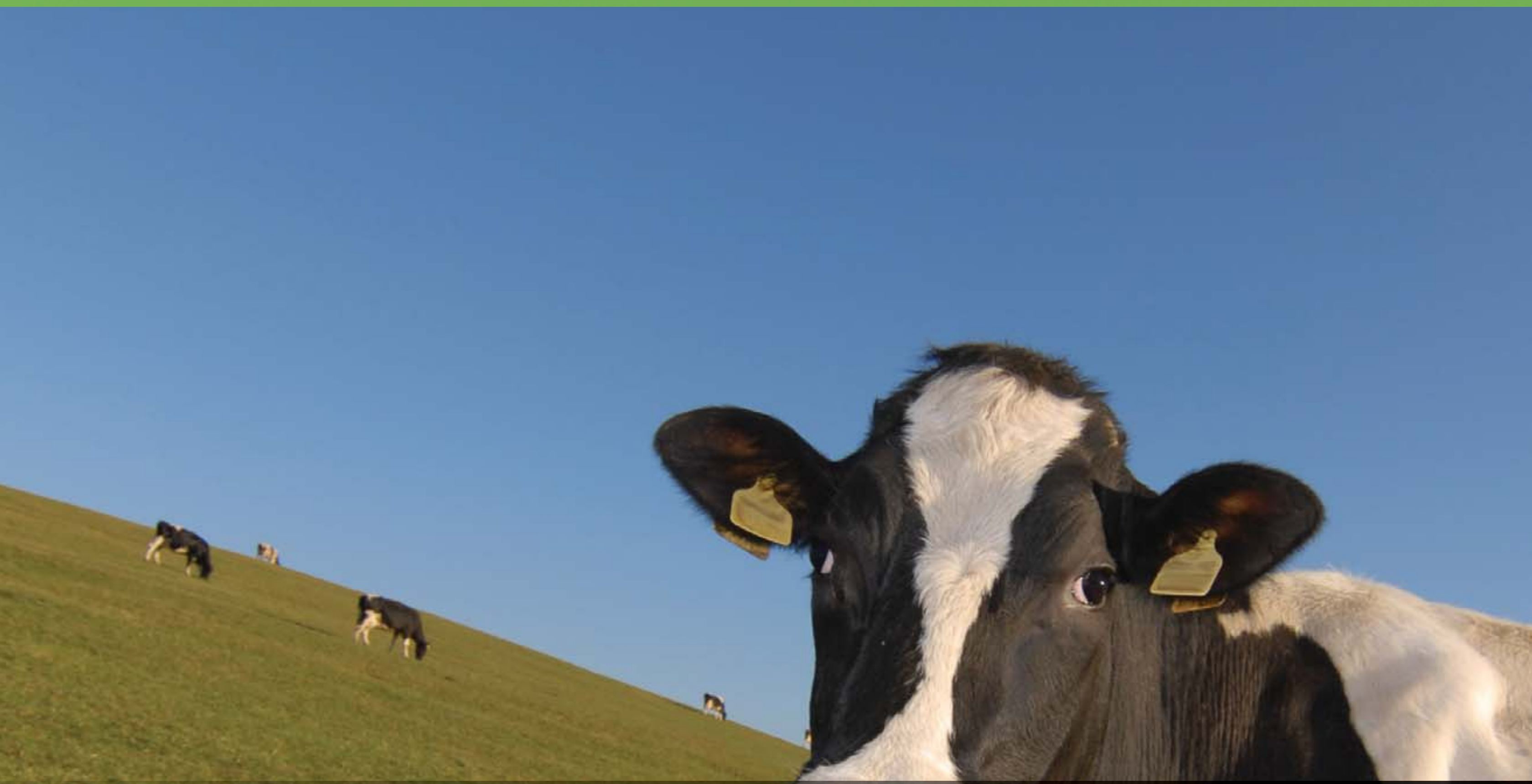
Chicago Climate Exchange®

Agricultural Methane Collection and Combustion Offset Project Protocol



Agricultural Methane Collection and Combustion Offset Projects

The Chicago Climate Exchange (CCX®) Agricultural Methane Collection and Combustion Offset Project Protocol outlines the process and requirements for Project Proponents to register greenhouse gas emission reductions resulting from the voluntary destruction of methane originating from animal agricultural operations. CCX General Offsets Program Provisions, CCX Offset Project Verification Guidance Documents and CCX Offset Project Protocols can be downloaded by visiting www.theccx.com. Requests for further information or comments may be directed to offsets@theccx.com.

CHICAGO CLIMATE EXCHANGE OFFSET PROJECT PROTOCOL

Agricultural Methane Collection & Combustion

Updated as of 9/30/2009

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ACRONYMS, TERMS AND DEFINITIONS[1]

ANSI	American National Standards Institute
CCX	Chicago Climate Exchange
EPA	Environmental Protection Agency
GCCS	Gas Collection and Control System
GHG	Greenhouse Gas
IPCC	Intergovernmental Panel on Climate Change
USDA	United States Department of Agriculture
WBCSD	World Business Council on Sustainable Development
WRI	World Resources Institute

Agricultural Methane:	Methane produced and emitted during the anaerobic decomposition of organic material in livestock manure.
Anaerobic Lagoons:	A waste management system found in various agricultural applications that is designed and operated to combine waste stabilization and storage. Anaerobic lagoons create an environment necessary for anaerobic digestion (breakdown of organic matter by microorganisms in the absence of oxygen). Anaerobic lagoons result in the creation of biogas.
Biogas:	A mixture of gas, primarily made up of methane, produced by the anaerobic breakdown of organic matter.
Gas Collection and Control System (GCCS):	A network of wells and/or piping to create a pathway for gas migration towards a combustion or non-combustion technology to mitigate emissions, pollutants and/or odor.
Liquid/Slurry:	A manure management system where manure is stored as excreted or with some minimal addition of water to facilitate handling and is stored in either tanks or earthen ponds, usually for periods of less than one year.
Pit Storage Below Animal Confinement:	Collection and storage of manure usually with little or no added water typically below a slatted floor in an enclosed animal confinement facility. Typical storage periods range from 5 to 12 months, but must exceed one month.
Solid Separation:	Removal of water from manure, resulting in a liquid and manure solids.

[1] Please refer to CCX General Offsets Program Provisions for additional "Acronyms, Terms and Definitions"

1. Introduction

Chicago Climate Exchange (CCX) is the world's first and North America's only active voluntary, legally binding integrated trading system to reduce emissions of all six major greenhouse gases (GHGs), with Offset Projects worldwide. CCX Members with significant GHG emissions voluntarily enter into a legally binding agreement to reach CCX GHG Emission Reduction Commitment[2]. Upon enrollment with CCX, Exchange Allowances are issued to Members in amounts equal to their emission reduction targets. CCX Exchange Offsets are issued to Owners or Aggregators of registered Projects on the basis of verified sequestration, destruction or reduction of GHG emissions not included under the CCX Emission Reduction Commitment. Members are required to turn in the amount of Exchange Allowances and/or Exchange Offsets equal their actual GHG emissions annually.

CCX strives to promote transparency and integrity in the carbon market. In accordance with this goal, in developing this document, CCX was guided by the fundamental principles of Project GHG accounting outlined in ISO 14064-2: *Specification with guidance at the Project level for quantification, monitoring and reporting of greenhouse gas emission reductions or removal enhancements*, Version 1. These principles include:

- Relevance
- Completeness
- Consistency
- Accuracy
- Transparency
- Conservativeness

The following sections of this Protocol discuss the Project criteria, boundaries, monitoring requirements, emissions reduction calculations and other guidelines that each Project Proponent must adhere to in order to generate Exchange Offsets from agricultural methane collection and combustion Projects.

2. General Provisions

Offset Project eligibility is subject to the CCX General Offset Program Provisions and CCX Offset Project Protocol for Agricultural Methane Collection and Combustion Offset Projects, and the determinations of the CCX Committee on Offsets. Project Proponents should review CCX General Offset Program Provisions and CCX Offset Project Protocol for Agricultural Methane Collection and Combustion Offset Projects.

[2] http://theccx.com/content.jsf?id=72

3. ASSOCIATED DOCUMENTS

This Protocol references the use of several associated documents. These documents include:

- CCX General Offset Program Provisions
- CCX General Verification Guidance Document
- CCX Project Implementation Document
- CCX Project Specific Conflict of Interest Form
- CCX Greenhouse Gas Emission Factors Document
- CCX Project Owner Attestation

These documents are available on the Offsets section of the CCX website: www.theccx.com

4. PROJECT DEFINITION

An Agricultural Methane Collection and Combustion Offset Project consists of the installation and operation of a new agricultural methane gas collection[3] and control system (GCCS) that meets the eligibility criteria and other requirements outlined in these guidelines.

5. ELIGIBILITY CRITERIA

Several factors determine a Project's eligibility for generating Exchange Offsets including Proponent's membership status, ownership status, Project start date, location and whether the Project meets the CCX performance benchmark. Project Proponents should submit the CCX Project Information Document (PID) to CCX for review and determination of eligibility.

5.1 CCX Membership

The Project Proponent must be a Member or Participant Member (Offset Provider or Aggregator) of CCX. Project Proponents should contact CCX directly for membership rules and information.

5.2 Eligibility Governing Entities with Minor Emissions

Entities with an entity-wide emissions profile greater than 10,000 metric tons CO_2 equivalent for the most recent calendar year may register and trade CCX Exchange Offsets only if the entity is a Member of CCX and undertakes the CCX Emission Reduction Commitment. For specific guidance on this provision, Project Proponents should review CCX General Offset Program Provisions.

[3] Agricultural methane collection systems include various anaerobic digester systems such as complete mix, plug flow, and covered lagoons.

Entities who are unsure of their emissions profile should estimate their direct CO_2 emission using well accepted methodologies such as those available at the World Resources Institute (WRI)/World Business Council on Sustainable Development (WBCSD). CCX requires that all entities that are not Members, including producers enrolled with Aggregators, provide an attestation relating to their direct emissions in a form provided by CCX.

Project Emissions shall be calculated in accordance with the CCX Project Emissions Guidance Document. Fossil fuel emissions factors are available at http://www.theccx.com/docs/misc/GHG_Emission_Factors.pdf.

For specific guidance on this provision, Project Proponents should review the CCX General Offset Program Provisions.

5.3 Ownership and Control

The Project Owner must demonstrate clear ownership of the GHG mitigation rights associated with the Project in order to register the Offsets with CCX.

CCX Offset Aggregators must have acquired appropriate control of the GHG mitigation rights from the Project Owner in order to execute its responsibilities on CCX pursuant to CCX General Offset Program Provisions. Aggregators must demonstrate to the Project CCX-Approved Verifier contracted to perform verification services for the Project and to CCX that they have acquired appropriate control for trading of Exchange Offsets associated with the Project activity. This may be demonstrated through a mandate from the Project Owner providing the Aggregator the rights to register and trade Exchange Offsets on behalf of the Project Owner.

5.4 Project Start Date

Projects must start on or after January 1, 2003, which corresponds with the beginning of the CCX cap and trade program.

5.5 Project Location

Agricultural methane Projects shall be located either in the United States or in a country designated as a non-Annex I country under the Kyoto Protocol.

5.6 Performance Benchmark

Agricultural methane Projects are not eligible to generate Exchange Offsets in instances where the collection and destruction of agricultural methane gas can be considered a standard business practice (i.e. business as usual) or is required by law or other legally binding framework. CCX has identified two performance criteria that Projects must meet to be considered for Exchange Offset issuance.

5.6.1 Regulatory Criteria

In order to be eligible to receive Exchange Offsets under these guidelines, the Project shall not be required to collect and destroy agricultural methane gas under any federal, state or local regulations or other legally binding framework. The regulatory criteria must be applied to both U.S. and non-U.S.-based Projects (approved Projects originating in non-Annex I Kyoto Protocol countries).

During the course of verification, the Project Proponent shall provide to the Verifier reasonable assurances necessary to demonstrate that the Project is not required under any federal, state or local regulation or other legally binding framework and shall sign an attestation stating that the Project is not required under any federal, state, or local regulation or other legally binding framework.

5.6.2 Common Practice Criteria

According to the GHG Protocol for Project Accounting, "*Common practice refers to the predominant technologies or practices in a given market, as determined by the degree to which those technologies or practices have penetrated the market (defined by a specified geographic area).*"[4] CCX reviewed information regarding the prevalence of anaerobic digesters at dairy and swine farms in the United States. The United States Environmental Protection Agency (US EPA) AgStar Program gathers information on farms in the US and their manure management systems. Based on EPA AgStar and US Department of Agriculture (USDA) data, only 0.06% of dairy and swine farms in the United States have anaerobic digesters currently in operation. This information is summarized in the table below.

Table 1: Anaerobic Digesters at Dairy and Swine Farms

Type of Farm	Number of US Farms[5]	Number of farms with anaerobic digester[6]	Percent of US farms with anaerobic digester
Dairy	91,989	93	0.1
Swine	78,895	20	0.02
Total	**170,884**	**113**	**0.06**

Given the common practice definition above, installation of anaerobic digesters at unregulated farms in the United States is clearly not common practice. Therefore, a Project that meets the regulatory criteria above and installs an anaerobic digester or similar GCCS can be considered beyond business as usual. For Projects in non-Annex 1 countries under the Kyoto Protocol, the Project Proponent must similarly demonstrate that the Project activity is

[4] World Resources Institute and World Business Council for Sustainable Development. 2005. *The Greenhouse Gas Protocol for Project Accounting*. WRI/WBCSD, Washington, D.C.
[5] USDA, 2002, Census of Agriculture
[6] EPA AgStar Program. *Guide to Anaerobic Digesters*. December 2008. Accessed online at http://www.epa.gov/agstar/operational.html on January 9, 2009.

beyond business as usual. CCX will periodically review this data to assess whether the performance benchmark has changed and may implement modifications in the future based on the review. Once a Project is registered with CCX, it is not affected by changes to the common practice criteria for the market period in which it registers. The current market period is from January 1, 2003 through December 31, 2010.

6. PROJECT BOUNDARY

A clearly defined boundary is vital to accurately assessing emission reductions due to the installation of a GCCS. Although the destruction method may vary, the Project Boundary for agricultural methane Projects will include the agricultural methane collection system, equipment used for upgrading the collected gas, monitoring and recording equipment and destruction device(s).

6.1 Identification of GHG Sources, Sinks and Reservoirs

The following table identifies relevant GHG Sources and whether each is to be included within the Project's Boundary.

Table 2: Relevant GHG Sources to be Included within the Project's Boundary

GHG Source Category	GHG Source	GHG	Included in Project Boundary	Comment[7]
Agricultural Methane Collection and Upgrading Systems	Emissions resulting from fossil fuel derived energy used by, inter alia, compressors, blowers, and monitoring system	CO_2	Yes	All CO_2 emissions (direct and indirect) due to fossil fuel combustion are required to be included.[8]
		CH_4	No	Excluded, as this emission source is assumed to be very small.
		N_2O	No	Excluded, as this emission source is assumed to be very small.
Agricultural Methane Gas Destruction Device	Emissions resulting from the destruction of agricultural methane gas	CO_2	No	Biogenic emissions are excluded.
		CH_4	Yes	Dependent on efficiency of the destruction device.
		N_2O	No	Excluded, as this emission source is assumed to be very small.
	Emissions resulting from the combustion of fossil fuel in the destruction	CO_2	Yes	All CO_2 emissions (direct and indirect) due to fossil fuel combustion are included.

[7] Based on emissions factors found in Volume 2, Table 2.2 of the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, all CH_4 and N_2O emissions are excluded (with the exception of CH_4 emissions from agricultural methane gas destruction), as emissions will be small in comparison to CO_2 emissions.

[8] See Project Emissions discussion in this section for exceptions of the inclusion of indirect emission sources.

	device	CH_4	No	Excluded, as this emission source is assumed to be very small.
		N_2O	No	Excluded, as this emission source is assumed to be very small.

The GHG Sink(s) will be the combustion process and associated destruction device(s) used by the Project. No Reservoirs are anticipated in agricultural methane Projects and therefore are not discussed at greater length below.

ISO 14064-2 requires that the Project's GHG Sources and Sinks be categorized as controlled by the Project Proponent, related to the Project, or affected by the Project. These are discussed below.

6.1.1 Controlled GHG Sources and Sinks

Controlled GHG Sources and Sinks for agricultural methane Projects are those that occur on-site. Therefore, Controlled GHG Sources and Sinks for agricultural methane Projects refer to those that are part of the agricultural methane collection and upgrading systems and the agricultural methane destruction device.

6.1.2 Related GHG Sources and Sinks

Related GHG Sources and Sinks for agricultural methane Projects refer to those that have material or energy flows into or out of the Project. Therefore, Related GHG Sources and Sinks are the electricity grid that supplies electricity to the Project (if applicable) and the natural gas pipeline that conveys upgraded agricultural methane gas to an end user's destruction device (if applicable).

6.1.3 Affected GHG Sources and Sinks

Affected GHG Sources and Sinks are those that are influenced by the agricultural methane Project and result in new or changed activities outside the Project Boundary that actually increase GHG emissions. This concept is commonly referred to as leakage. CCX does not expect agricultural methane Projects to result in new or changed activities that increase GHG emissions outside of the Project Boundary and, therefore, no Project specific leakage assessment is required.

6.2 Determining the Baseline Scenario

In accordance with the process outlined in ISO 14064-Part 2, possible baseline scenarios were evaluated for agricultural methane Projects. CCX identified two plausible baselines for new agricultural methane Projects:

1. The unmitigated release of methane to the atmosphere.
2. The voluntary installation of a GCCS without the generation of revenue from Offsets.

Based on the information presented in Section 5, the most likely baseline scenario in the absence of regulation or other requirement mandating installation is the unmitigated release of methane to the atmosphere.

The unmitigated release of methane to the atmosphere results from manure management practices (as defined in the Intergovernmental Panel on Climate Change (IPCC) 2000 Good Practice Guidance document, the IPCC 2006 Guidelines, and as further clarified below) where manure is handled as a liquid and with significant methane emitting potential. Therefore, Projects must have one of the following baseline manure management practices:

- Liquid Slurry;
- Pit storage below animal confinement; or
- Anaerobic lagoon.

Manure management systems that utilize flush technologies to handle manure, or that combine scraped (or vacuumed) manure with more than minimal quantities of water in storage (for example, by mixing dairy parlor waste water with manure for handling or storage), and that have liquid manure storage systems with hydraulic retention times of greater than 90 days, may be categorized as "anaerobic lagoon" systems for baseline determination.

Eligible Projects with baseline manure management systems other than those listed above may include only that portion of the manure handled by eligible systems in any baseline emission and Exchange Offset calculation.

The GHG Sources, Sinks and Reservoirs identified in this baseline are limited to the GHG emissions from the pre-Project manure management system. For Projects developed on recently established farms, baseline manure management systems should represent the prevailing regional manure management systems for similar farm types.

6.3 Project Emissions

In cases where Project emissions *are not* included in a legally binding emission reduction program (such as an electric utility cap and trade scheme), they shall be included as Project emissions and subtracted from Project emission reductions as provided in section 8 below. Where Project emissions *are* included within a legally binding emissions reduction program, they may be omitted from the Project emissions calculation. Only those specific sources included under the capped portion of an emissions reduction program may be omitted. All other sources must be included.

Project emissions sources include, but are not limited to, the use of electricity from the grid, the consumption of purchased steam or heat, and the combustion of fossil fuel by the collection equipment or destruction device. Emissions associated with the preparation of agricultural methane gas for injection to a natural gas pipeline are included within the Project Boundary and shall be counted as a Project emissions source. Since carbon dioxide emissions from these sources are of much greater magnitude than emissions of other GHGs, only carbon dioxide emissions shall be included as Project emissions.

7. MONITORING REQUIREMENTS

The Project Proponent shall develop and maintain a monitoring plan with procedures for obtaining, recording, compiling and analyzing data and information required for quantifying and reporting GHG emission reductions.

Agricultural methane Project monitoring includes the following parameters:

- Daily totals of continuous biogas flow with monthly temperature and pressure monitoring to each combustion device.[9]
- Methane content analysis using a continuous gas analyzer or a portable gas analyzer, or gas sampling for independent laboratory analysis according to ASTM D-1946 or other appropriate standard.
- Electricity production (if applicable).
- Destruction device operating hours.
- Project-related emissions.

Section 8 presents two alternatives for calculating the GHG emission reductions for an agricultural methane Project. In the first alternative, biogas flow and methane content data are used while in the second, electricity production data is used to calculate the amount of methane destroyed.[10] Monitoring data shall be maintained to support the calculation to be used by the Project.

7.1 Flow Monitoring

Biogas flow shall be continuously read by an acceptable flow meter and should be tabulated daily. The flow meter shall be installed along the header pipe at a location that provides a straight section of pipe sufficient to establish laminar gas flow.

7.1.1 Flow Meter Performance Standard

The following information regarding flow meter performance shall be maintained:

- Manufacturer specifications of flow meter accuracy should be +/- 5% of reading.
- Proof of initial calibration.
- Capability to read flow every 15 minutes.
- Means to correct for temperature and pressure.

[9] Separate monitoring of temperature and pressure is not required when using flow meters that standardize based on temperature and pressure and present flow rate in standard cubic feet per minute (SCFM).
[10] This methodology is employed by the USEPA in the Inventory of U.S. Greenhouse Gas Emissions and Sinks (1990-2007) to estimate methane emissions avoided through landfill gas-to-energy Projects.

7.1.2 Flow Meter Calibration

It is essential that flow meters operate properly in order to accurately quantify GHG emission reductions. To ensure proper flow meter function, annual calibration of the flow meter shall be performed unless otherwise specified by the manufacturer. Flow meter calibrations must meet the following conditions:

- Calibrations must be performed in accordance with manufacturer's specifications and methodologies.
- Calibrations must be performed by the manufacturer, an ISO 17025 certified calibration and testing organization, or other appropriately trained personnel.
- All records of calibration reports and methodologies must be documented and made available for review during the verification process.

If manufacturer specifications state that the flow meter must be calibrated more often than annually, then the calibration schedule as recommended by the manufacturer shall be followed and the above conditions applied.

7.1.3 Flow Meter Location

The flow meter shall be installed at a location that provides a straight section of pipe sufficient to establish laminar gas flow as turbulent flow resulting from bends, obstructions, or constrictions in the pipe can cause interference with flow measurements that rely on differential pressure. Alternatively, a flow meter may be installed where there is not laminar flow, provided the technology is proven to be accurate under such conditions and the location of the installation has been specifically approved by a professional engineer to provide accurate flow meter readings. Flow meters shall be located such that the quantity of agricultural methane gas being consumed by each destruction device can be continuously and accurately measured.

7.2 Methane Content Analysis

Methane content measurements shall be taken and recorded on at least a quarterly basis using a portable gas analyzer or by laboratory analysis of sampled gas.

7.2.1 Gas Analyzer Performance Standard

The gas analyzer used shall meet the following performance standards:

- Precision: Methane measurements are to be to the nearest 0.1 percent.
- Accuracy: Methane measurement accuracy decreases with increasing methane concentration but should be within +/- 10% of reading, as specified by the manufacturer.

Alternate instruments, including gas chromatographs or thermal conductivity detectors shall meet similar standards.

7.2.2 Gas Analyzer Calibration

Continuous gas analyzers shall be calibrated according to manufacturer specifications. Records of these calibrations shall be maintained.

For quarterly measurements, portable gas analyzers shall be calibrated against a gas sample with a known methane concentration prior to each use. Records of these calibrations shall be maintained according to the Project's monitoring plan and shall be conducted by appropriately trained personnel.

7.3 Electricity Production

Where an engine is serving as a destruction device, the following information shall be maintained regarding the measurement of methane combustion:

- Type, make, and model number of combustion unit(s).
- Number of combustion units that exclusively use agricultural methane gas as fuel.
- Copy of the summary table from the most recent source test (source test shall be taken within 3 years of enrollment in the CCX Offsets Program) showing the measured heat rate of combustion device(s).
- Summary tables showing kWh of electricity produced from biogas per month over the relevant period.
- Type of electrical metering device.
- Accuracy, precision, and proof of calibration of the electrical metering device per manufacturer specifications (this parameter is only required if the purchasing utility's sales meter is not used as these meters must already meet stringent requirements).

7.4 Destruction Device Operating Hours

The operating hours of each destruction device must be monitored to ensure that methane destruction is claimed for methane used only during periods when the destruction device(s) was operational. Operating hours must be continuously monitored and recorded. In general, operating hours for a flare are tracked through the use of a thermocouple which monitors the presence and temperature of the flame. Operating hours for other destruction devices such as engines should be tracked through operator logs.

Projects shall provide evidence of alarms, valves or other methods (a GCCS often incorporates one or more of these methods so that the system can be shut down when it is not functioning properly) that ensure that the destruction device does not simply vent agricultural methane gas to the atmosphere. Projects that treat agricultural methane gas and inject it into a natural gas pipeline shall only provide evidence of the quantity of gas delivered to the pipeline and are not required to provide evidence of agricultural methane gas destruction.

Exchange Offsets will not be issued for time periods where the destruction device(s) is not operating.

7.5 Destruction Device Efficiency

CCX reviewed available literature on destruction efficiency values from a variety of sources. Based on this review, CCX determined that 98% default destruction efficiency is conservative and shall be applied where Project Proponents have not conducted source tests or do not have manufacturer data. In situations where a source test has been conducted, the destruction efficiency value obtained during this source test shall be utilized rather than the default destruction efficiency value provided herein.[11]

7.6 Project-Related Emissions

Project-related emissions may result from the importation of electricity or from the use of fossil fuels. Information related to electricity usage and relevant fossil fuel consumption may be obtained from sources such as on-site electricity meters, utility invoices, and fuel purchase records. Project emissions may be omitted if the source is included in a legally binding emission reduction program for the period in question.

8. Quantifying GHG Emission Reductions

Emission reductions are assumed to be the amount of methane that would be emitted during the crediting period in the absence of the agricultural methane Project (minus Project emissions). For each year during the crediting period, Project Proponents shall compare the actual metered methane destruction values and ex-ante modeled estimates of methane destruction. Project Proponents shall claim emission reductions only for the lesser of the two values.

8.1 Calculations for Metered Methane Destruction

Tabulated records of total daily agricultural methane gas flows (in standard cubic feet per day) shall be matched with either the continuous methane content data or with the associated periodic reading to methane recovery rates, using Equation 1:

[11] Seebold et al. (2003) *Reaction Efficiency of Industrial Flares: The Perspective of the Past.*

[11]The Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories gives a standard value for the fraction of carbon oxidized for gas combustion of 99.5% (Reference Manual, Table 1.6, page 1.29). It also gives a value for emissions from processing, transmission and distribution of gas which would be a very conservative estimate for losses in the pipeline and for leakage at the end user (Reference Manual, Table 1.58, page 1.121). These emissions are given as 118,000kgCH4/PJ on the basis of gas consumption, which is 0.6%. Leakage in the residential and commercial sectors is stated to be 0 to 87,000kgCH4/PJ, which equates to 0.4%, and in industrial plants and power station the losses are 0 to 175,000kg/CH4/PJ, which is 0.8%. These leakage estimates are compounded and multiplied. The methane destruction efficiency for landfill gas injected into the natural gas transmission and distribution system can now be calculated as the product of these three efficiency factors, giving a total efficiency of (99.5% * 99.4% * 99.6%) 98.5% for residential and commercial sector users, and (99.5% * 99.4% * 99.2%) 98.1% for industrial plants and power stations.

Equation 1a: CH_4 Recovered

$$\mathbf{CH_{4recovered}} =$$

$$\mathbf{BG_{recovered} \times \%CH_4}$$

Where:

$CH_{4recovered}$	Methane recovered per day (as measured in standard ft^3/day)
$BG_{recovered}$	Biogas recovered per day (as measured in standard ft^3/day)
$\%CH_4$	Methane content of biogas

Methane flows shall be tabulated and summed on a monthly basis using the continuous daily readings for flow and the appropriate methane content readings.

Equation 1b: Alternative CH4 Recovery Method

Energy generation facilities that use agricultural methane as a fuel to generate electricity typically have detailed records of electrical generation rates in kilowatt-hours (kWhr) that can be used to calculate methane recovery. Information on the heat rate of the combustion unit in Btu per kilowatt hour (Btu/kWhr) can be used to calculate amount of methane combusted. The calculation is summarized in Equation 3:

$$\mathbf{CH_{4recovered}} =$$

$$\mathbf{(kWhr \times [Btu/kWhr]) / 1012}$$

Where:

$CH_{4recovered}$	Total CH_4 recovered (ft^3)
KWhr	Total kWhr of electricity produced from the LFG fuel
Btu/kWhr	Heat rate of electrical generator
1012	HHV of methane (as measured in Btu/ft^3) [12]

To estimate annual methane combustion rates, the Project shall use the amount of electricity generated over a one-year period in the equation above. The heat rate used in the calculation shall be from the most recent source test for the combustion device or the manufacturer specified heat rate.[13]

[12] Where the engine heat rate is specified in lower heating value, the Project Proponent shall make the appropriate adjustment.

[13] Source test, if used, shall be taken within 3 years of enrollment in the CCX Offsets program.

Equation 2: CH_4 Combusted

In order to estimate the amount of methane combusted in metric tons per year (Mg/yr), the annual methane recovery rate in cubic feet per year needs to be converted to weight using Equation 2:

$$\mathbf{CH_{4combusted}} =$$

$$\mathbf{(CH_{4recovered} \times 16.04 \times [1/10^6] * [1/24.04] \times 28.32) * DE}$$

Where:

$\mathbf{CH_{4combusted}}$	Annual methane combusted (as measured in Mg/yr)
$\mathbf{CH_{4recovered}}$	Annual methane recovered (as measured in ft^3/yr)
16.04	molecular weight of CH_4
$1/10^6$	Conversion to metric tons (Mg/g)
1/24.04	Gas constant (mol/L – measured at standard temperature and pressure – defined as 68F and 14.7psi)[14]
28.32	Conversion factor (L/cf)
DE	Destruction efficiency of the destruction device (default value of 98%)

8.2 Calculation of Project Emissions

Depending on Project-specific circumstances, certain emissions sources may need to be subtracted from total Project emission reductions using the equations below.

Equation 3a: CO_2 Emissions from Fossil Fuel Combustion

$$\mathbf{Dest_{CO2}} =$$

$$\sum_y \mathbf{(FF_y * EF_y)}$$

Where:

$\mathbf{Dest_{CO2}}$	CO_2 emissions from fossil fuel used in methane destruction process (tCO_2)
$\mathbf{FF_y}$	Total quantity of fossil fuel, y, consumed (as measured in volume of fuel)
$\mathbf{EF_y}$	Fuel specific emission factor for fuel, y (as measured in t_{CO2}/fuel quantity - values should be taken from The CCX GHG Emissions Factors online document[15])

[14] The appropriate adjustment factor should be applied if the Project flow meter(s) apply a different standard temperature and/or pressure.

[15] Relevant GHG emission factors can be found here: http://theccx.com/docs/misc/GHG_Emission_Factors.pdf

Equation 3b: CO_2 emissions from Project specific electricity consumption

$$\mathbf{Elec_{CO2} = (EL_{total} * EF_{EL})/2204.62}$$

Where:

$Elec_{CO2}$	Project specific electricity emissions (tCO_2)
EL_{total}	Total grid connected electricity consumption (as measured in MWh)
EF_{EL}	Carbon emission factor for grid electricity (taken from the most recent region specific eGrid values – measured in $lbCO_2/MWh$)
2204.62	$lbCO_2/tCO_2$

8.3 Calculation of Project Emission Reductions

Equation 4: Measured GHG Emission Reductions

$$\mathbf{ER = (CH_{4combusted} * 21) - PE}$$

Where:

ER	Total Emission Reductions (tCO_2e)
$CH_{4combusted}$	Annual methane combusted (as measured in Mg/yr)
21	Global warming potential of methane
PE	If applicable, Project emission sources should be subtracted using Equations 3a and 3b

8.4 Ex Ante Calculation for Methane Destruction Comparison

CCX requires that all Projects compare the actual metered amount of methane that is destroyed in the biogas control system with modeled methane emission reductions for each year during the crediting period. The lesser of the two values will be used for determining emission reductions.

8.4.1 Emission Factors

State-specific methane emission factors (EF(T,S,St)) for each livestock category (T) and baseline manure management system (S) included in this method are listed in Appendix B, Tables 3 and 4.

8.4.2 Solids Separation Correction Factor

For baseline liquid slurry storage or anaerobic lagoon manure management systems that separate manure solids prior to the input of liquid manure, a default solids separation correction factor (SSCF) of 0.8 must be used to calculate baseline emissions. Project specific correction factors may be used if supported by manufacturer's specifications or other acceptable data. For those systems that do not separate solids, or that utilize simple gravity separation of sand and other non-manure solids, the SSCF is equal to 1.

For Projects which did not use solids separation in the baseline case, but subsequently utilize solids separation prior to the input of liquid manure to the digester, the separated solids must be handled in a manner that ensures negligible production of methane (e.g., aerobic composting, use as animal bedding, or daily spread), otherwise, the appropriate solids separation correction factor must be used to calculate baseline emissions.

8.4.3 Ex-ante Calculation

The following procedure for ex-ante calculation of baseline methane emissions from manure digester Projects in the U.S. follows the IPCC Tier 2 approach and emission factors used in the most recent U.S. Greenhouse Gas Inventory Report. Projects located in non-Annex I countries must use country appropriate factors.

The procedure includes the following general steps for each reporting period (annual reporting is recommended to account for seasonal variability in animal populations and baseline emissions):

1. Characterize the average livestock populations included in the anaerobic digester Project for the reporting period;
2. Characterize the baseline manure management system(s) for the Project;
3. For each livestock population category and baseline manure management system, multiply the number of animals by the appropriate emission factor for that state (from Tables 3 and 4), by the appropriate solids separation correction factor, by the proportion of manure from those animals used in the digester, by the number of days in the period (Equation 5);
4. Sum the estimates for all population categories and baseline manure management systems (Equation 5);
5. Multiply the total estimate of methane emissions by the appropriate methane GWP for the reporting period and subtract metered Project emissions if appropriate (Equation 6).

Equation 5: Modeled CH_4 Emissions from Baseline Manure Management System

$$CH_{4Manure} = \sum_{T,S,} N_{(T)} * EF_{(T,S,St)} * SSCF_{(S)} * MS_{(T,S)} * P_{days}$$

Where:

$CH_{4Manure}$	Total CH_4 emissions from manure management (kg CH_4/period)
$N_{(T)}$	Number of animals in livestock species/category T included in the Project (head)
$EF_{(T,S,St)}$	Methane emission factor for livestock category T, manure management system S, and state St (kg CH_4/head/day) from Tables 3 and 4
$SSCF_{(s)}$	Solids separation correction factor for manure management system S
$MS_{(T,S)}$	Fraction of livestock category T's manure handled using manure management system S
P_{days}	number of days in the reporting period

Equation 6: Modeled GHG Emission Reductions

$$ER_{exante} = (CH_{4Manure} * 21)/1000 - PE$$

Where:

ER_{exante}	Total Emission Reductions (tCO_2e)
$CH_{4Manure}$	Total CH_4 emissions from manure management (kg CH_4/period)
21	Global warming potential of methane
1,000	Mass conversion factor (kg CO_2e/ Mg CO_2e)
PE	If applicable, Project emission sources should be subtracted using Equations 3a and 3b

9. Reporting and Recordkeeping Requirements

The Project Proponent shall implement monitoring, recordkeeping and procedures for quality management and uncertainty assessments. All relevant Project documentation shall be kept by the Aggregator for a minimum of 2 years beyond the completion of the Project.

10. VALIDATION AND VERIFICATION REQUIREMENTS

10.1 Validation

CCX Projects utilizing these guidelines are validated one of two ways. All projects must submit a PID to CCX Staff for review. Projects that adhere strictly to the requirements of this protocol are validated by CCX staff and do not require a separate Validation by the CCX Offsets Committee. For all Projects seeking to deviate from specific components of this protocol, the Project Proponent is required to complete the deviation request section of the PID for review and approval by the CCX Offsets Committee. Upon receipt and review of the deviation request, the CCX Offsets Committee will review the feasibility and appropriateness of the requested deviation(s) and, as needed, seek guidance from appropriate technical experts. Under either approach, the Project Proponents will be notified of the Project or Deviation approval by notification letter.

10.2 Verification

Prior to undertaking verification, the prospective Verifier must conduct a Project specific conflict of interest process. The prospective Verifier must complete and submit the CCX Project Specific Conflict of Interest Form[16] to CCX for approval prior to the commencement of verification activities.

Projects seeking to register Exchange Offsets shall be verified by a CCX-Approved Verifier[17] in accordance with CCX General Offsets Program Provisions, CCX Verification Guidance Document and the Project Protocols. A checklist list of verification requirements is contained in Appendix A. Independent verification is critical to ensure that the requirements of this Protocol are correctly applied. Projects shall be verified on an annual basis at minimum.

To ensure impartiality, completeness and consistency in the verification report review process an additional independent review of the submitted verification reports is conducted by the CCX Provider of Regulatory Services. Further information about the roles and responsibilities of Verifiers and the roles and responsibility of Members during verification are discussed in detail in *Chicago Climate Exchange Offset Program Verification Guidance Document* available on the CCX webpage: www.theccx.com.

[16] CCX Project Specific Conflict of Interest Form can be found in the Associated Documents section of the CCX website: www.theccx.com.
[17] A list of CCX-Approved Verifiers is found on the CCX website: www.theccx.com

APPENDIX A: VERIFICATION CHECKLIST

CCX Requirement	Assessment Criteria	Verification Findings
Validation	CCX Project Approval Letter.	
Verification: Conflicts of Interest	Complete a conflicts of interest assessment.	
Monitoring Plan	Confirm that the Project developer has a Project data monitoring plan.	
Project Definition	Confirm the Project meets the definition and/or it has been specifically approved by the CCX Offsets Committee via a deviation request approval.	
CCX Membership	Confirm that the Project Proponent is a CCX Member or Participant Member (Offset Aggregator or Provider).	
Eligibility Governing Entities with Minor Emissions	Confirm that the Project Proponent is a small emitter as defined in the Protocol. If the Project Proponent is not a small emitter they must be a CCX emitting Member.	
Ownership Status	Confirm the Project Proponent has title to the CO_2 emission reductions and, if applicable, that the Offset Aggregator has the right to market them on CCX.	
Project Start Date	Confirm the Project began on or after January 1, 2003 or that it is a Project grandfathered by CCX.	
Project Location	Confirm Project is located in the U.S. or a Kyoto Protocol non-Annex 1 country.	
Regulatory Criteria	Confirm the Project is not required by federal, state, local law or other legally binding framework.	
Common Practice Criteria	Confirm that the Project Proponent has demonstrated that the Project activity is beyond business as usual for its country of origin.	
Identification of GHG Sources Sinks and Reservoirs	Confirmation of the identification of all Sources Sinks and Reservoirs.	

Project Emissions	Confirmation of whether Project emissions have been properly included as per the Project accounting methods described in the Protocol.	
Monitoring Requirements	Confirm existence of a Project data monitoring plan with procedures for obtaining, recording, compiling and analyzing data and required information	
Flow Monitoring	Confirmation of continuous flow monitoring requiring measurement and recording, at least, every 15 minutes.	
	Confirmation the flow meter is installed in a location which allows for laminar flow or appropriate technology and professional engineering assessment of meter accuracy.	
Flow Meter Performance Standard	Confirmation of manufacturer's specification that the flow meter accuracy is +/- 5% of reading.	
	Proof of initial calibration	
	Confirmation of capability to record flow, at least, every 15 minutes.	
	Confirm the flow meter has a means to correct for temperature and pressure, where applicable.	
Flow Meter Calibration	Confirm annual (or more frequent) flow meter calibration unless otherwise specified by the manufacturer.	
	Confirm calibration performed and documented to be in accordance with manufacturers specifications and methodologies.	
	Confirm that the calibration and was performed by the manufacturer, an ISO 17025 certified entity, or other appropriately trained personnel.	
	Confirm records of calibration and calibration methodologies are documented and reviewed.	

Flow Meter Location	Confirm location provides for proper laminar flow or has been approved by professional engineer.	
Methane Content Analysis	Confirm frequency of methane fraction recording to be continuous or, at least, quarterly.	
	Confirm device or approach used to determine methane fraction is conducted with a portable gas analyzer or by laboratory analysis of sampled gas.	
Gas Analyzer Performance Standard	Confirm the precision of the recordings to be to the nearest 0.1 percent.	
	Confirm measurement device is specified by the manufacturer to provide results that are +/- 10% of the actual reading.	
	Confirm alternative approach to determining methane quality meets the requirements that readings are +/- 10% of the actual reading.	
Gas Analyzer Calibration	Confirm calibration has been performed in accordance with the manufacturers' specification.	
Electricity Production	If applicable, confirm the items provided in the cells below:	
	Type, make and model number of the engine	
	Copy of most recent source test or manufacturer specified heat rate	
	Monthly electricity production records	
	Type of electrical metering device	
	Proof that calibration of metering device is in accordance with the manufacturers specification, if applicable	
Destruction Device Operating Hours	Confirmation of continuous monitoring of operating hours of the destruction device; for destruction devices that utilize the alternative CH4 recovery method, records of electrical generation rates (in kWhr) are sufficient	

	Confirmation of existence of alarms, valves or other methods to ensure against venting to atmosphere.	
Destruction Device Efficiency	Confirmation of the use of the default value or the value specified by the manufacturer, if lower.	
Project Related Emissions	Confirmation of monitoring of Project related emissions.	
Calculation of Metered Methane Destruction	Confirmation of tabulated daily gas flows in scf/day.	
	Confirmation of, at least, quarterly methane content readings.	
	Confirmation of monthly methane flows by combining gas flows and methane content	
	Confirmation of alternative calculation of methane destruction, if applicable	
Calculation of Project Emissions	Confirmation of Project emissions calculations.	
Calculation of Project Emission Reductions	Confirmation of Project emission reduction calculations.	
Ex Ante Calculation of Methane Destruction Comparison	Confirmation that ex ante calculations for methane destruction including emission factors, solid separation correction factor and ex ante calculation formulas were properly applied and conducted.	
Reporting and Record Keeping Requirements	Confirmation of procedures to retain relevant Project records for, at least, 2 years beyond the verification date.	

APPENDIX B: EMISSION FACTORS

The emission factors used in Equation 5 (above) are derived using typical animal mass (TAM) and maximum methane generation potential (Bo) data from Appendix C, Table 5, and using state-specific data for volatile solids production rates (VS) and methane conversion factors (MCF) for the different baseline manure management systems from Appendix B, Tables 6 and 7.

The below equation is provided for illustrative purposes only and demonstrates how CCX has calculated the emission factors found in Tables 3 and 4.

Equation 7: Emission Factor for Specific Baseline Scenario

$$\mathbf{EF_{(T,S,St)} = TAM_{(T)} * (VS_{(T,St)}/1000) * B_{o(T)} * 0.67 * (MCF_{(S,\ St)}/100)}$$

Where:

$\mathbf{EF_{(T,S,St)}}$	CH_4 emission factor for livestock category T, manure management system S and State St (kg CH_4/head/day), from Tables 3 and 4.
$\mathbf{TAM_{(T)}}$	Typical animal mass for livestock species/category T (kg/head)
$\mathbf{VS_{(T,St)}}$	Volatile solids production rate for each livestock category and state (kg VS/day/1000 kg animal mass)
$\mathbf{B_{o(T)}}$	Maximum CH_4 generation potential for livestock category T (m^3 CH_4/kg VS)
$\mathbf{MCF_{(S,St)}}$	Methane conversion factor for baseline manure management system S, and state St (%)
0.67	CH_4 volume to mass conversion factor (kg CH_4/ m^3 CH_4)
1,000	VS conversion factor (kg animal mass/1000 kg animal mass)
100	MCF percentage conversion factor

Table 3 – Methane Emission Factors (EF(T,S,St)) for Liquid/Slurry & Pit Storage Baseline Manure Management Systems (S) by Livestock Category (T) and State (St); (kg CH_4 /head/day) [18]

State	Dairy Cow	Dairy Heifer	Feedlot Steers	Feedlot Heifers	Market Swine <60 lbs.	Market Swine 60-119 lbs.	Market Swine 120-179 lbs.	Market Swine >180 lbs.	Breeding Swine
Alabama	0.327	0.169	0.138	0.125	0.019	0.030	0.050	0.066	0.070
Alaska	0.119	0.060	0.049	0.045	0.006	0.010	0.017	0.022	0.023
Arizona	0.635	0.249	0.200	0.181	0.018	0.028	0.046	0.062	0.065
Arkansas	0.262	0.169	0.137	0.123	0.018	0.028	0.046	0.062	0.065
California	0.305	0.141	0.113	0.102	0.014	0.023	0.038	0.051	0.053
Colorado	0.195	0.089	0.071	0.064	0.011	0.017	0.028	0.038	0.040
Connecticut	0.200	0.091	0.078	0.071	0.011	0.017	0.028	0.038	0.040
Delaware	0.236	0.116	0.100	0.091	0.014	0.023	0.038	0.051	0.053
Florida	0.441	0.217	0.168	0.153	0.024	0.038	0.063	0.084	0.088
Georgia	0.350	0.165	0.129	0.118	0.019	0.029	0.048	0.065	0.068
Hawaii	0.431	0.237	0.188	0.171	0.027	0.042	0.070	0.093	0.098
Idaho	0.251	0.101	0.081	0.074	0.010	0.016	0.027	0.036	0.038
Illinois	0.251	0.129	0.103	0.093	0.014	0.021	0.035	0.047	0.050
Indiana	0.239	0.117	0.095	0.086	0.013	0.021	0.034	0.046	0.048
Iowa	0.221	0.109	0.088	0.080	0.012	0.019	0.031	0.041	0.043
Kansas	0.268	0.133	0.106	0.096	0.014	0.023	0.038	0.051	0.053
Kentucky	0.262	0.141	0.108	0.098	0.016	0.025	0.041	0.055	0.058
Louisiana	0.314	0.209	0.151	0.137	0.022	0.034	0.057	0.076	0.079
Maine	0.153	0.073	0.069	0.062	0.009	0.014	0.022	0.030	0.031
Maryland	0.239	0.113	0.104	0.094	0.014	0.022	0.037	0.049	0.051
Massachusetts	0.179	0.087	0.075	0.068	0.010	0.016	0.027	0.036	0.038
Michigan	0.220	0.101	0.082	0.074	0.011	0.018	0.030	0.040	0.041
Minnesota	0.197	0.101	0.081	0.073	0.011	0.017	0.028	0.038	0.040
Mississippi	0.346	0.177	0.140	0.127	0.019	0.031	0.051	0.068	0.071
Missouri	0.238	0.137	0.109	0.099	0.015	0.023	0.039	0.052	0.055
Montana	0.164	0.084	0.068	0.061	0.009	0.014	0.024	0.032	0.033
Nebraska	0.225	0.117	0.093	0.085	0.013	0.020	0.033	0.044	0.046
Nevada	0.256	0.109	0.087	0.079	0.013	0.020	0.033	0.044	0.046
New Hampshire	0.175	0.076	0.068	0.062	0.010	0.015	0.025	0.033	0.035
New Jersey	0.215	0.105	0.098	0.088	0.013	0.020	0.033	0.044	0.046
New Mexico	0.292	0.121	0.098	0.089	0.013	0.020	0.033	0.044	0.046
New York	0.184	0.084	0.073	0.066	0.010	0.016	0.026	0.035	0.036
North Carolina	0.300	0.137	0.110	0.099	0.018	0.028	0.046	0.062	0.065
North Dakota	0.163	0.093	0.074	0.067	0.010	0.015	0.025	0.033	0.035
Ohio	0.216	0.113	0.090	0.082	0.012	0.019	0.032	0.043	0.045
Oklahoma	0.305	0.174	0.127	0.115	0.016	0.025	0.041	0.055	0.058
Oregon	0.194	0.084	0.065	0.059	0.009	0.014	0.024	0.032	0.033
Pennsylvania	0.209	0.094	0.084	0.076	0.012	0.019	0.032	0.043	0.045
Rhode Island	0.191	0.094	0.087	0.079	0.011	0.018	0.030	0.040	0.041
South Carolina	0.348	0.165	0.129	0.118	0.019	0.030	0.050	0.066	0.070
South Dakota	0.208	0.105	0.083	0.076	0.011	0.018	0.030	0.040	0.041
Tennessee	0.279	0.141	0.116	0.105	0.018	0.028	0.046	0.062	0.065
Texas	0.384	0.192	0.139	0.126	0.019	0.029	0.048	0.065	0.068
Utah	0.237	0.101	0.081	0.073	0.010	0.016	0.027	0.036	0.038
Vermont	0.162	0.076	0.068	0.062	0.009	0.014	0.024	0.032	0.033
Virginia	0.252	0.121	0.096	0.087	0.014	0.023	0.038	0.051	0.053
Washington	0.215	0.084	0.066	0.060	0.010	0.015	0.025	0.033	0.035
West Virginia	0.198	0.102	0.089	0.081	0.012	0.019	0.032	0.043	0.045
Wisconsin	0.192	0.097	0.077	0.070	0.011	0.017	0.028	0.038	0.040
Wyoming	0.158	0.080	0.063	0.058	0.010	0.016	0.026	0.035	0.036

[18] Data from EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007

Table 4 – Methane Emission Factors (EF(T,S,St)) for Anaerobic Lagoon Baseline Manure Management Systems (S) by Livestock Category (T) and State (St); (kg CH_4/ head/day) [19]

State	Dairy Cow	Dairy Heifer	Feedlot Steers	Feedlot Heifers	Market Swine <60 lbs.	Market Swine 60-119 lbs.	Market Swine 120-179 lbs.	Market Swine >180 lbs.	Breeding Swine
Alabama	0.592	0.306	0.251	0.227	0.035	0.056	0.092	0.123	0.129
Alaska	0.397	0.201	0.164	0.149	0.023	0.036	0.059	0.079	0.083
Arizona	0.820	0.322	0.259	0.234	0.034	0.054	0.090	0.120	0.126
Arkansas	0.525	0.339	0.274	0.246	0.035	0.055	0.091	0.122	0.127
California	0.645	0.298	0.239	0.216	0.033	0.052	0.086	0.115	0.121
Colorado	0.584	0.266	0.213	0.193	0.032	0.050	0.083	0.111	0.116
Connecticut	0.551	0.251	0.217	0.197	0.031	0.049	0.081	0.109	0.114
Delaware	0.546	0.269	0.230	0.210	0.034	0.053	0.087	0.117	0.123
Florida	0.645	0.318	0.246	0.224	0.036	0.056	0.093	0.125	0.131
Georgia	0.658	0.310	0.243	0.221	0.035	0.055	0.091	0.122	0.127
Hawaii	0.562	0.310	0.246	0.223	0.035	0.055	0.091	0.122	0.127
Idaho	0.693	0.278	0.225	0.204	0.031	0.048	0.080	0.107	0.113
Illinois	0.581	0.298	0.237	0.215	0.034	0.053	0.087	0.117	0.123
Indiana	0.602	0.294	0.238	0.216	0.033	0.052	0.086	0.115	0.121
Iowa	0.581	0.286	0.231	0.210	0.032	0.051	0.084	0.112	0.118
Kansas	0.608	0.302	0.241	0.219	0.034	0.053	0.089	0.119	0.124
Kentucky	0.568	0.306	0.235	0.214	0.034	0.054	0.090	0.120	0.126
Louisiana	0.528	0.352	0.255	0.230	0.036	0.056	0.093	0.125	0.131
Maine	0.475	0.225	0.212	0.191	0.028	0.044	0.073	0.098	0.103
Maryland	0.563	0.265	0.244	0.220	0.034	0.053	0.087	0.117	0.123
Massachusetts	0.500	0.243	0.210	0.191	0.031	0.048	0.080	0.107	0.113
Michigan	0.606	0.278	0.226	0.205	0.032	0.050	0.083	0.111	0.116
Minnesota	0.537	0.274	0.220	0.200	0.031	0.049	0.081	0.109	0.114
Mississippi	0.613	0.314	0.248	0.225	0.035	0.056	0.092	0.123	0.129
Missouri	0.525	0.302	0.240	0.217	0.034	0.053	0.089	0.119	0.124
Montana	0.493	0.253	0.204	0.184	0.029	0.046	0.077	0.103	0.108
Nebraska	0.558	0.290	0.231	0.210	0.033	0.051	0.085	0.114	0.119
Nevada	0.672	0.286	0.229	0.208	0.033	0.051	0.085	0.114	0.119
New Hampshire	0.533	0.232	0.207	0.188	0.030	0.047	0.078	0.104	0.109
New Jersey	0.534	0.262	0.243	0.219	0.033	0.051	0.085	0.114	0.119
New Mexico	0.711	0.294	0.238	0.216	0.033	0.051	0.085	0.114	0.119
New York	0.528	0.240	0.210	0.190	0.030	0.048	0.079	0.106	0.111
North Carolina	0.661	0.302	0.242	0.219	0.035	0.055	0.091	0.122	0.127
North Dakota	0.467	0.266	0.213	0.193	0.030	0.047	0.078	0.104	0.109
Ohio	0.548	0.286	0.228	0.207	0.033	0.051	0.085	0.114	0.119
Oklahoma	0.601	0.343	0.251	0.227	0.034	0.054	0.090	0.120	0.126
Oregon	0.581	0.253	0.194	0.177	0.029	0.045	0.074	0.100	0.104
Pennsylvania	0.562	0.254	0.226	0.205	0.032	0.051	0.084	0.112	0.118
Rhode Island	0.514	0.254	0.235	0.212	0.032	0.050	0.083	0.111	0.116
South Carolina	0.661	0.314	0.246	0.224	0.035	0.056	0.092	0.123	0.129
South Dakota	0.560	0.282	0.224	0.203	0.032	0.050	0.083	0.111	0.116
Tennessee	0.606	0.306	0.251	0.227	0.035	0.055	0.091	0.122	0.127
Texas	0.696	0.348	0.253	0.229	0.035	0.055	0.091	0.122	0.127
Utah	0.653	0.278	0.223	0.202	0.031	0.048	0.080	0.107	0.113
Vermont	0.486	0.229	0.204	0.185	0.029	0.045	0.074	0.100	0.104
Virginia	0.613	0.294	0.233	0.212	0.034	0.053	0.087	0.117	0.123
Washington	0.645	0.253	0.198	0.180	0.029	0.046	0.077	0.103	0.108
West Virginia	0.510	0.262	0.229	0.207	0.033	0.051	0.085	0.114	0.119
Wisconsin	0.545	0.274	0.218	0.198	0.031	0.049	0.081	0.109	0.114
Wyoming	0.497	0.253	0.199	0.181	0.030	0.048	0.079	0.106	0.111

[19] Data from EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007

APPENDIX C: EMISSION FACTOR VARIABLES

Livestock categories (T) included in this method are listed in Table 5. For market swine (finishing operations), the use of a population-wide average animal weight is an acceptable conservative alternative.

Table 5 – Livestock Categories and Waste Characteristics Included in Baseline Methane Emission Calculations and Emission Factor Derivation[20]

Livestock Category, T	Average TAM[1]	Total Kjeldhal N Excretion Rates, Nex	Maximum Methane Generation Potential, Bo	Volatile Solids, VS
Units	*(kg)*	*(kg/day per 1,000 kg mass)*	*(m3 CH4/kg VS)*	*(kg/day per 1,000 kg mass)*
Dairy Cattle				
Dairy Cows	604	0.44	0.24	(from Table 6)
Dairy Heifer	476	0.31	0.17	(from Table 6)
Beef Cattle				
Feedlot Steers	420	0.30	0.33	(from Table 6)
Feedlot Heifers	420	0.30	0.33	(from Table 6)
Swine				
Market < 60 lbs	16	0.60	0.48	8.8
Market 60-119 lbs	41	0.42	0.48	5.4
Market 120-179 lbs	68	0.42	0.48	5.4
Market >180 lbs	91	0.42	0.48	5.4
Breeding	198	0.24	0.48	2.6
[1] Typical Animal Mass				

[20] Data from EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007, Annex 3.10

Table 6 – Volatile Solids Production Rates (VS(T,St)) by Livestock Category (T) and State (St)[21] Used for Derivation of Methane Emission Factors (EF(T,S,St)); (kg VS/day/1,000 kg animal mass)

State	Dairy Cow	Dairy Heifer	Feedlot Steers	Feedlot Heifers
Alabama	8.02	7.42	3.21	3.55
Alaska	8.18	7.42	3.20	3.53
Arizona	10.55	7.42	3.15	3.48
Arkansas	7.11	8.22	3.48	3.88
California	8.98	7.42	3.15	3.48
Colorado	9.11	7.42	3.15	3.47
Connecticut	8.22	6.70	3.07	3.38
Delaware	7.60	6.70	3.05	3.35
Florida	8.40	7.42	3.06	3.36
Georgia	8.80	7.42	3.09	3.40
Hawaii	7.52	7.42	3.12	3.44
Idaho	10.34	7.42	3.18	3.51
Illinois	8.08	7.42	3.13	3.45
Indiana	8.49	7.42	3.18	3.51
Iowa	8.43	7.42	3.18	3.51
Kansas	8.35	7.42	3.14	3.46
Kentucky	7.70	7.42	3.03	3.33
Louisiana	6.88	8.22	3.14	3.47
Maine	7.88	6.70	3.32	3.69
Maryland	7.94	6.70	3.25	3.60
Massachusetts	7.69	6.70	3.07	3.38
Michigan	9.05	7.42	3.20	3.53
Minnesota	8.13	7.42	3.16	3.49
Mississippi	8.09	7.42	3.10	3.42
Missouri	7.21	7.42	3.12	3.44
Montana	8.05	7.42	3.15	3.48
Nebraska	7.98	7.42	3.14	3.46
Nevada	9.75	7.42	3.15	3.48
New Hampshire	8.58	6.70	3.16	3.48
New Jersey	7.64	6.70	3.28	3.64
New Mexico	10.03	7.42	3.18	3.51
New York	8.24	6.70	3.10	3.42
North Carolina	9.07	7.42	3.15	3.48
North Dakota	7.29	7.42	3.15	3.48
Ohio	7.94	7.42	3.14	3.46
Oklahoma	8.04	8.22	3.18	3.51
Oregon	9.49	7.42	3.02	3.31
Pennsylvania	8.27	6.70	3.15	3.48
Rhode Island	7.56	6.70	3.26	3.61
South Carolina	8.73	7.42	3.09	3.40
South Dakota	8.24	7.42	3.13	3.45
Tennessee	8.21	7.42	3.22	3.56
Texas	9.19	8.22	3.16	3.49
Utah	9.75	7.42	3.15	3.48
Vermont	7.95	6.70	3.16	3.48
Virginia	8.64	7.42	3.12	3.44
Washington	10.54	7.42	3.07	3.38
West Virginia	7.29	6.70	3.10	3.42
Wisconsin	8.25	7.42	3.13	3.45
Wyoming	8.13	7.42	3.10	3.41

[21] Data from EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007, Annex 3, Table A-171

Table 7 – Methane Conversion Factors ($MCF_{(S,St)}$) by Baseline Manure Management System (S) and State (St)[22] Used for Derivation of Methane Emission Factors ($EF_{(T,S,St)}$); (percent)

	Dairy		Swine		Beef
State	Liquid / Slurry & Pit Storage	Anaerobic Lagoon	Liquid / Slurry & Pit Storage	Anaerobic Lagoon	Liquid / Slurry
Alabama	42	76	42	78	43
Alaska	15	50	14	50	15
Arizona	62	80	39	76	50
Arkansas	38	76	39	77	38
California	35	74	32	73	41
Colorado	22	66	24	70	24
Connecticut	25	69	24	69	26
Delaware	32	74	32	74	33
Florida	54	79	53	79	54
Georgia	41	77	41	77	40
Hawaii	59	77	59	77	59
Idaho	25	69	23	68	23
Illinois	32	74	30	74	30
Indiana	29	73	29	73	30
Iowa	27	71	26	71	28
Kansas	33	75	32	75	33
Kentucky	35	76	35	76	35
Louisiana	47	79	48	79	48
Maine	20	62	19	62	20
Maryland	31	73	31	74	31
Massachusetts	24	67	23	68	24
Michigan	25	69	25	70	25
Minnesota	25	68	24	69	25
Mississippi	44	78	43	78	43
Missouri	34	75	33	75	34
Montana	21	63	20	65	23
Nebraska	29	72	28	72	28
Nevada	27	71	28	72	28
New Hampshire	21	64	21	66	21
New Jersey	29	72	28	72	29
New Mexico	30	73	28	72	30
New York	23	66	22	67	23
North Carolina	34	75	39	77	35
North Dakota	23	66	21	66	23
Ohio	28	71	27	72	28
Oklahoma	39	77	35	76	36
Oregon	21	63	20	63	24
Pennsylvania	26	70	27	71	27
Rhode Island	26	70	25	70	26
South Carolina	41	78	42	78	41
South Dakota	26	70	25	70	26
Tennessee	35	76	39	77	37
Texas	43	78	41	77	36
Utah	25	69	23	68	25
Vermont	21	63	20	63	21
Virginia	30	73	32	74	31
Washington	21	63	21	65	23
West Virginia	28	72	27	72	28
Wisconsin	24	68	24	69	25
Wyoming	20	63	22	67	24

[22] Data from EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007, Annex 3, Table A-175