CAPCOA GHG Rx Protocol:

Biomass Waste for Energy Project Reporting Protocol

(Based on Biomass to Energy protocol Version 6.3 approved by Placer County Air Pollution Control District on January 2013)

(Approved by the CAPCOA Board 2013)

Biomass Waste for Energy Project Reporting Protocol

GHG Emission Reduction Accounting

Version 6.3

January 2013

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1.0 Introduction

This protocol provides accounting, reporting, and monitoring procedures to determine greenhouse gas (GHG) reductions associated with biomass waste for energy projects.

The protocol is for projects which process and transport biomass waste for the generation of energy (e.g. electricity and process heat). The protocol is limited to projects where, under baseline, business as usual conditions, at the start of the project, the biomass waste would have otherwise been legally disposed of through: (1) open burning; (2) decay and decomposition in the field; or (3) landfill. The protocol is also limited to biomass waste that is the result of sustainable harvesting operations; and includes urban woody post-consumer yard wastes.

Biomass waste for energy projects reduce GHG emissions through: (1) avoiding methane (CH_4) and nitrous oxide (N_2O) emissions that occur during disposal through open burning, decay and decomposition, and/or landfilling; and (2) producing renewable energy that displaces GHG emissions from fossil fuel combustion needed for an equivalent energy supply.

2.0 Project

Biomass waste is generated from forestry, agriculture, urban landscape, and related industries. Biomass is defined as non-fossilized and biodegradable organic material originating from plant material. Biomass waste disposal methods include open burning, decay and decomposition in the field, or landfill. Biomass waste includes:

- Forest slash (non-merchantable) remains from forest management activities including timber harvesting or forest thinning and fuel hazard reduction. These include small trees, brush, tree tops, and branches.
- Defensible space clearing residues (brush, tree branches and trunks, clippings).
- Orchard and vineyard removals and prunings.
- Field straws and stalks.
- Urban prunings/cuttings residues.

Biomass waste has energy content that can be utilized in energy recovery facilities, which include:

- Direct biomass combustion, producing heat and/or electricity.

- Biomass gasification, producing syngas used for heat or electricity production, or conversion into alternative transportation fuels (e.g. biofuels).

Sources of GHG emissions from a biomass waste for energy project are shown in Table 1.

2.1 Project Definition

For this protocol, the GHG reduction project involves the use of biomass wastes for energy recovery, where otherwise under baseline, business as usual conditions, the biomass waste would have been disposed of through open burning, left to decay and decompose in the field, or landfilled.

The project developer must provide information defining the project operations, including:

- Location where the biomass waste is generated.
- Operation for which the biomass waste is a byproduct, i.e. how is the biomass waste generated.
- Generation (rate and timing) of the biomass waste.
- Composition of the biomass waste.
- Historical, current, and anticipated future, disposal practice for the biomass waste in the absence of the proposed biomass waste to energy project.
- Biomass waste processing operations prior to transport, such as conveyors, grinders, and loaders.
- Biomass waste transportation method.
- Location of energy recovery facility.

- Type of energy produced (e.g. electricity, heat, fuels).
- Estimated cost of processing and transporting biomass waste to the energy recovery facility.
- Generation rate of energy from biomass waste.
- User(s) / purchaser(s) of energy generated from biomass waste.
- Permitting status of the energy recovery facility.
- Documentation of environmental assessments required as part of the biomass waste generating activities. These might include the National Environmental Policy Act (NEPA), California Environmental Quality Act (CEQA), California Forest Practices Rules and Regulations, Timber Harvest Plans, and Best Management Practices assessments.

This information must be provided in Form A, included as an attachment to the protocol. Form A must be completed, submitted, and approved prior to project commencement.

2.2 Project Developer

Project developers can include biomass generators, biomass waste energy recovery operators, and/or third party aggregators. Ownership of the GHG reductions must be established by clear and explicit title, where ownership is determined through agreement between project developers. This is important to avoid double counting of reductions by the energy recovery operator, biomass processor, biomass owner (landowner), or third party investor.

2.3 Methane and Nitrous Oxide Global Warming Potential Characterization Factors

Methane (CH_4) has a global warming potential characterization factor of 21 tons of CO_{2e} per ton of methane.

Nitrous oxide (N_2O) has a global warming potential characterization factor of 310 tons CO_{2e} per ton N_2O.

3.0 Eligibility

Projects must meet the following requirements to be eligible for GHG offset credits under this protocol.

3.1 Biomass from Qualified Operations

The biomass waste material used for energy recovery must be characterized as:

- "Biomass" – The material must be non-fossilized and biodegradable organic material.

- "Excess waste" – The material must be an excess waste byproduct that, in the absence of the project, would be disposed of through open burning, or deposited in the field or landfilled.

- "Sustainable" – The material must be a byproduct of operations which:

  -- Protect or enhance long-term productivity of the site by maintaining or improving soil productivity, water quality, wildlife habitat, and biodiversity.

  -- Meet all local, state, and federal environmental regulations, including National Environmental Policy Act (NEPA), California Environmental Quality Act (CEQA), California Forest Practices Rules and Regulations, Timber Harvest Plans, and Best Management Practices.

3.2 Additionality

Project GHG emission reductions must be "additional" to what would have otherwise occurred.

It must be demonstrated that the existing, baseline business as usual disposal practice of the biomass wastes at the beginning date of the project is through either:

- Open burning in the vicinity of the production site. It must be demonstrated that this disposal practice is a legally allowable method under the local Air District and the State and that an open pile burn permit has been or could be obtained.

- Decay and decomposition in the vicinity of the production site, with no commercial value derived from the end-product.

- Landfilled.

The project developer must demonstrate there are no alternative uses for the biomass waste. It must not be currently economical within the local market to utilize or sell the biomass waste as a product or process feedstock. This requires providing documentation of previous historical disposal practices, current disposal practices in the absence of the proposed project, and future planned/anticipated disposal practices.

3.3 Energy Recovery

The biomass waste must be used in an energy recovery facility. The energy recovery facility must:

- Meet all Federal, State, and local environmental regulations, including (but not limited to) air quality, water discharge, and solid waste.
- Produce energy (e.g. electricity, heat, fuel) that is under control of a project participant, or an entity that has a contractual agreement or is an affiliate with the project developer.
- Produce energy that is valuable and utilized, and would not have otherwise been generated.

3.4 Energy Sales

Energy produced from the biomass wastes must be documented to not be claimed for use by other projects for GHG mitigation purposes.

3.5 Location

This protocol is applicable to biomass generation and energy recovery project operations that are located in California.

3.6 Project Start Date

Projects are eligible which begin after the date of approval of the protocol (January 2013), or after January 1, 2007 for qualifying early action projects, and after the necessary project initiation forms have been completed and approved (including Form A).

4.0 Assessment Boundary

The biomass waste for energy project boundary is defined to include all GHG emissions from operations that are the result of the biomass waste for energy project. The physical boundary of the biomass waste for energy project is shown in Figure 1. GHG emissions must be accounted for operations, as detailed in Table 1, including:

Baseline, Business as Usual

- Open biomass burning. Includes quantification of CO_2, CH_4, and N_2O.
- Decay and decomposition of biomass disposal in field. Includes quantification of CH_4 and N_2O.
- Landfill. Includes quantification of CH_4.

Biomass Waste for Energy Project

- Fossil fuel fired engines, at the site where the biomass waste is generated, that would not have been used had the biomass waste been disposed of through open burning or left to decay. This includes engines that power biomass waste processing equipment used at the site of biomass waste generation – including chippers, grinders, shredders, loaders, excavators, conveyors, etc. Includes quantification of CO_2.
- Fossil fuel fired engines used to facilitate transport of biomass waste from the site of generation to the energy recovery facility. Includes quantification of CO_2.
- Biomass waste usage at the energy recovery facility. For biomass combustion boilers, quantification of CO_2 is required. The quantification of CH_4 and N_2O is not required as it is considered negligible for a combustor that meets state and local air quality regulations. Other types of energy recovery units may require quantification of CH_4 and N_2O.
- Fossil fuel fired engines used for transportation of equipment and personal to the biomass waste processing site. Includes quantification of CO_2 emissions.
- Fossil fuel fired engines used at energy recovery facility for operation of auxiliary equipment, such as conveyors and loaders, that would not have been used otherwise in the absence of the project. Includes quantification of CO_2 emissions.

5.0 Calculation Methods

5.1 Biomass Waste for Energy Project

5.1.1 Biomass Processing Rate

Determine the quantity of biomass (total wet weight), BM_W , meeting the above eligibility criteria, which is delivered to the energy recovery facility:

$BM_{T, W}$ Quantity of wet (green) biomass utilized at energy recovery facility (wet tons). Determined from the summation of direct weight measurement of every separate biomass delivery received at the energy recovery facility.

Determine the quantity of biomass (total bone dry weight), $BM_{T, D}$, as.

$$BM_{T, D} = BM_{T, W} * (1 - M) \qquad \text{(Eq. 1)}$$

where:

M Moisture content of biomass (%). Determined through sampling and analysis of the biomass delivered to the energy recovery facility. (Sampling and measurement will be based on ASTM E870-82, ASTM D 3173, or equivalent. Sampling will occur at biomass energy recovery facility.)

5.1.2 Energy Produced from Biomass

Determine the energy content of biomass waste delivered to the biomass energy recovery facility, Q_{BM}, (MMBtu) as:

$$Q_{BM} = BM_{T, D} * HHV_{BM} \qquad \text{(Eq. 2)}$$

where:

HHV_{BM} Higher Heating Value of biomass waste (MMBtu/dry ton). Determined by periodic or most current sampling and analysis of biomass. (Measurement of HHV will be based on ASTM E870-82, ASTM D 5865, or equivalent.). HHV is utilized within this protocol instead of LHV because it is more prominently used in the biomass energy recovery industry. If LHV is utilized, appropriate conversion factors must be used to calculate an equivalent HHV.

Next, determine the energy produced from the biomass at the energy recovery facility, E_{BM}, as:

$$E_{BM} = Q_{BM} * f \qquad \text{(Eq. 3)}$$

where:

f Energy production generation efficiency. Determined as the ratio of net useful energy produced by the facility (gross energy produced minus parasitic plant energy requirements) to the total fuel heat input rate. This parameter must be determined on a basis of HHV.

For the production of electricity, this is referred to as the facility heat rate (determined as the kWh_e new electricity / MMBtu fuel input).

The efficiency will be based on measurements of facility operations using the biomass waste based on an annual facility average efficiency.

5.1.3 GHG Displaced by Energy Produced from Biomass

Determine the GHG emissions from fossil fuel combustion that are displaced by the energy produced from the biomass, GHG_E, as:

$$GHG_E = E_{BM} * EF_E \qquad \text{(Eq. 4)}$$

where:

EF_E Emission factor for CO_{2e} from energy generation that is displaced by the biomass for energy project (tons CO_{2e} / unit of energy supplied by the excess biomass for energy facility).

For displaced electricity, it might be appropriate to the use of a factor of 800 lb CO_{2e} / MW – based on marginal electricity generation supplied by a combined cycle natural gas system.

Alternatively, it may be appropriate to utilize the local serving utility CO_2 emission factor, determined as the average of all baseload and marginal production sources. Particularly, in cases where the utility overall average is lower than that of combined cycle natural gas generation system.

5.1.4 GHG Emissions from Ancillary Biomass Handling, Processing, and Transportation Operations

Determine the amount of GHG resulting from ancillary biomass handling, processing, and transport operations, GHG_{AUX} , as:

$$GHG_{AUX} = GHG_{TRANS} + GHG_{PROC} \qquad \text{(Eq. 5)}$$

where:

$GHG_{TRANS} = VM * MPG * EF_{FF}$ (Eq. 6)

GHG_{TRANS} CO_{2e} emissions from vehicles used to transport biomass to the energy recovery facility; and vehicles used to transport workers to the biomass processing site.

VM Vehicle miles driven for biomass transport (round trip); and miles driven to transport workers to the biomass processing site. In reporting period.

MPG Vehicle mileage achieved by transport vehicles (miles/gallon).

EF_{FF} Emission factor for CO_2 for fossil fuel combustion (lb CO_2 / gal fuel) -- for diesel, 22.23 lb CO_2/gallon; for gasoline, 19.37 lb CO_2/gal.

and

$GHG_{PROC} = (T_{FF} * R_{FF}) * EF_{FF}$ (Eq. 7)

where:

T_{FF} Time equipment used to operate biomass processing equipment, including grinders, chippers, shredders, conveyors, and loaders, bulldozers, and excavators. (Reported in hours).

R_{FF} Average volumetric fuel use rate (gallons per hour) for equipment used to operate biomass processing equipment, including grinders, chippers, shredders, conveyors, and loaders, bulldozers, and excavators. (Reported in hours).

5.1.5 *GHG Emissions From Biomass Combustion*

Determine CO_2 from biomass combustion, as:

$GHG_{BCOM} = BM_{T, D} * EF_{CO2\ BM}$

where:

$EF_{CO2\ BM}$ Emission factor for CO_2 from biomass combustion, recommended as 1.8 tons CO_2 / ton dry biomass.

5.1.6 *GHG Emissions From Biomass for Energy Project*

Determine the biomass for energy project GHG emissions, GHG_{PROJ}, as:

$$GHG_{PROJ} = GHG_{AUX} - GHG_{E} + GHG_{BCOM} \quad \text{(Eq. 8)}$$

5.2 Baseline

5.2.1 Baseline Biomass Disposal Practice

Determine the quantity (dry tons) of biomass that would have been uncontrolled open burned, $BM_{OB, D}$, the quantity of biomass that would have been left to decay in the field, $BM_{DD, D}$, and the quantity of biomass that would have been landfilled, $BM_{LF, D}$:

$$BM_{OB, D} = BM_{T, D} * X_{OB} \quad \text{(Eq. 9)}$$

$$BM_{DD, D} = BM_{T, D} * X_{DD} \quad \text{(Eq. 10)}$$

$$BM_{LF, D} = BM_{T, D} * X_{LF} \quad \text{(Eq. 11)}$$

where:

X_{OB} Fraction (dry weight %) of biomass that would have been uncontrolled open burned. Based on historical, current, and future projected practices.

X_{DD} Fraction (dry weight %) of biomass that would have been left to decay in the field. Based on historical, current, and future projected practices.

X_{LF} Fraction (dry weight %) of biomass that would have been landfilled.

5.2.2 GHG Emissions from Baseline Disposal

Determine GHG emissions that would have resulted from the baseline disposal practices, GHG_{BASE}, as the sum of emissions from uncontrolled open burning, GHG_{OB}, field decay and decomposition, GHG_{DD}, and landfilled, GHG_{LF}, as:

$$GHG_{BASE} = GHG_{OB} + GHG_{DD} + GHG_{OB} \quad \text{(Eq. 12)}$$

where:

GHG_{BASE} Total baseline greenhouse gas emissions, as CO_2 equivalent (tons CO_{2e})

GHG_{OB} Greenhouse gas emissions from uncontrolled open burning, as CO_2 equivalent (tons CO_{2e})

GHG_{DD} Greenhouse gas emissions from field decay and decomposition, as CO_2 equivalent (tons CO_{2e})

GHG_{LF} Greenhouse gas emissions from landfilling, as CO_2 equivalent (tons CO_{2e})

and,

$$GHG_{OB} = (EF_{OB, CO2} * BM_{OB, D} * BF) + (EF_{OB, CH4} * BM_{OB, D} * BF * 21) + (EF_{OB, N2O} * BM_{OB, D} * 310) \quad \text{(Eq. 13)}$$

$$GHG_{DD} = EF_{DD, CH4} * BM_{DD} * 21 + EF_{DD, N2O} * BM_{DD} * 310 \quad \text{(Eq. 14)}$$

$$GHG_{LF} = EF_{LF, CH4} * BM_{DD} * 21 \quad \text{(Eq. 15)}$$

where:

EF_{OB} Emission factor for CO_2, CH_4 and N_2O from uncontrolled open pile burning of biomass. Recommend the use of:

- CO_2 : 1.73 tons CO_2 / ton dry biomass
- CH_4 : 0.005 ton CH_4 / ton dry biomass
- N_2O : 0.00015 ton N_2O / tons dry biomass

BF Biomass consumption burn out efficiency of the open pile burn. Recommend the use of 95%.

EF_{DD} Emission factor for CH_4 and N_2O from in-field decay and decomposition of biomass. Recommend the use of 0.05 ton CH_4 / ton dry biomass. Recommend the use of 0 tons N_2O / ton dry biomass.

EF_{LF} Emission factor for CH_4 from landfilling of biomass. Recommend the emission factor be determined using the procedure contained in the Climate Action Reserve Landfill Protocol for GHG Offset Projects.

5.3 Net GHG Project Reduction

Determine GHG reductions from biomass waste to energy recovery project, GHG_{NET}, as:

$$GHG_{NET} = GHG_{BASE} – GHG_{PROJ} \quad \text{(Eq. 14)}$$

6.0 Monitoring

Project data monitoring requirements are shown Form B.

7.0 Reporting and Recordkeeping

7.1 Project Commencement

Form A must be completed, submitted, and approved prior to project commencement, as discussed in Section 2.1 and Section 3.6.

7.2 Recordkeeping

Form B can be used to collect, maintain, and document the required information. Information is to be kept for a period of 10 years after it is generated, or 7 years after the last verification.

7.3 Reporting

Form C can be used to report on project emission reductions. Reporting must be made on a monthly basis.

Project developers must report GHG emission reductions on an annual (12-month) calendar basis.

8.0 Verification

Project activities and GHG emission reductions must be verified and certified by a qualified third party prior to GHG emission reduction issuance. The verifier must review and assess the reported data to confirm that is adheres with the all the requirements of this protocol; and determine that the emissions reductions are accurate, consistent, and credible. The third party verifier must be approved by the responsible entity that issues the emission reductions.

9.0 Glossary of Terms

Additionality: Biomass residue management practices that are above and beyond business as usual operation, exceed the baseline characterization, and are not mandated by regulation.

Biomass energy recovery operator: Entity that owns and/or operates a facility that processes and utilizes biomass waste as a feedstock to generate useful energy (electricity, heat, fuels).

Biomass generator: Landowner or independent contractor that conducts operations that result in the generation of biomass waste residuals.

Biomass waste residue: Non-fossilized and biodegradable organic material originating from plant material, which due to economic considerations are disposed of through open burning or deposited at the site of generation and left to decay and decompose or are transported to a landfill.

Carbon dioxide (CO_2): Greenhouse gas consisting of a single carbon atom and two oxygen atoms.

CO_2 equivalent (CO_{2e}): The quantity of a given GHG multiplied by its total global warming potential.

Emission factor (EF): A value for determining an amount of a greenhouse gas emitted for a given quantity of activity data (e.g. short tons of methane emitted per dry ton of biomass combusted).

Fossil fuel: A fuel, such as coal, oil, and natural gas, produced by the decomposition of ancient (fossilized) plants and animals.

Greenhouse gas (GHG): Includes carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs).

Global Warming Potential (GWP): The ratio of radiative forcing (degree to warming to the atmosphere) that would result from the emission of one unit of a given GHG compared to one unit of CO2).

kWh_e: Kilowatt-hour of electricity.

Methane (CH_4): Greenhouse gas with a GWP of 21, consisting of a single carbon atom and four hydrogen atoms.

MMBtu: Million British Thermal Units.

MWh_e: Megawatt-hour of electricity.

Nitrous oxide (N_2O): Greenhouse gas with a GWP of 310, consisting of two nitrogen atoms and a single oxygen atom.

Open burning: The intentional combustion of biomass material in piles for disposal without processing or energy recovery operations.

Project developer(s): An entity (or multiple entities) that undertakes a project activity, as defined in the Biomass for Energy Protocol. Project developers include, but are not limited to biomass waste generators, biomass waste energy recovery operators, and/or third party aggregators.

Syngas: Synthetic gas produced through industrial processing of biomass material into gaseous (i.e. methane) or further refined into liquid fuels (biofuels).

Third Party Aggregator: An entity that facilitates the project as is not the landowner, biomass waste generator, or biomass waste energy recovery operator for the purpose of generating GHG emission offset credits.

10.0 References

California Air Resources Board (CARB), Greenhouse Gas Inventory, 1990-2004, Nov. 17, 2007.

Delmas, R., J.P. Lacaux, and D. Brocard, "Determination of biomass burning emission factors: methods and results," Journal of Environmental Monitoring and Assessment, Vol. 38, pp. 181-204, 1995.

Intergovernmental Panel on Climate Change (IPCC), Fourth Assessment Report, Changes in Atmospheric Constituents and in Radiative Forcing, Chapter 2, pp. 211-216, 2007.

Jenkins, B., et al., Atmospheric Pollutant Emission Factors from Open Burning of Agricultural and Forest Biomass by Wind Tunnel Simulations, CARB Report No. A932-196, April 1996.

Kopmann, R., K. Von Czapiewski, and J.S. Reid, "A review of biomass burning emissions, part I; gaseous emission of carbon monoxide, methane, volatile organic compounds, and nitrogen containing compounds," Amos. Chem. Phys. Discuss., Vol. 5, pp. 10455-10516, 2005.

Mann, M. and P. Spath, "Life Cycle Assessment Comparisons of Electricity from Biomass, Coal, and Natural Gas," 2002 Annual Meeting of the American Institute of Chemical Engineers, National Renewable Energy Laboratory, Golden, Colorado, 2002.

U.S. EPA, Compilation of Air Pollutant Emission Factors, AP-42, Section 2.5, Open Burning, October 1992.

U.S. EPA, Compilation of Air Pollutant Emission Factors, AP-42, Section 13.1, Prescribed Burning, October 1996.

U.S. EPA, "Emission Facts – Average Carbon Dioxide Emissions Resulting from Gasoline and Diesel Fuel," EPA420-F-05-001, February 2005.

11.0 Emission Factors

<u>Methane Emission Factors for Open Burning of Biomass</u>

Reference / Burn Type	CH4 as reported by author	CH4 lb/dry ton fuel consumed
U.S. EPA, Compilation of Air Pollutant Emission Factors, AP-42, Section 13.1, Prescribed Burning, October 1996, Table 13.1-3.		
Broadcast Logging Slash		
Hardwood (fire)	6.1 g/kg fuel consumed	12.2
Conifer short needle (fire)	5.6 g/kg fuel consumed	11.2
Conifer long needle (fire)	5.7 g/kg fuel consumed	11.4
Logging slash debris dozer piled conifer (fire)	1.8 g/kg fuel consumed	3.6
D.E. Ward, C.C. Hardy, D.V. Sandberg, and T.E. Reinhardt, Mitigation of prescribed fire atmospheric pollution through increased utilization or hardwoods, pile residues, and long-needled conifers, Part III, Report IAG DE-AI179-85BP18509 (PNW-85-423), USDA Forest Service, Pacific Northwest Station, 1989.		
Broadcast Burned Slash		
Douglas fir	11.0 lb/ton fuel consumed	11.0
Ponderosa pine	8.2 lb/ton fuel consumed	8.2
Mixed conifer	12.8 lb/ton fuel consumed	12.8
Pile and Burn Slash		
Tractor piled	11.4 lb/ton fuel consumed	11.4
Crane piled	21.7 lb/ton fuel consumed	21.7
U.S. EPA, Compilation of Air Pollutant Emission Factors, AP-42, Section 2.5, Open Burning, October 1992, Table 2.5-5.		
Unspecified	5.7 lb/ton material burned	10.4
Hemlock, Douglas fir, cedar	1.2 lb/ton material burned	2.4
Ponderosa pine	3.3 lb/ton material burned	6.6
W. Battye and R. Battye, Development of Emissions Inventory Methods for Wildland Fire, prepared under Contract EPA No. 68-D-98-046, Work Assignment No. 5-03, February 2002. (Based on data from D.E. Ward and C.C. Hardy, Smoke emissions from wildland fires, Environment International, Vol. 17, pp. 117-134, 1991.)		
90% combustion efficiency	3.8 g/kg fuel consumed	7.6
B. Jenkins, S. Turn, R. Williams, M. Goronea, et al., Atmospheric Pollutant Emission Factors from Open Burning of Agricultural and Forest Biomass by Wind Tunnel Simulations, CARB Report No. A932-196, April 1996.		

Ponderosa pine pile burn	1.3 g/kg dry fuel	1.7
Almond pruning pile burn	1.2 g/kg dry fuel	2.6
Douglas fire pile burn	1.9 g/kg dry fuel	3.0
Walnut pruning pile burn	2.0 g/kg dry fuel	4.0

R. Kopmann, K. von Czapiewski, and J.S. Reid, A review of biomass burning emissions, part I; gaseous emission of carbon monoxide, methane, volatile organic compounds, and nitrogen containing compounds, Amos. Chem. Phys. Discuss., Vol. 5, pp. 10455-10516, 2005.

Literature search on biomass open burning	1 - 20 g/kg dry fuel	10.0

Nitrous Oxide Emission Factors for Open Burning of Biomass

Delmas, R., Lacaux, J.P., Brocard, D. "Determination of biomass burning emission factors: methods and results," Journal of Environmental Monitoring and Assessment, Vol. 38, 181-204, 1995.	0.00015 ton / ton dry

Methane Emission Factors for Decay and Decomposition of Biomass

Mann, M. K., and P. L. Spath, "Life Cycle Assessment Comparisons of Electricity from Biomass, Coal, and Natural Gas," 2002 Annual Meeting of the American Institute of Chemical Engineers. Golden, Colorado, National Renewable Energy Laboratory, 2002.	0.05 ton / ton dry

Assumes 9% carbon in biomass is converted to carbon in methane. Biomass has a molecular formula of $C_6H_{10}O_6$.

Nitrous Oxide Emission Factors for Decay and Decomposition of Biomass

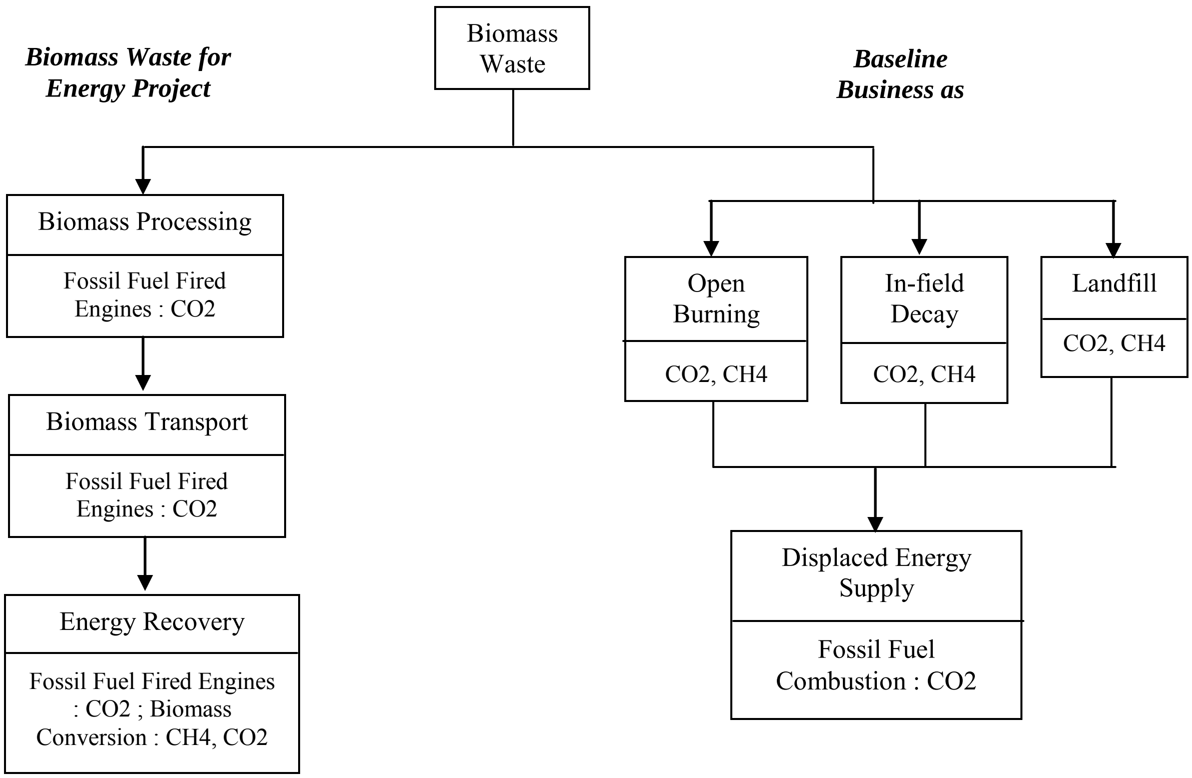
Engineering judgment. At temperatures of in-field decay and decomposition, N_2O is expected to be negligible. Nitrogen in fuel will go to NH_3.	0 ton /ton dry

12.0 Attachments

Table 1. Biomass for Energy Project -- Source Categories, GHG Sources, and GHG Emissions

Source	Associated GHGs	Included in GHG assessment boundary
Baseline		
Open Uncontrolled Pile Burning	CO_2	Included
	CH_4	Included
	N_2O	Included
In-field Decay and Decomposition	CO_2	Included
	CH_4	Included
	N_2O	Included
Landfill	CO_2	Included
	CH_4	Included
Biomass for Energy Project		
Transportation -- engine combustion of fossil fuels	CO_2	Included
	CH_4	Not included; negligible
	N_2O	Not included; negligible
Processing and Handling at Generation Site -- engine combustion of fossil fuels	CO_2	Included
	CH_4	Not included; negligible
	N_2O	Not included; negligible
Energy Recovery Facility	CH_4	Not included for combustors; may need to be included for other energy processing types
	CO_2	Included
	N_2O	Not included; negligible
Processing and Handling at Energy Recovery Facility – engine combustion of fossil fuels	CO_2	Included
	CH_4	Not included; negligible
	N_2O	Not included; negligible
GHGs from conventional energy production displaced by energy from biomass waste	Dependent on conventional energy source	Included

Figure 1. System Boundary Definition



Form A. Project Definition

Date:				
Project Title:				
Project Developer:				
Project Address:				
Anticipated Project Dates:	Start Date:		End Date:	
Permitting Status:				
Biomass Generation & Disposal Information				
Composition of Biomass (including moisture content)				
Historic, Current, and Anticipated Disposal Practice				
Biomass Generation Rate (green tons/day)				
Cost of Biomass Processing and Transport ($/green ton)				
Biomass Energy Recovery Information				
Type of Energy Produced	Electricity	Heat	Fuels	Other
Name & Location of Energy Recovery Facility				
Generation Rate of Recovered Energy (MMBtu/day)				
Users/Purchasers of Recovered Energy				

Form B. Monitoring and Recordkeeping

Date:			
Project Title:			
Project Developer:			
Start Date of Monitoring Period:		End Date of Monitoring Period:	

Monitoring and Parameter Measurements

Parameter	Description	Data Unit	How Measured	Measurement Frequency	Reported Measurement
$BM_{T,\,W}$	Biomass delivered to energy recovery facility	wet tons / delivery	Transport vehicle weight scale	Every separate delivered load	
M	Moisture content of biomass	moisture, wt. %	Sampling and analysis of biomass wastes	Every separate delivered load	
HHV_{BM}	Higher heating value of biomass waste	Btu/lb, dry	Sampling and analysis of biomass wastes	Periodic – at least once per month	
f	Energy production efficiency of energy recovery facility	net useful energy / biomass heat input	Measurement of boiler output and waste fuel input. Alternatively, based on manufacturer design specifications	Start of program; and updated as needed	
VM	Vehicle miles traveled for biomass transport	miles	Vehicle odometer	Periodically (at least weekly)	
MPG	Transport vehicle gas mileage	miles / gallon	Measurement of vehicle miles traveled and gas usage	Start of program, and updated as needed	

Parameter	Description	Data Unit	How Measured	Measurement Frequency	Reported Measurement
V_{FF}	Volume of fossil fuels used to power biomass processing equipment, e.g. shredders, chipper, grinders, conveyors, loaders, excavators, bulldozers	gallons	Measurement of diesel fuel usage and/or equipment operating hours	Periodically (at least weekly)	
X_{OB}	Fraction of biomass that would have been open burned	%, wet biomass	Determined based on current economics and operating practices	Start of program, and updated as needed	
X_{DD}	Fraction of biomass that would have been left in field to decay and decompose	%, wet biomass waste	Determined based on current economics and operating practices	Start of program, and updated as needed	
X_{LF}	Fraction of biomass that would have been landfilled	%, wet biomass waste	Determined based on current economics and operating practices	Start of program, and updated as needed	

Form C. Reporting

Date:	
Project Title:	
Project Developer:	
Reporting Period:	

Parameter	Description	Data Unit	Reported Value
$BM_{DD, D}$	Biomass left in field to decay	bone dry tons	
$BM_{OB, D}$	Biomass open burned	bone dry tons	
$BM_{LF, D}$	Biomass landfilled	Bone dry tons	
$BM_{T, D}$	Biomass delivered to energy recovery facility, adjusted for moisture	bone dry tons / delivery	
$BM_{T, W}$	Biomass delivered to energy recovery facility	wet tons / delivery	
E_{BM}	Energy produced from energy recovery facility	kWh	
$EF_{DD, CH4}$	Emission factor for in-field decay and decomposition	tons CH_4/ton dry biomass	
$EF_{DD, N2O}$	Emission factor for nitrous oxide from in-field decay and decomposition	tons N_2O/ton dry biomass	
EF_E	Emission factor for CO_2e for existing electricity generation	tons CO_2e/unit energy	
EF_{FF}	Emission factor for fossil fuel combustion	lb CO_2/gallon fuel	
$EF_{OB, CH4}$	Emission factor for methane from open pile burning	tons CH_4/ton dry biomass	
$EF_{OB, N2O}$	Emission factor for nitrous oxide from open pile burning	tons N_2O/ton dry biomass	
$EF_{LF, CH4}$	Emission factor for methane from landfill	tons CH_4/ton dry biomass	
f	Energy production efficiency of energy recovery facility	net useful energy / biomass waste heat input	

Parameter	Description	Data Unit	Reported Value
GHG_{AUX}	GHG resulting from ancillary biomass handling, processing, and transport	tons CO_2e	
GHG_{BASE}	GHG resulting from baseline disposal practices	tons CO_2e	
GHG_{DD}	GHG resulting from decay and decomposition	tons CO_2e	
GHG_{E}	GHG displaced from energy production from biomass	tons CO_2e	
GHG_{NET}	Net GHG reductions from	tons CO_2e	
GHG_{OB}	GHG resulting from open burning activities	tons CO_2e	
GHG_{LF}	GHG resulting from landfilling activities	tons CO_2e	
GHG_{PROC}	GHG resulting from ancillary biomass handling and processing	tons CO_2e	
GHG_{PROJ}	GHG resulting from the biomass waste to energy project	tons CO_2e	
GHG_{TRANS}	GHG resulting from transport operations	tons CO_2e	
HHV_{BM}	Higher heating value of biomass	Btu/lb, dry	
M	Moisture content of biomass	moisture, wt. %	
MPG	Transport vehicle gas mileage	miles / gallon	
Q_{BM}	Heat content per delivery of biomass at facility	MMBtu	
R_{FF}	Average volumetric fuel use rate for processing equipment	gallons/hour	
T_{FF}	Time equipment used for processing operations	hours	

Parameter	Description	Data Unit	Reported Value
V_{FF}	Volume of fossil fuels used to power biomass processing equipment, e.g. shredders, chipper, grinders, conveyors, loaders, excavators, bulldozers	gallons	
VM	Vehicle miles traveled for biomass waste transport	miles	
X_{DD}	Fraction of biomass that would have been left in field to decay and decompose	%, wet biomass	
X_{OB}	Fraction of biomass that would have been open burned	%, wet biomass	
X_{LF}	Fraction of biomass that would have been landfilled	%, wet biomass	

CAPCOA GHG Rx PROTOCOL:

Improvement of the Efficiency of a Natural Gas-Fired Boiler or Process Heater

(Based on Improvement of the Efficiency of a Natural Gas-Fired Boiler or Process Heater protocol approved in June, 2010 by the South Coast Air Quality Management District)

(Approved by the CAPCOA Board 2013)

This protocol has been modified from the SCAQMD Protocol: Improvement of the Efficiency of a Natural Gas-Fired Boiler or Process Heater. The changes include:

1. Making the protocol applicable to projects in California rather than just South Coast, and changing references to SCAQMD rules to EPA documents; and

2. Allowing the use of site-specific heating values, if approved by the local air district; and

3. Minor, non-substantive changes; and

4. This protocol cannot be used for projects on or after January 1, 2015.

CAPCOA GHG Rx PROTOCOL: Improvement of the Efficiency of a Natural Gas-Fired Boiler or Process Heater

I. Introduction

The purpose of this protocol is to establish a method to quantify voluntary reductions in greenhouse gas (GHG) emissions resulting from an improvement in the efficiency of a boiler or process heater (B/PH).

For practical purposes, the only GHG that is emitted in significant quantities from a B/PH is carbon dioxide (CO_2), therefore, this protocol focuses on CO_2 emission reductions. CO_2 emissions result from combustion of carbon in the fuel plus any CO_2 already contained in the fuel. Since CO_2 is the direct result of fuel combustion, any improvement in the efficiency of a B/PH will reduce fuel use and CO_2 emissions.

II. Definitions

For purposes of this protocol, the following definitions shall apply:

a) ADDITIONAL means that the greenhouse gas reductions achieved throughout the duration of the activity that generates certified greenhouse gas emission reductions are: a) not occurring due to routine equipment replacement; and b) are not otherwise required and would not occur as a result of any local, state, or federal regulation, or any legal instrument, to ensure no double counting of reductions unless authorized by the regulation or legal instrument. For the purpose of this protocol, a B/PH located at a facility under a GHG cap-and-trade program would not be eligible to generate certified GHG emission reductions.

b) A BOILER is any combustion equipment primarily used to produce steam or to heat water.

c) COMBUSTION EFFICIENCY of a B/PH is 100 percent minus percent flue loss (percent flue loss is based on input fuel energy), on a higher heating value basis.[1]

d) HIGHER HEATING VALUE (HHV) of a fuel is the high or gross heat content of the fuel with the heat of vaporization included. The water vapor is assumed to be in a liquid state.

e) A PROCESS HEATER is any combustion equipment which transfers heat from combustion gases to a process stream. Process Heater does not include any kiln or oven used for drying, curing, baking, cooking, calcining, or vitrifying; or any unfired waste heat recovery heater that is used to recover sensible heat from the exhaust of any combustion equipment.

[1] This definition is used by federal (10CFR431.82) and state efficiency regulations.

f) NATURAL GAS is a mixture of gaseous hydrocarbons, with at least 80 percent methane (by volume), and of pipeline quality, such as the gas sold or distributed by any utility company regulated by the California Public Utilities Commission.

g) A STANDARD CUBIC FOOT (SCF) is that mass of a gas that occupies one cubic foot at standard conditions of temperature and pressure—60 ^{o}F and 29.92 In. mercury.

h) THERMAL EFFICIENCY of a B/PH is the fraction of the input fuel energy, on a higher heating value basis, that is recovered as heat content of the water or steam product or the process stream.

III. Eligibility

a) This protocol is for B/PHs fired on natural gas only.

b) This protocol may be used for the following types of efficiency improvements on a natural gas-fired B/PH:

   1) Addition of a combustion air preheater, economizer or other system that reduces the flue gas exhaust temperature and increases the B/PH thermal efficiency.

   2) Addition of a system that monitors, controls and reduces the excess combustion air, i.e., an oxygen trim system (OTS).

c) The first written contractual commitment for the efficiency improvement must have occurred on or after January 1, 2009.

d) The B/PH must be located within California.

e) The efficiency improvement must be additional, as defined in Section II. Some examples of non-additional efficiency improvements are:

   1) If the B/PH or the upstream fuel used for the B/PH is included in a GHG cap-and-trade program, the GHG emission reductions will not be considered to be additional, and certified GHG emission reductions cannot be claimed.

   2) In the case of adding OTS, if the OTS is necessary for reduced NOx operation of the B/PH to meet the requirements of an Air District Rule , the GHG emission reduction does not qualify as additional.

   3) If the B/PH is subject to the California Appliance Efficiency Regulation [California Code of Regulations (CCR), Title 20, Division 2, Chapter 4, Article 4, Sections 1601-1608 or subsequent revisions], the minimum pre-improvement efficiency that may be used in calculating the GHG emission reduction must correspond to the minimum required by the regulations.

f) The equipment operator must notify the Executive Officer 30 days prior to commencing operation of the new or improved B/PH.

g) Projects that receive public grant money or rate payer rebates are not eligible for certified emission reductions under this protocol.

IV. Calculation Procedures for the GHG Emission Reduction and Other Emission Co-Benefits

a) Overall Approach

GHG emission reductions are determined after the end of each calendar year. No GHG emission reduction may be claimed for operation of the B/PH prior to the project initiation date. The project initiation date is the date on which the new or modified B/PH is placed into service.

The GHG emission reduction is the difference between the Modeled Baseline Emissions and the Project Emissions.

GHG reduction = Modeled Baseline Emissions (MBE) – Project Emissions (PE)

PE is the actual annual CO_2 emissions after the B/PH efficiency improvement has been implemented.

MBE are the emissions that would have occurred if the B/PH efficiency improvement measure had not been taken. MBE are calculated based on the PE, taking into account the B/PH thermal efficiency with and without the efficiency improvement.

To be consistent with the international convention for GHG emissions, PE and MBE are expressed in metric tons CO_2e per year.

If, during any portion of the year, the B/PH or the upstream fuel used for the B/PH was included in a GHG cap-and-trade program, the GHG emission reductions will no longer be considered to be additional, and certified GHG emission reductions can no longer be claimed. Co-benefits are to be calculated each year, but no credits will be issued for SIP approved rules. Co-benefits could be used for CEQA mitigation.

b) Project Emissions (PE)

Direct CO_2 emissions from natural gas combustion are calculated using the following equation[2].

$$PE = Fuel \times 1028\ \frac{Btu}{scf} \times 53.02\ \frac{kg\ CO_2}{MMBtu} \times 0.001\ \frac{metric\ tons}{kg}$$

Where:

PE = metric tons of CO_2 emissions

Fuel = volume of natural gas combusted, millions of standard cubic feet (scf)

[2] This equation is based on the procedure specified in 40 CFR §98.33 EPA Calculating GHG Emissions (http://www.gpo.gov/fdsys/pkg/CFR-2010-title40-vol20/pdf/CFR-2010-title40-vol20-sec98-33.pdf) and uses a U.S. default natural gas heating value of 1028Btu/scf from Table G.1 Local Government Operations Protocol (http://www.arb.ca.gov/cc/protocols/localgov/pubs/lgo_Protocol_v1_1_2010-05-03.pdf). .

1028 = default national pipeline average higher heating value, Btu/SCF (note: facility specific HHV may also be used if approved by local air district)

53.02 = default carbon dioxide emission factor, kg CO_2 per MMBtu

0.001 = factor to convert kg to metric tons

c) Modeled Baseline Emissions (MBE)

The calculation procedure for the MBE will depend of the type of B/PH efficiency improvement.

1) Retrofit of an Economizer or Combustion Air Preheater

An economizer improves the efficiency of a B/PH by reducing the exhaust temperature and transferring recovered heat to B/PH feed water or other fluid. A combustion air preheater is similar, but transfers the heat to the combustion air. Sufficient space should be allowed between the B/PH exhaust outlet and the economizer or air preheater inlet to measure B/PH exhaust temperature before the economizer or air preheater so that the B/PH efficiency can be determined with and without the economizer or air preheater.

The MBE will be calculated as follows:

$$\text{MBE} = \text{PE} \times \frac{\text{(thermal efficiency with economizer/air preheater)}}{\text{(thermal efficiency without economizer/air preheater)}}$$

2) Retrofit of an Oxygen Trim System (OTS)

An OTS improves efficiency by reducing the exhaust temperature and exhaust flow rate, thereby reducing the amount of stack heat losses. To determine the GHG emissions benefit, the thermal efficiency before and after installation of the OTS must be established. To provide the information needed to determine the thermal efficiency before the OTS is installed, the flue gas O_2 and temperature must be measured at the B/PH outlet before installation of the OTS.

The MBE will be calculated as follows:

$$\text{MBE} = \text{PE} \times \frac{\text{(thermal efficiency with OTS)}}{\text{(thermal efficiency before OTS installation)}}$$

For a B/PH that is subject to the California Appliance Efficiency Regulation [California Code of Regulations (CCR), Title 20, Division 2, Chapter 4, Article 4, Sections 1601-1608 or subsequent revisions], if the pre-improvement combustion efficiency is less than the minimum required by the regulation, the pre-improvement thermal efficiency value used in the MBE calculation must be increased from the measured value by the amount by which the measured combustion efficiency is below the required minimum.

V. Project Monitoring

a) Overview

Project developers are responsible for monitoring the performance of the project and operating the improved B/PH in a manner consistent with the manufacturer's recommendations, measuring annual B/PH fuel use with a dedicated fuel meter, and calculating actual B/PH thermal efficiency based on flue gas measurements. The thermal efficiency monitoring requirements, based on the type of project, are summarized in the following table.

Project Type	**B/PH Thermal Efficiency Monitoring**
Retrofit of an Economizer or Combustion Air Preheater	Annual test of B/PH thermal efficiency with and without economizer or combustion air preheater for Section IV c) 1) calculation
Retrofit of an Oxygen Trim System (OTS)	• One-time test of B/PH thermal efficiency without OTS for Section IV c) 2) calculation • Annual test of B/PH thermal efficiency to determine B/PH thermal efficiency with OTS for Section IV c) 2) calculation

Procedures to be used to calculate the B/PH efficiency, perform the required O_2 and temperature measurements and measure the fuel usage are presented below.

b) B/PH Thermal Efficiency

1) Boiler Efficiency Calculator

The procedures in this section are for determining the thermal or combustion efficiency before and after an efficiency improvement that is achieved by retrofitting an economizer, air preheater, or OTS to an existing B/PH. The efficiency of the improved B/PH must be checked annually using these procedures.

The American Society of Mechanical Engineers has a Power Test Code for Fired Steam Generators (PTC 4 – 1998) that requires detailed measurements of all inputs and all outputs. The test method is the most accurate one, but is unnecessarily complicated for the purposes of this protocol.

The Natural Resources Canada Office of Energy Efficiency has developed a simple and free online Boiler Efficiency Calculator tool that can determine the thermal or combustion efficiency of a B/PH with measurements of only the flue gas temperature and oxygen content, and the combustion air temperature. It is available at http://www.oee.nrcan.gc.ca/industrial/technical-info/tools/boilers/index.cfm?attr=24.

The Boiler Efficiency Calculator is based on the ASME's Power Test Code for Steam Generating Units (PTC 4.1-1964, re-affirmed 1973, also ANSI PTC 4.1-

1974, reaffirmed 1985). This is an older code that was replaced by the newer PTC 4-1998.

The calculator uses a simplified version of the Indirect Method from the older PTC 4.1 for determining efficiency, which calculates thermal efficiency by determining the major energy losses. The losses include:

- stack losses due to the flue gas, that are calculated based on the measured temperature and oxygen content. This is the majority of all losses.
- an estimate of radiation and convection losses; and
- unaccounted losses. For natural gas fuel, the calculator user should enter 0.1% for this minor loss.

The calculator will also calculate the thermal efficiency with and without a non-condensing economizer or a combustion air preheater.

For a B/PH that is subject to the California Appliance Efficiency Regulations, combustion efficiency will be determined with the Boiler Efficiency Calculator, but with radiation, convection and unaccounted losses set to zero, as required by federal and state regulations.

2) Correction for Condensing Economizers

Since the calculator assumes a non-condensing economizer, a correction must be added if the economizer is a condensing economizer. For this case, the fraction of the flue gas moisture that will condense is calculated from the flue gas exit temperature, and the efficiency calculated by the calculator is increased to account for the sensible and latent heat of condensation recovered from the water that condenses on the economizer surface. The calculation procedure is as follows.

A. Calculate the partial pressure of water in the flue gas.

$$PP = 2.8082 - 0.1168 \times O_2$$

Where PP = partial pressure of water, psia

O_2 = flue gas oxygen content, vol. % (dry)

This equation is based on the natural gas composition that is assumed in the calculator.

B. Calculate the vapor pressure of water at the flue gas exit temperature

$$VP = 9 \times 10^{-7} \times FGT^{3.0136}$$

Where VP = vapor pressure of water, psia

FGT = flue gas temperature at the economizer exit, ^oF

This equation is based on the water vapor pressure table in the ―Useful Tables" handbook published by the Babcock & Wilcox Co., Barberton, Ohio.

C. Calculate the fraction of the flue gas water content that will condense

$$F = 1 - VP/PP$$

Where F = fraction of flue gas water that will condense.

If F is not at least 0.1, the economizer is not a condensing economizer.

D. Calculate the sensible and latent heat (LH) of condensation that is recovered from the flue gas water that condenses.

$$EFF_{LH} = F \times .00935 \times (1087 + 0.467 \times FGT - CAT)$$

Where:

EFF_{LH} = heat reclaimed from condensed water as percent of fuel HHV, %

CAT = temperature of inlet combustion air to the B/PH, ^{o}F

This equation is based on the equation used in the calculator to calculate the heat loss associated with the flue gas moisture but is applied here only to the fraction of the flue gas water that condenses.

E. Calculate the corrected B/PH thermal efficiency.

$$EFF_{corr} = EFF_{calc} + EFF_{LH}$$

Where:

EFF_{corr} = thermal efficiency including reclaimed latent heat of condensation, %

EFF_{calc} = thermal efficiency with economizer, calculated using the calculator, %

c) Flue Gas/Combustion Air Measurements

1) Pre-Improvement Measurements

The determination of the thermal efficiency for an existing B/PH is sometimes required, as specified above, before an OTS is installed. The following requirements apply to the needed combustion air temperature, and flue gas exhaust temperature and oxygen content measurements:

- The measurements will be taken while the B/PH is operating within 5% of its most common in-service load (excluding low-fire standby operation). The operator must provide records, or other information if records do not exist, to substantiate the choice of this load.
- The measurements will be taken within 24 hours after the B/PH is tuned up in its normal manner. The operator must provide records to demonstrate that the B/PH has been tuned in the normal manner. (By

purposely mistuning a B/PH, the thermal efficiency can reduced, which would cause an over calculation of the GHG emission reduction from the efficiency improvement method.)

- The flue gas oxygen content measurements will be conducted using the equipment, calibration procedures, and sampling procedures of EPA's CTM-030 ~~"D~~etermination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers, and Process Heaters Using Portable Analyzers", except that:
    - .
- The flue gas exhaust temperature will be measured simultaneously with the flue gas oxygen measurements at the same three points, and the combustion air temperature will be measured simultaneously at one point located within one foot of the combustion air intake, but as far away from any hot surfaces as possible.

2) Post-Improvement Measurements for an OTS Retrofit

Since pre-improvement measurements are required for a B/PH before it will have an OTS installed, the post-improvement measurements must be conducted in the same manner as the pre-improvement measurements, i.e. at the same load, and with the same measurement procedures, except for the following:

- For a B/PH rated up to 5 MMBtu/hr, measurements must be conducted quarterly or every 2,000 unit operating hours, whichever occurs later. For a B/PH rated > 5 MMBtu/hr, measurements must be conducted monthly or every 750 operating hours, whichever occurs later.
- Measurements must be conducted at least every 250 operating hours or at least 30 days after any tuning or servicing of a B/PH..
- At least one measurement must be conducted in each calendar year.
- The thermal efficiency or combustion efficiency is calculated, as previously described using the Boiler Efficiency Calculator, each time measurements are made. The efficiency for a calendar year is the average of all the efficiency measurements in that calendar year.

3) Post-Improvement Measurements after Retrofit of a Combustion Air Preheater or Economizer

The post-improvement measurements following retrofit of an combustion air preheater or economizer are conducted in the same manner as described in the previous paragraph, except that:

- Because pre-improvement measurements were not required, the measurements must be taken while the B/PH is operating at its current most common in-service load ± 5%. The operator must provide records, or other information if records do not exist, to substantiate the choice of this load.

- Measurements of flue gas temperature and oxygen content must be taken simultaneously both upstream and downstream of the air preheater or economizer.
- The thermal efficiency without the economizer/air preheater is calculated using the measurements upstream of the economizer/air preheater.
- The thermal efficiency with the economizer/air preheater is calculated using the measurements downstream of the economizer/air preheater.

d) Determination of Fuel Usage

Any B/PH for which a GHG emission reduction is to be certified must have a dedicated fuel meter. The only exception is if the GHG emission reduction involves more than one B/PH and all involved units are identical, have the same average operating loads, and receive identical improvements. In that case, a common fuel meter may be shared by all involved units.

The fuel meter must have an accuracy of ±5% or better, as specified by the manufacturer, and must be maintained and calibrated in a manner and at a frequency required to maintain this level of accuracy.

If the fuel meter fails a calibration test (tested to be outside of allowable 5% margin of error), the fuel usage shall be assumed to be zero until the meter passes a subsequent calibration test. In the event that the fuel meter is inoperable, fuel usage shall be assumed to be zero during the period of inoperability.

The fuel meter must be installed, maintained and operated in a manner consistent with the manufacturer's recommendations; and must be tamper proof and, if a totalizer type, non-resettable. The seals installed by the manufacturer must be intact to prove the integrity of the measuring device. If the meter is unsealed for maintenance or repairs, it must be resealed by an authorized manufacturer's representative.

VI. Project Plan

The project developer must complete and submit for the approval of the local Air District, a Project Plan that includes: , fees required by the Air District and the Project Submittal Form in Appendix A prior to commencing the GHG reduction. All information in the plan, unless marked confidential, may be made publicly available.

VII. Project Recordkeeping and Reporting

a) Recordkeeping

For purposes of independent verification and historical documentation, project developers shall keep all information required by this protocol for a period of five years after the last calendar year for which a GHG emission reduction is claimed. Records shall include descriptions of all project equipment and methods and all data inputs and calculations for the calculation of the baseline emissions and project emission reductions. Records shall include, but not be limited to, the following data and information.

- B/PH make, model, serial number, rated input (Btu/hr, higher heating value), rated steam production (lb/hr) and conditions (psig and ^oF) or rated fluid throughput and inlet/outlet temperatures (^oF), design heat transfer to steam or fluid at rated input (Btu/hr), design thermal efficiency (%) based on 60 ^oF inlet air and feedwater temperature, and design flue gas exit temperature and O_2 content (vol. %, dry).
- Make, model, serial number of economizer, combustion air preheater or OTS and Air District permit application or permit number if applicable.
- Evidence of startup of the improved B/PH by the manufacturer or engineering firm, including the startup date.
- Fuel meter make, model, serial number.
- Method used to measure flue gas and combustion air temperatures.
- O_2 analyzer make, model, serial number.
- Fuel meter and O_2 analyzer calibration methods and results.
- QA/QC procedures and data.
- Fuel meter data that documents annual fuel usage.
- Flue gas O_2, flue gas temperature and combustion air temperature data.
- B/PH efficiency determinations using the Boiler Efficiency Calculator: computer screen-prints showing input data and results.
- Annual calculations: PE, MBE, GHG emission reductions and any co-benefits realized. [See Section VIII(a)].

b) Reporting

Project developers must annually report to the local Air District, within 60 days of the end of each calendar year, the GHG emission reductions associated with a B/PH efficiency improvement that occurred the preceding year. Each annual report shall contain all data and calculations required to compute the GHG emission reduction for the year. Data and calculations to be included in the annual report shall include, but not be limited to, the following:

- Fuel meter make, model, serial number.
- Method used to measure flue gas and combustion air temperatures.

- O_2 analyzer make, model, serial number.
- Fuel meter and O_2 analyzer calibration methods and results.
- QA/QC procedures and data.
- Fuel meter data that documents annual fuel use.
- Flue gas O_2, flue gas temperature and combustion air temperature data.
- B/PH efficiency determinations using the Boiler Efficiency Calculator: computer screen-prints showing input data and results.
- Calculations: PE, MBE, GHG emission reduction and any other emission co-benefits. [See Section VIII(a)]

VIII. Appendices

a) Co-Benefits

Co-benefits are reductions of criteria pollutant emissions that are achieved because of the GHG-reduction project. B/PH co-benefits may include emission reductions of oxides of nitrogen (NOx), carbon monoxide (CO), volatile organic compounds (VOC) and particulate matter (PM). The co-benefits are calculated from the B/PH emission rates expressed as lb/MMBtu.

For NOx, the B/PH emission rate is based on the B/PH Air District permit limit if one exists or the appropriate emission factor in Table 1.4-1 within EPA AP42 Fifth Edition Volume 1 Chapter 1: External Combustion Sources , whichever is lower. If the NOx limit is expressed as ppmvd (volumetric parts per million on a dry basis) corrected to 3% O_2, it may be converted to lb/MMBtu using the following formula based on USEPA Method 19:

$$\text{Lb/MMBtu NOx} = \text{ppmvd @ 3\% } O_2 * .00121,$$

For CO, the emission rate is based on the permit limit if it is 100 ppmvd or less (corrected to 3% O_2). Otherwise the emission rate is based on the default emission factor of 84 lb/MMSCF fuel is used from Table 1.4-1 within EPA AP42 Fifth Edition Chapter 1. If a permit limit is used, the conversion to lb/MMBtu is as follows (based on USEPA Method 19):

$$\text{Lb/MMBtu CO} = \text{ppmvd @ 3\% } O_2 * .000737$$

If the 84 lb/MMSCF factor is used, the equivalent lb/MMBtu is .0818 based on 1028 Btu/SCF fuel HHV.

For VOC and PM, since there are typically no permit limits, the following emission rates, which are based on EPA AP 42 emissions factors and 1028 Btu/SCF fuel HHV, are used:

$$\text{Lb/MMBtu VOC} = 5.5 \text{ lb/MMSCF} /1028 = .0054$$

$$\text{Lb/MMBtu PM} = 7.6 \text{ lb/MMSCF} /1028 = .0074$$

For each pollutant, the emission reduction is calculated from the GHG emission reduction using the lb/MMBtu emission rate:

$$\text{Emission Reduction (tpy)} = \frac{(\text{MBE} - \text{PE}) \times \text{Pollutant lb/MMBtu}}{(53.02 \text{ kg/MMBtu}) \times 2}$$

b) Project Submittal Form

The following form is to be used for reporting general project information to the Air District in order to initiate the project listing process. All fields must be completed as thoroughly as possible. If a field is not applicable, insert N/A in the space provided. If the project is still in the planning/development phase, all fields must be completed using best available data and estimations.

Application Number: ______________________

GHG Project Number: ______________________

APPENDIX A:

VOLUNTARY GREENHOUSE GAS (GHG) EMISSION REDUCTION BY EFFICIENCY IMPROVEMENT OF A NATURAL GAS-FIRED BOILER OR PROCESS HEATER

PROJECT SUBMITTAL FORM

INSTRUCTIONS					
The following form is to be used for reporting general project information to the AQMD in order to initiate the project listing process. All fields must be completed as thoroughly as possible. If a field is not applicable, insert N/A in the space provided. If the project is still in the planning/development phase, all fields must be completed using best available data and estimations. Submit one form for each boiler and/or process heater (B/PH). Information in this plan is available to the public, unless noted as confidential and qualified for non-disclosure under the California Public Records Act. The applicant must also submit with this form, information and fees required by the project proponents local Air Pollution Control District.					
PROJECT INFORMATION					
Project Developer					
Organization:					
Responsible Individual:					
Address:		City:		Zip Code:	
Phone:	- -	Email:			
Project Location					

Facility Name:		Facility Address:	
Project Start Date			
Description of the Boiler or Process Heater (B/PH)			

Make:		Model		Rated Input (Btu/hr)	

Rated Steam Production (lb/hr):		Conditions (psig and °F):	
OR Rated Fluid Throughput and inlet/outlet temperatures (°F)			
Design Heat Transfer to steam or fluid (Btu/hr) at Rated Input			
Thermal Efficiency (%) at Rated Input Based on 60°F Inlet Air			
Design Flue Gas Exit Temperature (°F) and O_2 content (vol. %, dry)			
Minimum Efficiency for this model in the CA Appliance Efficiency Regulation (CA Code of Regulation Title 20, Div. 2, chapter 4, Article 4, Sections 1601-1608 or subsequent revisions), if applicable			
The emission reductions from this project will be registered with another registry or program besides the CAPCOA GHG Rx?	❒ No ❒ Yes - If yes, name of registry ___________________		

EFFICIENCY IMPROVEMENT EQUIPMENT DETAILS			
Type of Equipment to be added:	❒ Economizer ❒ Combustion air preheater	❒ Oxygen trim system ❒ Other ________________________________	
Make:		Model:	
Design Flue Gas Exit Temperature (°F)			
Design O_2 content (vol. % dry):		Improved efficiency Expected (%):	
AQMD permit # (if required)		Status of permit/application:	

MEASUREMENT METHODS					
Fuel Meter					
Make:		Model:		Range (scfh)	
Fuel Meter Calibration Method:					
Flue Gas O_2 Analyzer					
Make:		Model:		Range (%)	
Flue Gas Analyzer Calibration Method:					

MONITORING PLAN

Specify below all initial and annual data to be recorded, frequency of measurements if more frequent than annual, frequency of calibrations, in what form and at what location records will be kept. Records must indicate all measurements, calibrations, inspections and cleanings. The fuel meter must be inspected, cleaned and calibrated at least bi-annually and the O_2 analyzer must be calibrated within ten days prior to each use.

CERTIFICATION

This project is not required by any local, state or federal regulation, or other legal instrument.

❒ Yes

❒ No

Signature	Title	Date

For AQMD use only:

AQMD Application Number: ___________________________ GHG Project Number: ________________________________

Date Application Received: ________________________________ Received by (AQMD Staff): ___________________________

CAPCOA GHG Rx Protocol:

Case by Case Project Protocol

California Air Pollution Control Officers Association

Greenhouse Gas Reduction Exchange

Appendix D

CAPCOA GHG Rx Quality Criteria:

Protocol for Case by Case GHG Emission Reductions

&

Criteria for Evaluation of New Protocols

Update

Adopted by the CAPCOA Board of Directors

August 12, 2015

(*Initially adopted November 6, 2012)*

Table of Contents

INTRODUCTION

Purpose of the Exchange

The California Air Pollution Control Officers Association (CAPCOA) has established the Greenhouse Gas (GHG) Reduction Exchange (Exchange) to support the creation and exchange of high quality, locally generated GHG emission reduction credits. Essentially, credits are created when projects or practices are implemented specifically to reduce GHG emissions that are not required by law or other mechanisms to reduce emissions, and the resulting reductions are validated by CAPCOA members. The GHG emission reductions, or credits, that meet the criteria and methodology described below, could be used as a source of mitigation for land use or other projects subject to the California Environmental Quality Act (CEQA) or for other GHG mitigation needs.

The Exchange accommodates two primary types of GHG credits:

1) those that are created according to an approved protocol based on reductions from a specific type of GHG emission source, and
2) those that are created according to this *Protocol for Case by Case Emission Reductions*, and are enforceable via:
    - an air district permit , or
    - another mechanism, such as an enforceable CEQA mitigation requirement

Reductions that fit the first type are generally subject to an annual validation process, which assures that a specific quantity of reductions did occur during the past year (vintage). These verified reductions are then listed as verified on the Exchange for that vintage, and are generally available for mitigation or other market purposes.

Reductions fitting the second type are generally found during the analysis of the reduction to be enforceable for a given period, for instance, via adequate conditions of approval contained in, and enforceable through, an air district Permit to Operate. These credits are not subject to annual validation, but are enforced on an ongoing basis via air district enforcement of those conditions.

For transparency purposes, CAPCOA will post the relevant protocol or other ERC evaluation documentation with each credit listed on the Exchange.

High Quality Credits

The Exchange will only list GHG emission reduction credits that have been created in accordance with CAPCOA-approved criteria and methodology that defines the following overarching principles that the GHG emission reductions must be:

- Real
- Additional/Surplus
- Quantifiable
- Validated
- Enforceable
- Permanent

This document provides guidance on the requirements that must be met for anyone wanting to implement projects or practices to reduce or sequester GHG emissions and list those GHG reduction credits on the CAPCOA Exchange. The GHG reduction projects or practices must have been implemented and the actions creating the reductions must have already occurred, or been committed to, in order to list the credits on the Exchange. The requirements listed in this document apply to the development of protocols that would be used to approve individual GHG reduction projects, such as: the Climate Action Registry's Urban Forestry Protocol; the approval of GHG reduction projects that are subject to air district permits, such as energy efficient boilers; or GHG reduction projects that are enforceable through some other mechanism, such as energy efficiency upgrades that are additional at existing residential or commercial properties and are enforceable through a CEQA mitigation requirement. Only GHG emission reductions that meet all of the criteria listed below qualify for listing on the CAPCOA GHG Reduction Exchange. Air district staff within the respective air basin where the credits are created will review the applicant's GHG reduction analysis to determine if they meet the overarching principals for high quality credits.

How to Use this Document

This document is intended for use by anyone proposing to submit GHG emission reduction credits to the CAPCOA Exchange, or to submit a GHG emission reduction protocol to CAPCOA for consideration for use by the Exchange. In either case, the proponent must supply adequate information to clearly demonstrate how all the eligibility criteria and other requirements set forth in this document have been met. Air district staff will review only the information submitted to determine if a proposed protocol or project meets CAPCOA's definition of high quality GHG emission reduction credits.

A.
OVERVIEW

A1. PROJECT PROPONENT AND LOCATION OF EMISSION REDUCTION

The project proponent must provide full contact information, roles and responsibilities of specific individuals, other significant project participants, relevant regulator(s) and/or administrators of any greenhouse gas (GHG) program(s) in which the project is already enrolled, and any entities holding credit and land title (if applicable).

Emission reductions must have occurred within California. Note that for emission reductions due to electrical efficiency projects that otherwise meet all eligibility criteria, only the efficiency project must have occurred within California. It is not necessary to validate that the resulting decrease in electricity generation occurred in California as well.

A2. METHOD OF EMISSION REDUCTION

Protocols specific to a particular type of project must define the type of emission reduction project for which the protocol is applicable. Such applicability criteria must be sufficiently restrictive such that eligible projects are consistent with the assumptions used in developing the protocol.

This protocol for case by case emission reduction projects requires that a detailed description of the actions taken that generated the emission reduction along with the date that such emission reductions occurred must be provided by the applicant.

The following items must be provided by the applicant:

- *Project purpose(s) and objective(s)*
- *Description of project activity*
- *Description of how the project will achieve GHG reductions and/or removals (sequestration)*
- *Description of how the project will comply with each of the emission reduction eligibility criteria detailed below.*

A3. GREENHOUSE GAS EMISSION REDUCTION ELIGIBILITY CRITERIA

The CAPCOA GHG Reduction Exchange will only recognize GHG emission reduction credits of the highest quality. The discussion below defines criteria and provides guidance when proposing new protocols, and serves as the protocol for case by case emission reduction projects. Drawing from current widely-accepted best practices, the CAPCOA Exchange will only accept GHG emission reduction credits that are real, additional/surplus, quantifiable, validated, enforceable and permanent. Greenhouse gas emission reductions that meet the criteria listed below could be acceptable by CAPCOA and eligible for listing in the Exchange.

The following criteria are applicable to new protocols approved by CAPCOA and, along with the rest of these guidelines, serve as the protocol for case by case emission reductions. Proponents of either protocols or projects must clearly demonstrate how all these eligibility requirements have been met.

In response to issues raised by interested parties, in late October 2014, CAPCOA initiated extensive research to review the Rx's use and definition of a key component of its additionality criteria, i.e., fiscal *additionality. Three primary areas were researched: other registries/Cap & Trade programs; protocols; and credit projects to determine if fiscal additionality was utilized (and the use of other additionality criteria). The review included 9 registries; 28 protocols; and 14 credit projects. After the registries were reviewed, the research then focused upon CARB and CARB-approved registries (CAR, ACR, VCS) in addition to the CAPCOA GHG Rx as it was determined that international bodies were generally not relevant due to differing pressures and factors than U.S. and California programs. The research and review took several months to complete.*

The review revealed that fiscal additionality (or "fiscal test") was used infrequently, in forestry protocols, CAPCOA GHG Rx District-initiated protocols, and to a lesser extent in some livestock protocols. Other additionality criteria used included: regulatory for all/most; exceeds common practice (CP) or beyond business as usual (BAU); implementation barriers (fiscal, technological, institutional); performance standards (often with a list of approved methods) – performance standards were often used to complement exceeds CP/BAU findings.

CAPCOA's additionality definition previously required meeting both a regulatory and fiscal test. Based on the results of this extensive review, CAPCOA amended its additionality definition to include meeting the regulatory test AND meeting one of the following three criteria: exceeds or goes beyond CP/BAU; OR, meeting the fiscal test (as defined); OR, a finding that there is an institutional or technological barrier to the project. The fiscal test definition was also expanded further than the previous definition. See "Additional/Surplus" below for more information on these revised definitions. Prior to implementing these changes, both the California Air Resources Board and the Governor's Office of Planning and Research were consulted; they reviewed and agreed with CAPCOA's revisions to these definitions/criteria.

In addition, CAPCOA found that its language within the Regulatory Surplus Test discussion regarding relationships with California's cap and trade regulation was overly restrictive. Working with upper management of the California's Air Resources Board, this language has also been revised herein.

Real

Emission reductions must be determined to be real, i.e. to have actually occurred. A real GHG emission reduction is the result of a project that yields quantifiable and validated GHG emission reductions and/or removals. Only the emission reductions occurring due to the specific action or project are considered. Reductions that have occurred since January 1, 2007, may be considered under this program, provided they meet all other eligibility criteria contained in this document. Reductions that occurred on or after January 1, 2005 may be eligible for credits on the Exchange provided they follow the SJV GHG credit rule and meet all the criteria in this document. Emission reductions that are planned or expected are not eligible for listing on the CAPCOA Exchange as credits, but projected future reductions may be included for informational purposes. However, once such an emission reduction does occur, it may be eligible for inclusion in the Exchange.

New protocols must include criteria that will ensure that the type of project covered by that protocol will result in a real emission reduction. The emission reduction must have actually occurred due to the specific actions taken by an applicant.

This protocol for case by case emission reduction projects requires that the reviewing air district determine, based on the information submitted, that the emission reduction claimed to have occurred from a particular device, process or practice due to actions taken by the applicant did in fact actually occur. For instance, enforceable permit conditions or CEQA mitigation requirements can be used to assure that reductions have occurred.

Additional/Surplus

Emission reductions must be determined to be additional and surplus. Projects must have occurred after January 1, 2007 unless a CAPCOA approved protocol allows an earlier date. In no circumstances can any project be given credits for reductions occurring prior to January 1, 2005.

Additional/Surplus is the condition of GHG emission reductions wherein they are determined to be in excess of requirements and what would otherwise occur. This must include a regulatory test, and a demonstration that the protocol or project meets at least one of the following criteria:

1) The action exceeds common practice, or goes beyond "business as usual." Performance standard(s) may be included in the protocol to establish a CP/BAU determination; or
2) The project would not be economically attractive based on the fiscal test as defined; or
3) There is an institutional or technological barrier to this type of project.

Regulatory surplus test

To be additional and surplus, an emission reduction must not be due to an action that is required by a law, rule, or other requirement. A project passes the legal requirement test when there are no laws, statutes, regulations, court orders, environmental mitigation agreements, permitting conditions or other legally binding mandates requiring its implementation, or requiring the implementation of similar measures that would achieve equivalent levels of GHG emission reductions.

An emission reduction that is in excess of what is required by any and all rules or laws would be considered additional and surplus of all requirements and therefore eligible as a credit. An emission reduction that is in excess of that which is required by any and all GHG rules or laws would be considered additional and surplus of all GHG requirements and therefore eligible as a credit, but this credit should be noted or conditioned as "additional and surplus of all GHG requirements." This distinction is important because some approaches for addressing GHG impacts under CEQA allow for the use, as mitigation, of GHG reductions that are additional and surplus to GHG regulations, and therefore either type of credit discussed above can be used for mitigation. GHG reductions that occur concurrently with an action that is required by a rule not directed at reducing GHGs may be additional and surplus of all requirements for the amount of reductions that are due to over-compliance with the regulatory requirement.

Finally, reductions that occur at facilities[1] with direct compliance obligations under California's cap and trade regulation are not eligible as credits. For the purposes of this section, covered entities (facilities) are stationary sources determined pursuant to the Cap-and-Trade Regulation sections 95811 and 95812.

Common Practice/Business as Usual (CP/BAU)

A determination of "exceeds" CP or "beyond" BAU may be based on performance standards, industry practices or other information/data to document that a protocol or project exceeds CP/BAU. This determination is based on the industry sector rather than a percentage cutoff (which may be potentially arbitrary). The key question in making this determination is - In the field or industry/sector, is there widespread deployment of this project, technology, or practice within the relevant geographic area?

Fiscal test

The fiscal test shall demonstrate that a project is not economically attractive or viable (e.g., the project costs exceed returns) under current conditions and may be based on: 1) a quantitative analysis which is developed using procedures in the GHG Rx-approved protocol or through a case-by-case project-specific analysis; or, alternatively, 2) use of industry-wide practice evaluations, reports or surveys either delineated in the GHG Rx-approved protocol or through a case-by-case project-specific evaluation (may be demonstrated based on quantitative or qualitative data).Institutional or Technological Barriers

Institutional barriers may include significant organizational, governmental, regulatory, cultural or social barriers to implementation. Technological barriers may include significant R&D deployment risk, uncorrected market failures, lack of trained personnel and supporting infrastructure for technology implementation, or lack of knowledge on a practice/activity.

<u>*Quantifiable*</u>

Emission reductions must be quantifiable through tools or tests that are reliable and give confidence to qualify for emission reduction credits. Quantification of the emission reduction requires establishing a baseline emission level and emission reductions resulting from the project. Emission reductions can be

[1] As clarification, refers to reductions that occur at the *physical location* of the facility.

quantified by comparing baseline emissions and actual post-project emissions or by comparing baseline emissions to potential post-project emissions, if the potential post-project emissions are enforceable through a permit or other mechanism. The latter method will result in a lower calculated actual emission reduction.

Baseline emissions (the actual emissions representative of normal operation before the emission reduction project) must reflect actual process data and/or practices that are representative of the operation. The potential emissions before the project cannot be used to determine baseline emissions.

Emission estimates must be based on correct, applicable methodologies, such as appropriate emission factors and source tests methods that are conducted properly and reviewed by trained staff. Adequate documentation to validate throughput or other information is also essential.

Validation

Emission reductions must be validated to qualify for emission reduction credits. The action taken to produce credits can be audited and there is sufficient evidence to show that the reduction did occur and was quantified correctly. Validation and enforcement ensure that the respective emission reductions remain real and permanent for a given time period. Sufficient information should be disclosed to allow reviewers and verifiers to make decisions about the credibility and reliability of GHG reduction claims with reasonable confidence.

Emission reductions are quantified and verified on a periodic basis – usually annually, although validation of some credits that are enforceable through other mechanisms (such as a permit enforcing a case-by-case reduction determination) may only have to be verified once, at the time the reductions are originally analyzed. For emission reductions quantified by comparing actual emissions before the project to actual emissions after the project, emission reductions that actually occurred during the previous period are quantified. This requires a comparison of actual emissions without the project compared to actual emissions with the project. These calculations are verified by participating air districts or an approved independent third party approved by CAPCOA to perform such validations. After a successful validation process, emission reduction credits are issued for that past period. Validation includes the review of documentation, monitoring data and procedures used to estimate GHG reductions.

Enforceable

There must be an enforceable mechanism in place to ensure that the action is, or was, implemented correctly, such as a permit condition or contractual agreement. In cases where the emission reduction is based on the difference between pre-project actual emissions and post-project potential emissions, the post-project potential emissions must be made enforceable by the entity issuing the emission reduction credits. Enforcement mechanisms can include a District issued permit, a local jurisdiction's conditions of approval, or a contract between the project proponent and the lead agency. Such mechanisms would specify design, operational, usage limits, monitoring, and recordkeeping requirements for the project to ensure that the parameters used in quantifying the actual emission reductions are being satisfied on an *ongoing basis. Any violation of the permit or contract terms and conditions would be subject to enforcement action by the District or lead agency and could result in credits being revoked.*

Permanent

Emission reductions must be permanent to qualify for emission reduction credits. Permanence refers to the longevity of an emission reduction or removal, and the risk of reversal of the action creating the reduction or removal. To be considered permanent, emission reductions or removals must continue to occur for the reasonable expected life of the emission reduction project.

Permanence can be affected by the shift, or "leakage" of emissions from an emission reduction project at one location or process to emission increases at other locations or processes outside the project boundary. Leakage can occur due to a shift in activity away from the emission reduction project to other sources outside the project boundary, resulting in no net reduction in overall emissions.

In making a determination if an emission reduction is permanent, the protocol (or the applicant in a case by case determination) must define the project boundary. The project boundary is the project's geographical implementation area, the types of GHG sources and sinks involved and the expected duration of the project. Within that project boundary, an evaluation is made to determine if the emission reduction is permanent, i.e. not shifted to other sources of emissions.

Generally, the emission reductions are considered to be permanent within the confines of the project boundary used in establishing the actual emission reductions. The adequacy and sufficiency of the subsequent use of the emission reductions as mitigation for CEQA purposes within that project boundary would be determined by the lead agency.

GHG emission reductions credits that meet all of the above criteria may qualify for listing on the CAPCOA Greenhouse Gas Reduction Exchange.

B.

METHODOLOGY

Quantification should employ rigorous and conservative accounting methods and assumptions for all project types. GHG emission accounting must achieve sufficient accuracy to enable users to make decisions with confidence as to the integrity of the reported information. Quantification of GHG reductions must be conducted within acceptable levels of uncertainty.

Where accuracy is difficult to achieve, quantification should err on the side of being conservative with GHG reduction estimates. Conservative assumptions, values, and procedures should be used to ensure that GHG reductions are not over-estimated. Conservative estimation methods should be used whenever data and assumptions are uncertain and measures to reduce uncertainty would be impractical.

To that end, protocol proposals and case-by-case reduction analyses should address each of the following issues according to the instructions provided.

B1. PROJECT BOUNDARIES AND LEAKAGE

Identify the physical and temporal boundaries of the project. Identify any opportunities for leakage to occur. Describe how leakage is accounted for and quantified. Provide sample calculations wherever possible.

B2. IDENTIFICATION OF GHG SOURCES AND SINKS

Identify the GHG sources and sinks within the project boundaries. If any sources or sinks will be considered de minimis*, include a justification. The de minimis threshold is generally defined as 3% of the final calculation of emission reductions or removals, unless some other de minimis threshold is appropriately justified. Detail the GHG quantification methodology for the project scenario including all relevant emissions or removals. Provide sample calculations.*

B3. BASELINE

Describe the baseline scenario, how the baseline was identified and chosen, and why it is the most appropriate baseline for the project. If the underlying protocol does not specify what years can be chosen for the baseline, the last 2 years are to be used, unless the air district evaluating the credits agrees that another 2 year consecutive period in the last 5 years is more representative. Address all baseline-related topics required by the Eligibility Criteria in section A3 above. Detail the GHG quantification methodology for the baseline scenario including all relevant emissions or removals. Provide sample calculations.

B4. PROJECT SCENARIO

Describe the project scenario, including the project actions that will take place and any additional information required by the Eligibility Criteria in section A3 above.

B5. REDUCTIONS AND ENHANCED REMOVALS

Describe how the project reduces GHG emissions or enhances the removal of GHGs from the atmosphere beyond what would have taken place in the baseline scenario. Detail the quantification methodology for identifying net reductions and removal enhancements, taking into account leakage and uncertainty.

Provide sample calculations wherever possible. Describe how uncertainty is accounted for and quantified.

B6. FUTURE PROJECTS

In some cases, a project proponent may propose a future emission reduction activity for the purposes of developing bankable emission reductions at a later time. This protocol could be applied to that future activity and resulting emission reductions could be banked on the Exchange once they are realized and verified.

B7. PERMANENCE

Demonstrate whether the project's GHG reductions face any risk of reversal by identifying any risks that may substantially affect the project's GHG emission reductions or removal enhancements. If the credits do face a risk of reversal, describe what method of permanence assurance will be used.

C.
MONITORING

C1. EMISSION REDUCTION MONITORING

Emission reductions are quantified and verified on a periodic basis – usually annually. For emission reductions quantified by comparing actual emissions before the project to actual emissions after the project, emission reductions that actually occurred during the previous period are quantified. This requires a comparison of actual emissions without the project compared to actual emissions with the project. These calculations are verified by a participating District or an independent third party approved by CAPCOA to provide such validation. After a successful validation process, emission reduction credits are issued for that past period. Validation includes the review of documentation, monitoring data and procedures used to estimate GHG reductions.

C2. MONITORED DATA AND PARAMETERS

List all relevant data and parameters that will be monitored. The table below provides an example of how monitoring data and parameters can be identified. Provide all relevant information, such as that listed in the table below, for as many distinctly monitored types of data/parameters as are included in the project.

Data or parameter monitored: ____

Unit of Measurement	
Description	
Data Source	
Measurement Methodology	
Data Uncertainty	
Monitoring Frequency	
Reporting Procedure	
QA/QC Procedure	
Notes	

D.
PROJECT TIMELINE

D1. START DATE

Provide the project start date - the date upon which the project began/will begin to reduce GHG emissions below its baseline

D2. PROJECT TIMELINE

Provide a timeline for project activities including:

- *Project term – the minimum length of time for which a project proponent commits to project continuance, monitoring and validation*
- *Crediting period – the length of time during which a project can generate creditable emission reductions below its baseline*
- *Frequency of monitoring, reporting and validation or other enforcement mechanism*
- *Target dates for major project activities (milestones)*

E.

PUBLIC NOTICE AND COMMENT

Coal Mine Methane Project Protocol Version 1.1

Protocol Summary

CLIMATE ACTION RESERVE

Project Definition

The installation and operation of any device, or set of devices, that results in the destruction of methane gas that would otherwise have been vented to the atmosphere from an active underground coal mine, as well as Mine Safety and Health Administration (MSHA) Category III trona mines.

Includes:

- A project destroying methane from a methane drainage system
- A project destroying ventilation air methane (VAM) from ventilation shafts

Project Eligibility Requirements

Location: Project must be within the United States or its territories or on U.S. tribal lands.

Start Date: Project must be submitted no more than six months after the project start date.

Performance Standard Test: The performance standard is confirmed once each crediting period.

- Drainage projects: any destruction device other than injection into a natural gas pipeline for offsite consumption
- VAM projects: any destruction device that destroys VAM

Legal Requirement Test: Project developer attests that there are no legal requirements for destruction of coal mine methane at the project site. The project is subject to a review of the Legal Requirement Test for each verification period.

Crediting Period: Project is eligible to receive credits for 10 years from start date or until failure of the Legal Requirement Test. Project may apply for a second 10-year crediting period.

Reporting and Verification Schedule: Annual verification at a minimum; reporting period can be no longer than 12 months. Sub-annual reporting and verification is allowed.

Other Eligibility Requirements:

- Clear ownership of GHG emissions reductions
- Project must not be registered with any other registry for the same vintages of reductions
- Proper accounting and monitoring
- Project activities must be in material compliance with all applicable laws

Project Exclusions

- Methane sent through a pipeline for offsite consumption
- Projects that operate at surface mines
- Projects that destroy methane from abandoned mines
- Projects that destroy virgin coal bed methane
- Projects that use any fluid/gas to enhance coal mine methane drainage
- Displacement of fossil fuel consumption associated with production of electric power for the grid

Important Note: This is a summary of the protocol. Please read the full protocol for a complete description of project requirements.

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Coal Mine Methane Project Protocol
Version 1.1
ERRATA AND CLARIFICATIONS

The Climate Action Reserve (Reserve) published its Coal Mine Methane (CMM) Project Protocol Version 1.1 in October 2011. While the Reserve intends for the CMM Project Protocol V1.1 to be a complete, transparent document, it recognizes that correction of errors and clarifications will be necessary as the protocol is implemented and issues are identified. This document is an official record of all errata and clarifications applicable to the CMM Project Protocol V1.1.[1]

Per the Reserve's Program Manual, both errata and clarifications are considered effective on the date they are first posted on the Reserve website. The effective date of each erratum or clarification is clearly designated below. All listed and registered coal mine methane projects must incorporate and adhere to these errata and clarifications when they undergo verification. The Reserve will incorporate both errata and clarifications into future versions of the protocol.

All project developers and verification bodies must refer to this document to ensure that the most current guidance is adhered to in project design and verification. Verification bodies shall refer to this document immediately prior to uploading any Verification Statement to assure all issues are properly addressed and incorporated into verification activities.

If you have any questions about the updates or clarifications in this document, please contact Policy at policy@climateactionreserve.org or (213) 891-1444 x3.

[1] See Section 4.3.4 of the Climate Action Reserve Program Manual for an explanation of the Reserve's policies on protocol errata and clarifications. "Errata" are issued to correct typographical errors. "Clarifications" are issued to ensure consistent interpretation and application of the protocol. For document management and program implementation purposes, both errata and clarifications are contained in this single document.

Errata and Clarifications (arranged by protocol section)

Section 5

1. Accounting for Additional Non-Methane Cooling Air Volume in VAM Oxidation Projects (CLARIFICATION – October 22, 2013)

Section: 5.2.2, Equation 5.10

Context: Due to the high temperatures which may result from high methane concentrations of VAM entering destruction devices at a project, additional non-methane fresh air (either occasionally or continuous) may be added to the system to prevent overheating of the destruction device. The protocol assumes a closed system, in which the flow rate of the input and exhaust are the same. However, in the case of destruction devices in which additional non-methane fresh air is added after the point at which VAM input flow is metered, the flow of the exhaust would be greater than the metered flow of the input. Without accounting for this additional flow, the methane destruction will be overestimated due to the dilution of methane in the exhaust gas. It is not clear how projects should account for this situation in the quantification methodology.

Clarification: Destruction devices requiring an additional cooling air intake component are permissible under this protocol. To account for the additional non-methane air, Equation 5.10 shall be replaced with the revised Equation 5.10 below. If destruction devices include a cooling air intake, the flow of additional non-methane air entering the destruction device should be metered and the actual flow data shall be used in the equation. However, if the cooling air intake is not metered, the project developer must instead use the maximum flow rate (e.g. the full capacity) of the cooling air intake system for the full duration of time when it is operating. If the operational status of the cooling air system is not monitored, the project developer shall assume that the system is always operational.

Revised Equation 5.10. CH_4 Destroyed by VAM Oxidation

$$\boldsymbol{MD_{OX} = MM_{OX} - PE_{OX}}$$

Where, Units

MD_{OX}	=	Methane destroyed through oxidation during the reporting period	tCH_4
MM_{OX}	=	Methane measured sent to oxidizer during the reporting period	tCH_4
PE_{OX}	=	Project emissions of non-oxidized CH_4 from oxidation of the VAM stream during the reporting period	tCH_4

And,

$$\boldsymbol{MM_{OX} = VAM_{flow\,rate,y} \times time_y \times PC_{CH_4\,VAM} \times D_{CH_4}}$$

Where, Units

$VAM_{flow\ rate,y}$	=	Average flow rate of ventilation air entering the oxidation unit during period y corrected if needed for inlet flow gas pressure and temperature ($P_{VAM\ inflow}$ and $T_{VAM\ inflow}$ respectively) per Equation 5.12	scfm
$time_y$	=	Time during which VAM unit is operational during period y	m
$PC_{CH4\ VAM}$	=	Concentration of methane in the ventilation air entering the oxidation unit, corrected if needed for pressure and temperature in the vicinity of the methane analyzer	scf/scf
D_{CH4}	=	Density of methane under standard conditions	tCH_4/scf

And,

$$PE_{OX} = VAM_{exhaust\ volume,y} \times PC_{CH_4\ exhaust} \times D_{CH_4}$$

Where, Units

$VAM_{exhaust\ volume,y}$	=	Total volume of methane leaving the oxidation unit during period y	scf
$PC_{CH4\ exhaust}$	=	Concentration of methane in the ventilation air exhaust, corrected if needed for pressure and temperature in the vicinity of the methane analyzer ($P_{VAM\ analyzer\ inflow}$, $T_{VAM\ analyzer\ inflow}$, $P_{VAM\ analyzer\ exhaust}$, and $T_{VAM\ analyzer\ exhaust}$)	scf/scf
D_{CH4}	=	Density of methane under standard conditions	tCH_4/scf

And either,

$$VAM_{exhaust\ volume,y} = VAM_{exhaust\ flow\ rate,y} \times time_y$$

Or,

$$VAM_{exhaust\ volume,y} = \left(VAM_{flow\ rate,y} \times time_y\right) + \left(CA_{flow\ rate,z} \times time_z\right)$$

Where, Units

$VAM_{exhaust\ flow\ rate,y}$	=	Average metered flow rate of the ventilation air exhaust leaving the oxidation unit during period y, corrected if needed for inlet flow gas pressure and temperature ($P_{VAM\ inflow}$ and $T_{VAM\ inflow}$ respectively) per Equation 5.12	scfm
$CA_{flow\ rate,z}$	=	Flow rate[a] of additional cooling air added to VAM destruction system after metering point for $VAM_{flow\ rate}$ (equal to zero, if the project is a closed system in which VAM intake flow is equal to exhaust gas flow)	scfm
$time_z$	=	Subset of time, z, during which the air intake system is operational within the time period y[b]	m

[a] If the project is metering the cooling air intake flow volume, then the average metered data flow rate shall be used. If the flow is not metered, then the maximum capacity of the air intake system shall be used for the flow rate.

[b] If the operational status of the air intake system is not monitored, then the system shall be assumed to be operational at all times (i.e. $time_y = time_z$).

Section 6

2. NMHC Sampling Requirements (CLARIFICATION – March 10, 2014)

Section: 6.1

Context: The protocol requires the non-methane hydrocarbon (NMHC) content of coal mine gas (CMG) to be determined on an annual basis by a full gas analysis using a gas chromatograph for both VAM projects and drainage projects. The protocol goes on to state that these gas samples shall be collected “prior to each destruction device.” While the protocol’s intent is that the NMHC gas sample be taken upstream of each destruction device, it is not necessary to take multiple NMHC samples of CMG from a single drainage system or ventilation shaft if multiple destruction devices are being used. Rather, the protocol’s intent is to require that a separate NMHC sample be taken upstream of the destruction device for each CMG source within the project definition.

Clarification: The last sentence in the relevant paragraph shall be replaced with:

"Separate gas samples shall be collected from each drainage system or ventilation shaft within the project definition by a third-party technician. The sample shall be taken upstream of the destruction device(s)."

CLIMATE ACTION RESERVE

Version 1.1 | October 26, 2012

Coal Mine Methane

Project Protocol

Climate Action Reserve
601 West 5th Street, Suite 650
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Released October 26, 2012

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Abbreviations and Acronyms

ACM	Approved consolidated baseline and monitoring methodology under CDM
CAA	Clean Air Act
CDM	Clean Development Mechanism
CH_4	Methane
CMG	Coal mine gas
CMM	Coal mine methane
CNG	Compressed natural gas
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
CRT	Climate Reserve Tonne
EIA	Energy Information Administration
GHG	Greenhouse gas
HMM	Coal mine methane from horizontal pre-mining
ISO	International Organization for Standardization
IPCC	Intergovernmental Panel on Climate Change
LNG	Liquid natural gas
MSHA	Mine Safety and Health Administration
NMHC	Non-methane hydrocarbon
NOV	Notice of Violation
NOVA/COI	Notification of Verification Activities/Conflict of Interest
PMM	Coal mine methane from post-mining (gob wells)
QA/QC	Quality assurance/quality control
SMM	Coal mine methane from surface pre-mining
SSR	Sources, sinks and reservoirs
UNFCCC	United Nations Framework Convention on Climate Change
U.S. EPA	United States Environmental Protection Agency
VAM	Ventilation air methane
WBCSD	World Business Council for Sustainable Development
WRI	World Resources Institute

1 Introduction

The Climate Action Reserve (Reserve) Coal Mine Methane Project Protocol provides guidance to account for, report and verify greenhouse gas (GHG) emission reductions associated with destroying methane from active underground coal mines that would have otherwise been vented to the atmosphere from degasification systems, including drainage systems and ventilation systems. The protocol focuses on quantifying the change in methane emissions, but also accounts for effects on carbon dioxide emissions.

As the premier carbon offset registry for the North American carbon market, the Climate Action Reserve works to ensure environmental benefit, integrity, and transparency in market-based solutions that reduce GHG emissions. It establishes high quality standards for carbon offset projects, oversees independent third-party verification bodies, issues carbon credits generated from such projects and tracks the transaction of credits over time in a transparent, publicly-accessible system. By facilitating and encouraging the creation of GHG emission reduction projects, the Climate Action Reserve program promotes immediate environmental and health benefits to local communities, allows project developers access to additional revenues and brings credibility and value to the carbon market. The Climate Action Reserve is a private 501c(3) nonprofit organization based in Los Angeles, California.

Project developers that install coal mine methane destruction technologies use this document to register GHG reductions with the Reserve. The protocol provides eligibility rules, methods to calculate reductions, performance-monitoring instructions, and procedures for reporting project information to the Reserve. Additionally, all project reports receive independent verification by ISO-accredited and Reserve-approved verification bodies. Guidance for verification bodies to verify reductions is provided in the Reserve's Verification Program Manual and Section 8 of this protocol.

This protocol is designed to ensure the complete, consistent, transparent, accurate, and conservative quantification and verification of GHG emission reductions associated with a coal mine methane project.[1]

[1] See the WRI/WBCSD GHG Protocol for Project Accounting (Part I, Chapter 4) for a description of GHG reduction project accounting principles.

2 The GHG Reduction Project

2.1 Background

Methane is formed during the same geologic process that converts vegetative matter to coal; coal mining and post-mining processes release this methane from the coal and surrounding rock to the atmosphere. The amount of methane contained in and around a coal seam tends to be correlated with the amount of geologic pressure on the seam, which in turn depends on the seam depth.

When combined with air in concentrations of 5 to 15 percent, methane released by mining activity is explosive within the mine atmosphere. All underground coal mines in the United States are required to establish and maintain ventilation systems meeting detailed specifications set forth in federal regulations; these regulations are enforced by the Mine Safety and Health Administration (MSHA). Under the MSHA regulations, methane concentrations must be kept below 1 percent at the working face. Degasification is therefore an integral and critically important component of the underground mining process. Two primary degasification techniques are available to the operator: ventilation and methane drainage. Methane emissions are vented through mine ventilation shafts or methane drainage wells designed for the express purpose of removing the methane from the mine and venting it to the atmosphere.

Ventilation

The primary purpose of ventilation systems is to (1) dilute the methane in the mine air, and (2) remove the methane from the mine. Clean intake air is drawn into the mine from above ground through intake air shafts and/or horizontal drift entries, where it is channeled through the intake airways to the face, and then through the “returns” to a return air shaft(s) and/or drift entry(ies). The energy needed to move the large quantities of air required under the MSHA regulations through the ventilation system is provided by high-powered exhaust mine fans located on the surface at the return air shaft(s). Upon passing up the return air shaft(s) and through the fan, the mine air, including diluted methane, is vented to the atmosphere.

The ventilation systems emit highly dilute concentrations of the methane; typically the mine air vented from return air shafts is less than 1 percent methane. In this protocol, coal mine methane in mine air emitted through ventilation systems is referred to as ventilation air methane or “VAM.”

Methane Drainage

At very gassy mines, ventilation is typically supplemented with methane drainage systems designed to remove methane either in advance of, or behind, the working face. These systems involve drilling boreholes, either from the surface or inside the mine, to drain methane from the coal seam, surrounding strata, or underground workings, thereby reducing the amount of methane that has to be handled by the ventilation system.

There are three main types of drainage systems, which may be employed in isolation or in combination with one another:

- Surface pre-mining boreholes
- Horizontal pre-mining boreholes
- Post-mining (or gob) boreholes

Each of these three system types are described in more detail below. Note that the protocol distinguishes between *coal mine gas* (CMG), which is the gas that comes out of the boreholes before any processing or enrichment and often contains various levels of other compounds (e.g. nitrogen, oxygen, carbon dioxide, hydrogen sulfide, NMHC, etc.) and *coal mine methane* (CMM), which represents only the methane portion of CMG.

Surface Pre-Mining Boreholes

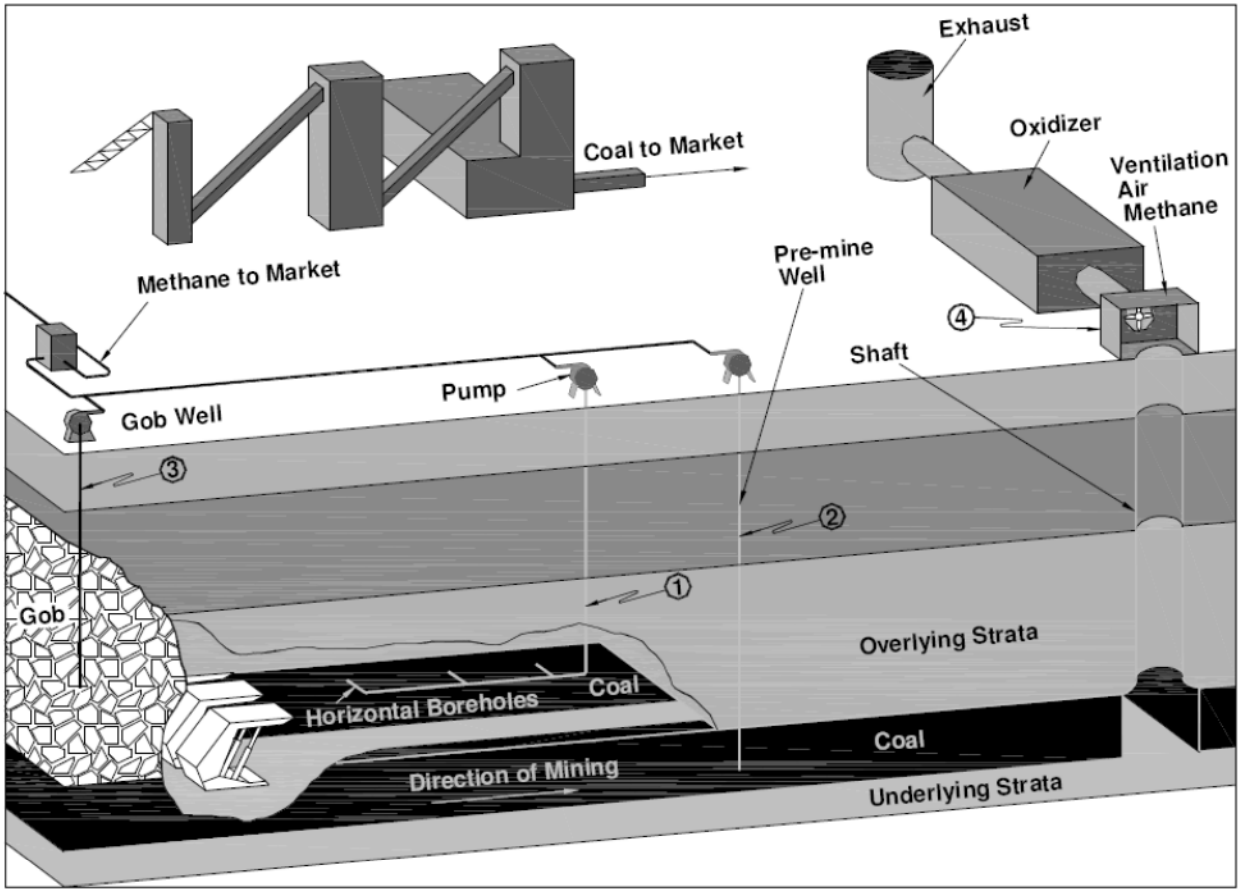
Surface pre-mining boreholes, or wells, are drilled from the surface to unmined portions of the coal seam in advance of mining (see Figure 2.1). They may be vertical, vertical to lateral, or even close to horizontal in their orientation. Surface-to-seam boreholes (otherwise known as surface-drilled directional boreholes) fall into this category. All of these surface pre-mining boreholes collect methane both from the seam itself, as well as from strata lying above the seam. Surface pre-mining wells may be drilled in locations that are not scheduled to be mined through for months or years; sometimes surface pre-mining wells are drilled before the associated mine even opens. Because they are drilled into virgin coal instead of the underground workings, pre-mining surface wells produce a high quality gas that is uncontaminated with mine air. Typically gas from these wells is at least 90 percent pure methane. In this protocol, the acronym “SMM” refers to coal mine methane drained from surface pre-mining boreholes.

Horizontal Pre-Mining Boreholes

Horizontal pre-mining boreholes, also referred to as “in-mine” boreholes, are drilled from within the mine (rather than from the surface) into unmined blocks of coal (see Figure 2.1). They are generally 400 to 800 feet in length, and are drilled shortly (as opposed to years) before mining occurs. Methane is drained from the boreholes by an in-mine vacuum piping system, which transports the methane to the surface where it may be either vented or captured and utilized. Because horizontal boreholes are drilled directly into the coal seam from the mine, drainage is limited to the methane contained within the seam; methane in the surrounding strata is unaffected. Hence recovery rates tend to be low (10 to 18 percent of the methane that would otherwise have been emitted from the ventilation system), although the gas recovered from horizontal boreholes is generally comparable in purity to methane drained from surface pre-mining boreholes. In this protocol, the acronym “HMM” refers to coal mine methane from horizontal pre-mining boreholes.

Post-Mining Boreholes

Post-mining, or gob, boreholes are drilled from the surface to a point 10 to 50 feet above the coal seam in advance of mining (see Figure 2.1). As mining advances under and past the well, the strata above the coal seam fractures and eventually collapses into the mined out area creating a de-pressurized zone extending up to the well; this zone is called the gob. Methane and other gases from the gob are collected via the gob well. The gob is exposed to the mine air, and hence the methane drained by gob wells is typically less pure than gas recovered by pre-mining boreholes, although it can be high quality early on in the life of the well. In many cases vacuum pumps are used in conjunction with gob wells to enhance gas recovery and to prevent methane from entering the mine’s ventilation circuit. However, these pumps may draw in mine air as well as methane, thus exacerbating the contamination of the recovered methane. Gob gas typically has a heating value ranging from 300 to 800 Btus per cubic feet (as compared with approximately 1,000 Btus per cubic foot for pipeline quality natural gas). In this protocol, the acronym “PMM” refers to coal mine methane from post-mining boreholes.



1) Horizontal Pre-Mining 2) Surface Pre-Mining 3) Post-Mining and 4) VAM
Source: U.S. EPA *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002 – 2006*, EPA -430-K-04-003, January 2009, p 2-5.

Figure 2.1. Schematic of Degasification Types

2.2 Project Definition

For the purpose of this protocol, a GHG reduction project (project) is defined as the installation and operation of any device, or set of devices, that result in the destruction of methane gas that would otherwise have been vented to the atmosphere from an active underground mine. Eligible mines include coal mines as well as trona mines that are classified by MSHA as Category III gassy underground metal and non-metal mines. While the protocol document refers to “coal mine methane” throughout, it may be applied to methane released through mining at Category III gassy underground trona mines.

A project must consist of either:

1. Installation and operation of a methane destruction device (or multiple devices) that destroys methane from a methane drainage system
2. Installation and operation of a methane destruction device (or multiple devices) that destroys ventilation air methane

A single project may not combine destruction of both drainage system and ventilation air methane, except under limited circumstances.[2] However, both drainage projects and VAM projects may be implemented and registered separately at the same mine. In addition, project developers may register multiple projects of the same type at the same mine, e.g. if separate destruction devices are installed at different times.

The protocol does not apply to projects that:

- Operate in surface mines
- Destroy methane from abandoned mines
- Destroy virgin coal bed methane (e.g. methane of high quality extracted from coal seams independently of any mining activities)
- Use CO_2 or any other fluid/gas to enhance CMM drainage before mining takes place

Under the terms of this protocol, the Reserve will issue CRTs only for the destruction of methane that would otherwise have been emitted to the atmosphere. Some projects may put captured CMM to beneficial use by using it to generate energy. Projects that use CMM for energy production are eligible under this protocol (since they destroy methane in the process). However, such projects will not receive credit for displacing GHG emissions associated with other fossil fuels that might have been used to produce energy. Although the Reserve does not issue CRTs for fossil fuel displacement, it strongly supports using CMM for energy production.

2.2.1 Drainage Projects

A drainage project is one that destroys methane that would otherwise be vented to the atmosphere from a methane drainage system. The methane drainage system may use any of the following extraction activities:

- Surface boreholes, including vertical and surface-to-seam directional drilling, located within the boundary of the mine to capture pre-mining CMM
- In-mine underground horizontal boreholes located within the boundary of the mine to capture pre-mining CMM
- Surface gob wells, underground boreholes, gas drainage galleries or other gob gas capture techniques located within the boundary of the mine, including gas from sealed areas, to capture post mining CMM

The borehole(s) that make up each project's drainage system must be defined by the project developer at the time of project submittal. The project developer must also specify what destruction device(s) is/are part of the drainage project. A single project must be explicitly defined and associated with specific boreholes and destruction devices. Multiple drainage projects may be implemented at a single mine, each with its own start date, crediting period, registration, and verification cycle. Each project's drainage system and destruction devices shall be detailed in the project diagram.

If additional boreholes are drilled and/or connected to an existing qualifying project destruction device, this is considered a project expansion. Similarly, if a new or additional destruction device is added to boreholes that are already connected to an existing project destruction device, this is considered a project expansion. If a new borehole or a borehole that is currently venting CMM

[2] In some cases, CMM from a drainage system is allowed to supplement a VAM project (see Section 3.4.1.1). In this case, a single project can consist of both drainage system and VAM methane destruction, as long as the drainage system contribution is limited to supplemental CMM.

is connected to a new destruction device, this may be considered a new project or a project expansion. If the project developer chooses to define it as a project expansion, the project start date and crediting period remain the same as the original project, and a single verification will cover all activities. If the project developer chooses to define it as a new project, the project will have a new start date and crediting period, and the new project will require separate verification.

2.2.2 Ventilation Air Methane Projects

A ventilation air methane project is one that destroys methane that would otherwise be vented from a ventilation shaft (or multiple shafts). The ventilation shaft(s) and VAM destruction device(s) that make up each VAM project must be defined by the project developer at the time of project submittal. A single project must be explicitly defined and associated with a specific shaft (or multiple shafts that are operating concurrently). Multiple projects may be implemented at a single mine, each with its own start date, crediting period, registration, and verification cycle. Each project's ventilation shaft(s) and VAM destruction device(s) shall be detailed in the project diagram.

If additional VAM destruction equipment is added to a shaft that is part of an existing project, this is considered a project expansion. If VAM destruction equipment is installed at a shaft that is not part of an existing project, this new shaft may be considered a new project or a project expansion. If the project developer chooses to define it as a project expansion, the project start date and crediting period remain the same, and a single verification will cover activities at both shafts. If the project developer chooses to define it as a new project, activities at the new shaft will have a new start date and crediting period, and will require separate verification. For a new VAM project, the VAM destruction equipment does not need to be new; it is only the ventilation shaft that must be new.

2.2.3 Non-Qualifying Devices

Non-qualifying devices are devices that destroy CMM but do not meet one or more of the eligibility rules as described in Section 3 and are located at the same mine where eligible project activities are taking place.[3] If there are any non-qualifying devices in operation at a mine, the project developer must include the non-qualifying device(s) in the project's GHG Assessment Boundary (see Section 0) and in the project diagram (see Section 7.1). Subsequent projects implemented at the same mine may exclude the same non-qualifying device(s) from their GHG assessment boundaries. In other words, if methane destruction at a non-qualifying device is accounted for by one project at a mine, it does not need to be accounted for by other projects at the same mine.

If any new non-qualifying devices become operational at the mine, these devices must be assigned to a specific project. In the case where a project developer has more than one registered project at a mine, the project developer may choose which project will account for the new non-qualifying device.

In the case where there are multiple projects with different crediting periods at a mine, when the crediting period for a project that includes a non-qualifying device expires, the non-qualifying device must be added to the GHG Assessment Boundary of a project that is still active. Thus, all non-qualifying devices must be properly accounted for in the GHG Assessment Boundary of an active project at the mine over time.

[3] Coal mine methane sent off-site through a pipeline is not eligible, but is also outside of the GHG Assessment Boundary. Because CMM sent to a pipeline is outside of the GHG Assessment Boundary, sources of emissions associated with pipelines are not included in the project diagram.

2.3 The Project Developer

The "project developer" is an entity that has an active account on the Reserve, submits a project for listing and registration with the Reserve, and is ultimately responsible for all project reporting and verification. Project developers may be mine owners, mine operators, GHG project financiers, utilities, independent energy companies, or other entities. The project developer must have clear ownership of the project's GHG reductions. Ownership of the GHG reductions must be established by clear and explicit title, and the project developer must attest to such ownership by signing the Reserve's Attestation of Title form.[4]

Under this protocol, the project developer is the only party required to be involved with project implementation.

[4] Attestation of Title form available at http://www.climateactionreserve.org/how/program/documents/.

3 Eligibility Rules

Projects that meet the definition of a GHG reduction project in Section 2.2 must fully satisfy the following eligibility rules in order to register with the Reserve.

Eligibility Rule I:	Location	⟶	*U.S. and its territories*
Eligibility Rule II:	Project Start Date	⟶	*No more than six months prior to project submission*
Eligibility Rule III:	Additionality	⟶	*Exceed legal requirements*
		⟶	*Meet performance standard*
Eligibility Rule IV:	Regulatory Compliance	⟶	*Compliance with all applicable laws*

3.1 Location

Under this protocol, only projects located at a single mine in the United States and its territories are eligible to register with the Reserve.[5]

3.2 Project Start Date

The project start date shall be defined by the project developer, but must be no more than three months after coal mine methane is first destroyed by the project, regardless of whether sufficient monitoring data is available to report reductions. The start date is defined in relation to the commencement of methane destruction, not other activities that may be associated with project initiation or development. For projects that involve pre-mine drainage, for example, well-drilling may commence in advance of any methane destruction; in such cases, the start date would be linked to the commencement of methane destruction, not drilling activities.

To be eligible, the project must be submitted to the Reserve no more than six months after the project start date.[6] Projects may always be submitted for listing by the Reserve prior to their start date.

3.3 Project Crediting Period

The crediting period for coal mine methane projects under this protocol is ten years. At the end of a project's first crediting period, a project developer may apply for eligibility under a second crediting period. However, the Reserve will cease to issue CRTs for GHG reductions if at any point in the future CMM destruction becomes legally required at the project site. Thus, the Reserve will issue CRTs for GHG reductions quantified and verified according to this protocol for a maximum of two ten year crediting periods after the project start date, or until the project activity is required by law, whichever comes first. Section 3.4.1 defines the conditions under which a project is considered legally required, and Section 3.4.1.1 describes the requirements to qualify for a second crediting period. If a project developer wishes to apply for eligibility under a

[5] The Reserve anticipates that this protocol could be applied throughout North America and internationally. To expand its applicability, data and analysis supporting an appropriate performance standard for other countries would have to be conducted accordingly. Refer to Appendix A for information on the performance standard analysis supporting application of this protocol in the United States.

[6] Projects are considered submitted when the project developer has fully completed and filed the appropriate project submittal documentation, available on the Reserve's website.

second crediting period, they must do so within the final six months of the initial crediting period. Deadlines and requirements for reporting and verification, as laid out in this protocol and the Verification Program Manual, will continue to apply without interruption.

The crediting period will also end if the mine where a project is located is declared abandoned; the Reserve will issue CRTs for GHG reductions quantified and verified according to this protocol only up until the date the mine was declared abandoned (i.e. the date when ventilation is discontinued).

3.4 Additionality

The Reserve strives to register only projects that yield surplus GHG reductions that are additional to what would have occurred in the absence of a carbon offset market.

Projects must satisfy the following tests to be considered additional:

1. The Legal Requirement Test
2. The Performance Standard Test

3.4.1 The Legal Requirement Test

All projects are subject to a Legal Requirement Test to ensure that the GHG reductions achieved by a project would not otherwise have occurred due to federal, state, or local regulations, or other legally binding mandates. A project passes the Legal Requirement Test when there are no laws, statutes, regulations, court orders, environmental mitigation agreements, permitting conditions, or other legally binding mandates requiring the destruction of coal mine methane at the project site. To satisfy the Legal Requirement Test, project developers must submit a signed Attestation of Voluntary Implementation form[7] prior to the commencement of verification activities each time the project is verified (see Section 8). In addition, the project's Monitoring Plan (Section 6) must include procedures that the project developer will follow to ascertain and demonstrate that the project at all times passes the Legal Requirement Test.

The Reserve did not identify any existing federal, state or local regulations that obligate mines to destroy coal mine methane.[8] If an eligible project begins operation at a mine that later becomes subject to a regulation, ordinance or permitting condition that calls for the destruction of coal mine methane, emission reductions may be reported to the Reserve up until the date that the coal mine methane is legally required to be destroyed. If the mine's methane emissions are included under an emissions cap (e.g. under a state or federal cap-and-trade program), emission reductions may likewise be reported to the Reserve until the date that the emissions cap takes effect.

[7] Attestation of Voluntary Implementation form available at http://www.climateactionreserve.org/how/program/documents/.

[8] To ensure that methane remains well below the concentrations at which it becomes explosive, the Federal Coal Mine Health and Safety Act of 1969 requires that methane levels be kept below 1 percent at the working face of the mine. To ensure that this requirement is met, all underground mines (gassy and non-gassy) are required under the same Act to develop ventilation systems that meet detailed specifications laid out in the federal regulations. The methane concentration limits and ventilation requirements are enforced by MSHA. The Act does not require, however, that CMM be destroyed.

3.4.1.1 U.S. EPA GHG Permitting Requirements under the Clean Air Act

Since January 2, 2011, the United States Environmental Protection Agency (U.S. EPA) has been phasing in[9] regulation of GHG emissions from major stationary sources under the Clean Air Act (CAA).[10]

Under this rule, commonly referred to as the "Tailoring Rule," all existing stationary sources emitting more than 100,000 tons (approximately 90,719 MT) of CO_2e emissions per year are required to obtain Title V operating permits for GHG emissions. Historically, underground mines have not been a source category subject to Title V operating permits. However, the Tailoring Rule also requires Prevention of Significant Deterioration (PSD) permits that address GHG emissions for (1) new source construction with emissions of 100,000 tons CO_2e per year or more and (2) major facility modifications resulting in GHG emission increases of 75,000 tons (approximately 68,000 MT) of CO_2e per year or more.[11] An assessment of "best available control technology" (BACT) for GHGs is required as part of the PSD permitting process; the permitting authority will ultimately mandate installation of a selected BACT. It is possible that future PSD permits may require installation of the same abatement technologies that are currently being voluntarily deployed as part of a carbon offset project at a mine. By legally mandating these technologies, PSD permit requirements may make them ineligible for carbon offsets because implementation of these projects would no longer be voluntary.

According to the Reserve's understanding of the EPA Tailoring Rule requirements, new mines or mines that undertake significant expansion may be subject to the new PSD requirements. If a mine triggers the PSD requirements and an official BACT review results in the mandatory installation of a technology that reduces CMM emissions, this activity will not be eligible for carbon offsets. Verification bodies will need to review these permits to ensure that projects are able to pass the Legal Requirement Test.

The Reserve continues to track these developments under the CAA. BACT determinations made at the state level will inform updates to the protocol's tests for additionality over time.

3.4.2 The Performance Standard Test

Projects pass the Performance Standard Test by meeting a performance threshold, i.e. a standard of performance applicable to all coal mine methane destruction projects, established on an ex-ante basis by this protocol.

There are numerous possible management options and end uses for coal mine methane, ranging from venting, to destruction by flares, to injection of the methane into natural gas pipelines. The Performance Standard Test employed by this protocol is based on a national

[9] All major sources already subject to PSD and/or Title V under the Clean Air Act for other pollutants have been subject to EPA's GHG permitting rules since January 2, 2011. All sources *not* previously subject to the Clean Air Act came under the GHG permitting rules on July 1, 2011, if they triggered the thresholds noted herein.

[10] U.S. EPA published the final rulemaking, "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Final Rule," in the Federal Register on June 3, 2010. The rulemaking is commonly referred to as the "Tailoring Rule," and amended 40 CFR Parts 51, 52, 70, and 71. http://www.gpo.gov/fdsys/pkg/FR-2010-06-03/pdf/2010-11974.pdf#page=1. In the final rulemaking in June 2010, the EPA also committed to undertake another rulemaking to conclude no later than July 1, 2012, which would phase in GHG permitting for smaller sources. However, in July 2012, EPA issued another rulemaking for the Tailoring Rule which continues to focus GHG permitting on the largest emitters, deferring GHG permitting for smaller sources to a later date. http://www.gpo.gov/fdsys/pkg/FR-2012-07-12/pdf/2012-16704.pdf

[11] "PSD and Title V Permitting Guidance for Greenhouse Gases" available at http://www.epa.gov/nsr/ghgdocs/epa-hq-oar-2010-0841-0001.pdf.

assessment of "common practice" for managing coal mine methane. The performance standard defines those end uses that the Reserve has determined will exceed common practice and therefore generates additional GHG reductions.[12]

Drainage projects pass the Performance Standard Test if they destroy CMM through any end-use management option other than injection into a natural gas pipeline for off-site consumption (e.g. flare, power generation, heat generation, producing CNG/LNG for vehicle use, etc.).

All VAM projects pass the Performance Standard Test. Such projects may include, but are not limited to, the following end uses for VAM:

- Thermal flow reversal reactors with or without catalysts
- Volatile organic compound concentrators
- Carbureted gas turbines
- Lean-fueled turbines with catalytic combustors that compress the air/methane mixture and then combust it in a catalytic combustor
- Hybrid coal- and ventilation air-fueled gas turbine technology
- Lean-fueled catalytic microturbine technology
- Combustion air for commercial engine and turbine technologies or a coal-fired steam power plant

In some cases, VAM projects may need to supplement VAM with CMM from drainage boreholes, either to increase the concentration of methane flowing into the combustion/oxidation device or to help balance the concentration of methane flowing into the combustion/oxidation device. This supplemental CMM is also eligible as part of a VAM project, as long as the supplemental CMM would not have been used for energy purposes.

The Performance Standard Test is applied at the time a project applies for registration with the Reserve. Once a project is registered, it does not need to be evaluated against future versions of the protocol or the Performance Standard Test for the duration of its first crediting period.

If a project developer wishes to apply for a second crediting period, the project must meet the requirements of the most current version of this protocol, including any updates to the Performance Standard Test.

3.5 Regulatory Compliance

As a final eligibility requirement, project developers must attest that project activities do not cause material violations of applicable laws (e.g. air, water quality, safety, etc.). To satisfy this requirement, project developers must submit a signed Attestation of Regulatory Compliance form prior to the commencement of verification activities each time the project is verified.[13] Project developers are also required to disclose in writing to the verifier any and all instances of legal violations – material or otherwise – caused by the project or project activities.

A violation should be considered to be "caused" by project activities if it can be reasonably argued that the violation would not have occurred in the absence of the project activities. If there is any question of causality, the project developer shall disclose the violation to the verifier.

[12] A summary of the study and analysis used to establish the Performance Standard Test is provided in Appendix A.
[13] Attestation of Regulatory Compliance form available at http://www.climateactionreserve.org/how/program/documents/.

If a verifier finds that project activities have caused a material violation, then CRTs will not be issued for GHG reductions that occurred during the period(s) when the violation occurred. Individual violations due to administrative or reporting issues, or due to “acts of nature,” are not considered material and will not affect CRT crediting. However, recurrent administrative violations directly related to project activities may affect crediting. Verifiers must determine if recurrent violations rise to the level of materiality. If the verifier is unable to assess the materiality of the violation, then the verifier shall consult with the Reserve.

4 GHG Assessment Boundary

The GHG Assessment Boundary delineates the GHG sources, sinks, and reservoirs (SSRs) that shall be assessed by project developers in order to determine the total net change in GHG emissions caused by a coal mine methane project.

This protocol does not account for carbon dioxide emission reductions associated with displacing grid-delivered electricity or fossil fuel use.

Figure 4.1 provides a general illustration of the GHG Assessment Boundary for VAM projects, indicating which SSRs are included or excluded from the boundary.

Figure 4.2 provides a general illustration of the GHG Assessment Boundary for drainage projects, indicating which SSRs are included or excluded from the boundary.

Table 4.1 provides greater detail on each SSR and provides justification for all SSRs and gases that are excluded from the GHG Assessment Boundary. The GHG Assessment Boundary diagram and table presented here apply to both drainage and VAM projects; individual SSRs may or may not be relevant depending on the project type.

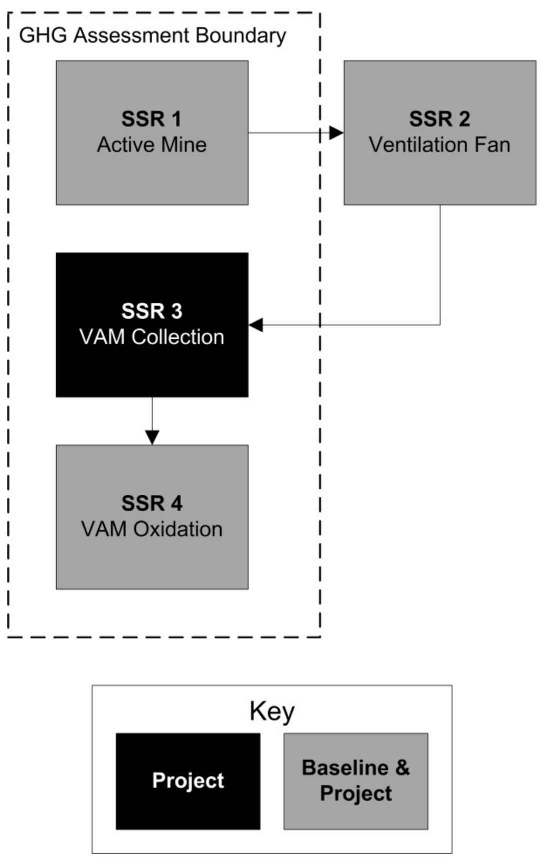


Figure 4.1. Illustration of the GHG Assessment Boundary for VAM Projects

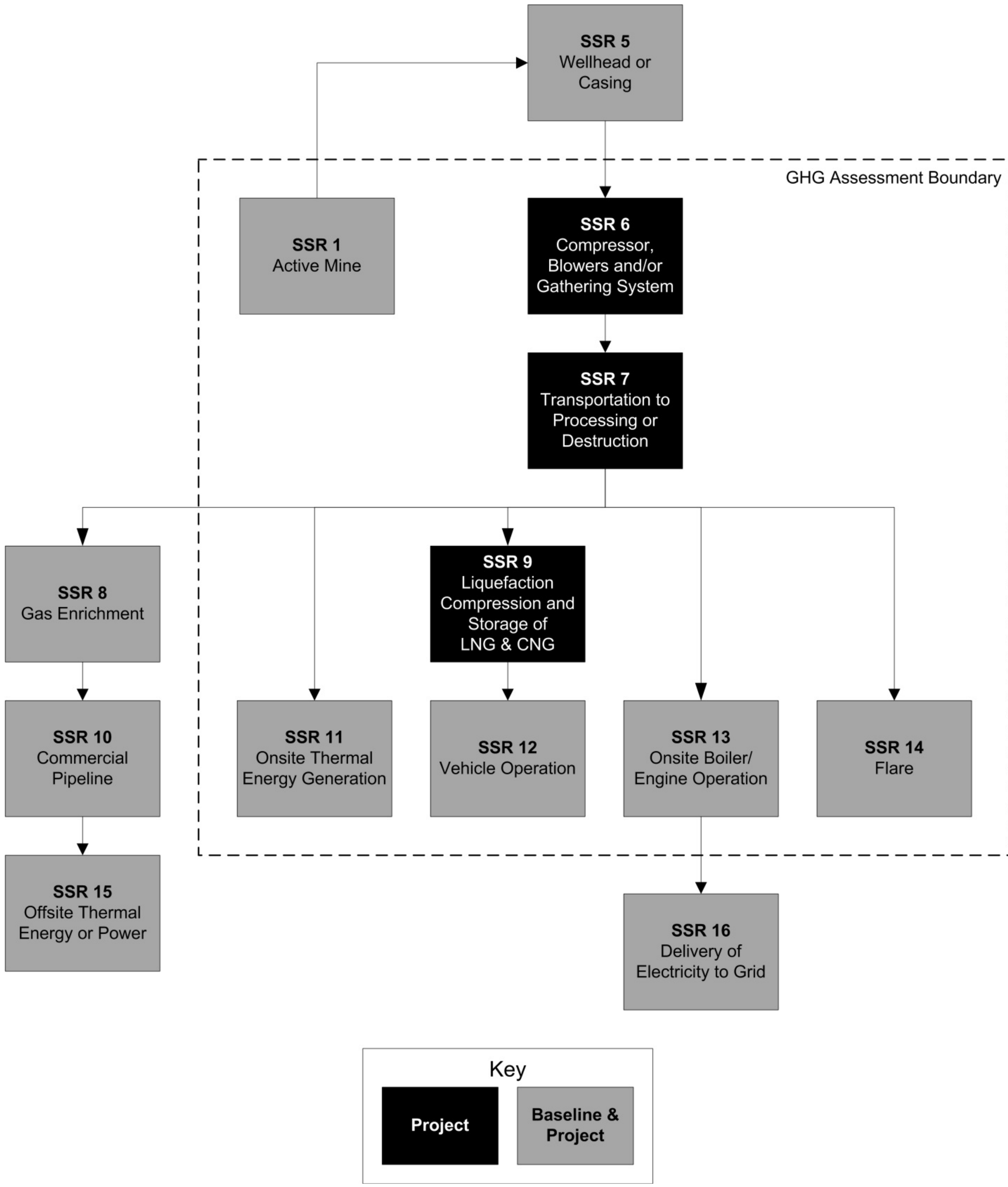


Figure 4.2. Illustration of the GHG Assessment Boundary for Drainage Projects

Table 4.1. Summary of Identified Sources, Sinks, and Reservoirs

SSR	Source	Gas	Relevant to Baseline (B) or Project (P)	Included/ Excluded	Justification/Explanation
1	Active mine – emissions as a result of venting	CH_4	B, P	Included	Main emission source of methane from active mines. A GHG project will directly affect these emissions. Only the change in CMM emissions release will be taken into account, by monitoring the methane used or destroyed by the project.
2	Ventilation fan	CO_2	n/a	Excluded	Ventilation fan operation will not be affected by the project.
3	VAM collection system	CO_2	P	Included	The VAM collection system will result in increased combustion emissions due to energy consumption from equipment used to drain, compress, blow, and gather VAM.
		CH_4		Excluded	Excluded for simplification. This emission source is assumed to be very small.
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
4	VAM oxidation	CO_2	B, P	Included	VAM project will result in increased CO_2 emissions from the oxidation of methane in ventilation air.
		CH_4	P	Included	VAM project will result in CH_4 emissions from non-oxidized CH_4 from the ventilation air stream.
		N_2O	n/a	Excluded	Excluded for simplification. This emission source is assumed to be very small.
	Emissions from NMHC destruction	CO_2	P	Included if >3,500 mg/m^3	VAM project will result in increased CO_2 emissions from the combustion of NMHC in oxidizer (only included if NMHC accounts for more than 3,500 mg/m^3 (wet basis) of extracted ventilation air).
5	Fugitive emissions resulting from casing or wellhead	CH_4	n/a	Excluded	The project is unlikely to affect quantities of methane from this source.
6	Emissions resulting from energy used by compressors, blowers, and/or gathering system	CO_2	P	Included	If any additional equipment is required by the project beyond what is required in the baseline, energy consumption from additional equipment shall be accounted for. Energy used by equipment installed for the safety of the mine shall be excluded.
		CH_4		Excluded	Excluded for simplification. This emission source is assumed to be very small.
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
	Fugitive emissions resulting from compressors, blowers, and/or gathering system	CH_4	n/a	Excluded	Excluded for simplification. This emission source is assumed to be very small.
7	Fuel consumption for transport of CMG to processing or destruction equipment	CO_2	P	Included	If any additional equipment is required by the project beyond what is required in the baseline, energy consumption from additional equipment shall be accounted for.
		CH_4		Excluded	Excluded for simplification. This emission source is assumed to be very small.
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
	Fugitive emissions from transport of CMG to processing or destruction equipment	CH_4	n/a	Excluded	Excluded for simplification. This emission source is assumed to be very small.
8	Emissions resulting from gas enrichment	CO_2	n/a	Excluded	The project is unlikely to affect quantities of methane sent to gas enrichment systems, and will
		CH_4		Excluded	

SSR	Source	Gas	Relevant to Baseline (B) or Project (P)	Included/ Excluded	Justification/Explanation
	system	N_2O		Excluded	therefore not affect energy consumption or fugitive emissions from gas enrichment systems.
9	Emissions resulting from liquefaction, compression, or storage of methane for vehicle fuel	CO_2	P	Included	If any additional equipment is required by the project beyond what is required in the baseline, energy consumption from additional equipment shall be accounted for.
		CH_4		Excluded	Excluded for simplification. This emission source is assumed to be very small.
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
10	Fugitive emissions from commercial pipelines	CH_4	n/a	Excluded	The project is unlikely to affect quantities of methane delivered to commercial pipelines, and will therefore not affect fugitive pipeline emissions.
11	Emissions resulting from combustion during on-site thermal energy generation	CO_2	B, P	Included	If CMM is used for on-site thermal energy generation, project will result in increased CO_2 emissions from the destruction of methane to generate energy. This source is also included where CMM is sent to a non-qualifying device to generate energy.
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
	Emissions resulting from incomplete combustion during onsite thermal energy generation	CH_4	P	Included	If CMM is used for on-site thermal energy generation, project will result in increased CH_4 emissions from incomplete combustion. This source is also included where CMM is sent to a non-qualifying device to generate energy.
	Emissions from NMHC destruction	CO_2	P	Included if >35,000 mg/m^3	If CMM is used for on-site thermal energy generation, project will result in increased CO_2 emissions from the combustion of NMHC during energy generation (only included if NMHC accounts for more than 35,000 mg/m^3 of CMG). This source is also included where CMM is sent to a non-qualifying device to generate energy.
12	Emissions resulting from combustion during vehicle operation	CO_2	B, P	Included	If CMM is used to produce CNG/LNG to fuel vehicle operation, project will result in increased CO_2 emissions from the destruction of methane in CNG/LNG vehicles. This source is also included where CMM is used for non-qualifying vehicle operation.
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
	Emissions resulting from incomplete combustion during vehicle operation	CH_4	P	Included	If CMM is used to produce CNG/LNG to fuel vehicle operation, project will result in increased CH_4 emissions from incomplete combustion. This source is also included where CMM is used for non-qualifying vehicle operation.
	Emissions from NMHC destruction	CO_2	P	Included if >35,000 mg/m^3	If CMM is to produce CNG/LNG to fuel vehicle operation, project will result in increased CO_2 emissions from the combustion of NMHC during vehicle operation (only included if NMHC accounts for more than 35,000 mg/m^3 of CMG). This source is also included where CMM is used for non-qualifying vehicle operation.
13	Emissions resulting from combustion during on-site electricity generation	CO_2	B, P	Included	If CMM is used for on-site power generation, project will result in increased CO_2 emissions from the destruction of methane to generate power. This source is also included where CMM is sent to a non-qualifying device for electricity generation.

SSR	Source	Gas	Relevant to Baseline (B) or Project (P)	Included/ Excluded	Justification/Explanation
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
	Emissions resulting from incomplete combustion during on-site electricity generation	CH_4	P	Included	If CMM is used for on-site power generation, project will result in increased CH_4 emissions from incomplete combustion. This source is also included where CMM is sent to a non-qualifying device for electricity generation.
	Emissions from NMHC destruction	CO_2	P	Included if >35,000 mg/m^3	If CMM is used for on-site power generation, project will result in increased CO_2 emissions from the combustion of NMHC during power generation (only included if NMHC accounts for more than 35,000 mg/m^3 of CMG). This source is also included where CMM is sent to a non-qualifying device for electricity generation.
14	Emissions resulting from combustion during flaring	CO_2	B, P	Included	If CMM is sent to a flare, project will result in increased CO_2 emissions from the destruction of methane in flare. This source is also included where CMM is sent to a non-qualifying device for flaring.
		N_2O		Excluded	Excluded for simplification. This emission source is assumed to be very small.
	Emissions resulting from incomplete combustion during flaring	CH_4	P	Included	If CMM is sent to a flare, project will result in increased CH_4 emissions from incomplete combustion. This source is also included where CMM is sent to a non-qualifying device for flaring.
	Emissions from NMHC destruction	CO_2	P	Included if >35,000 mg/m^3	If CMM is sent to a flare, project will result in increased CO_2 emissions from the combustion of NMHC in flare (only included if NMHC accounts for more than 35,000 mg/m^3 of CMG).
15	Emissions resulting from offsite thermal or power generation	CO_2	n/a	Excluded	The project is unlikely to affect quantities of methane delivered through pipelines to offsite thermal or power generation equipment, and will therefore not affect emissions from such equipment.
		N_2O			
	Emissions resulting from incomplete combustion during off-site thermal energy or power generation	CH_4			
16	Delivery of electricity to grid	CO_2	n/a	Excluded	This protocol does not cover displacement of GHG emissions from the use of CMM for grid-connected electricity generation.
		CH_4			
		N_2O			
	Project construction and decommissioning emissions	CO_2	n/a	Excluded	Excluded for simplification. This emission source is assumed to be very small.
		CH_4			
		N_2O			

5 Quantifying GHG Emission Reductions

ER
Equation 5.1 GHG Emission Reductions

Emission Reductions = Baseline Emissions – Project Emissions

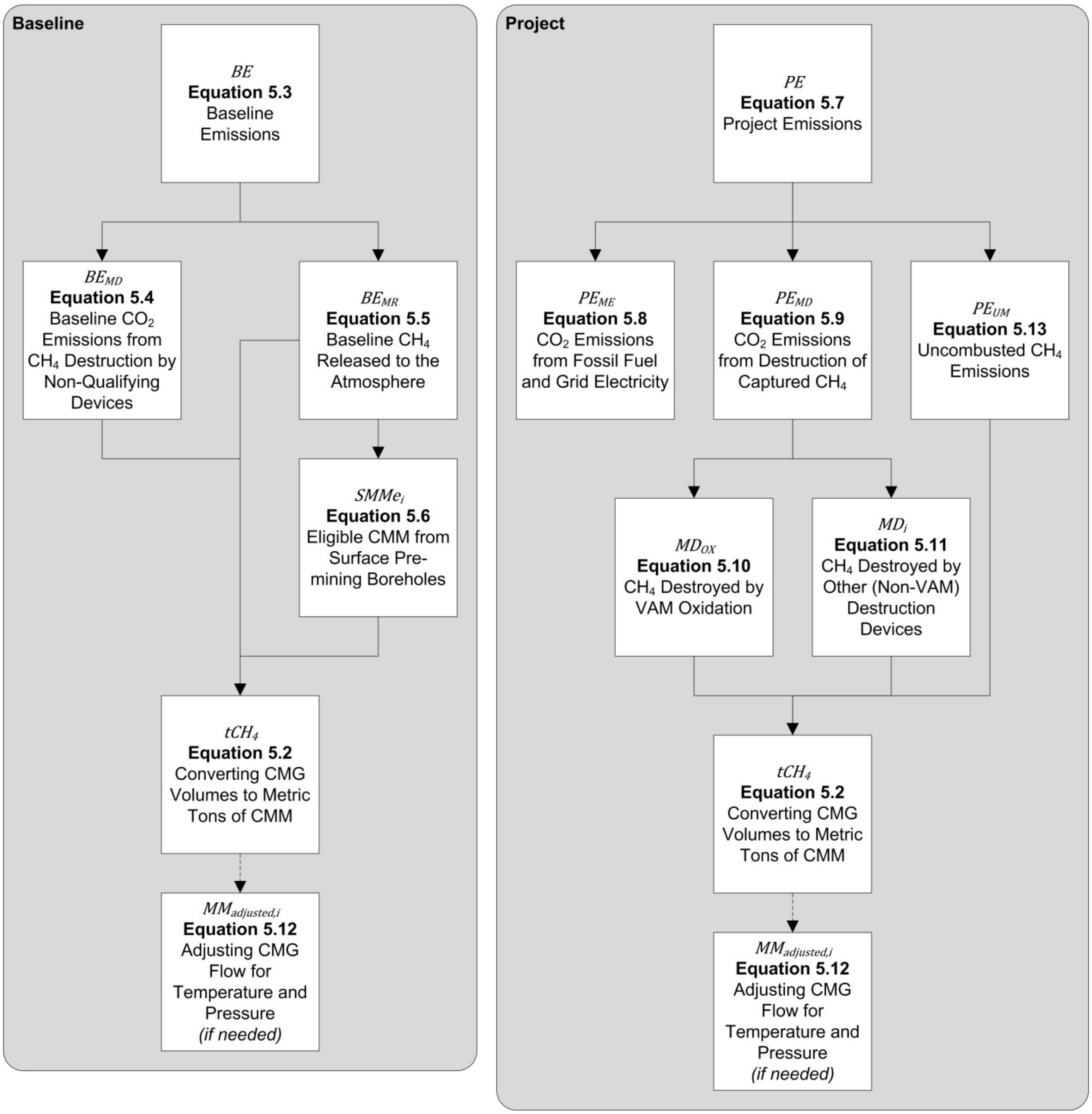


Figure 5.1. Organizational Chart for Equations in Section 5

GHG emission reductions from a coal mine methane project are quantified by comparing actual project emissions to baseline emissions at the mine. Baseline emissions are an estimate of the GHG emissions from sources within the GHG Assessment Boundary (see Section 0) that would have occurred in the absence of the coal mine methane project. Project emissions are actual

GHG emissions that occur at sources within the GHG Assessment Boundary. Project emissions must be subtracted from the baseline emissions to quantify the project's total net GHG emission reductions (Equation 5.1).

GHG emission reductions must be quantified and verified on at least an annual basis. Project developers may choose to quantify and verify GHG emission reductions on a more frequent basis if they desire. The length of time over which GHG emission reductions are quantified and verified is called the "reporting period."

Equation 5.1. GHG Emission Reductions

$$ER = BE - PE$$

Where,			Units
ER	=	GHG emission reductions of the project activity during the reporting period	tCO_2e
BE	=	Baseline emissions during the reporting period	tCO_2e
PE	=	Project emissions during the reporting period	tCO_2e

The calculations provided in this protocol are derived from internationally accepted methodologies.[14] Project developers shall use the calculation methods provided in this protocol to determine baseline and project GHG emissions in order to quantify GHG emission reductions.

Equation 5.2 provides guidance for calculating the mass of methane from the independently measured parameters of gas volume and methane concentration. Note that Equation 5.2 distinguishes between *coal mine gas* (CMG), which is the gas that comes out of the boreholes before any processing or enrichment and often contains various levels of other compounds (e.g. nitrogen, oxygen, carbon dioxide, hydrogen sulfide, NMHC, etc.) and *coal mine methane* (CMM), which represents only the methane portion of CMG.

Throughout the protocol, it is assumed that measured quantities of coal mine gas are converted to metric tons of methane using the following three parameters:

- Measured methane concentration of the coal mine gas
- Volume of gas, corrected to standard conditions (60°F and 1 atm)
- Density of methane at standard conditions (60°F and 1 atm)

[14] The Reserve's GHG reduction calculation method for CMM projects is derived from the UNFCCC approved consolidated methodology under the Kyoto Protocol's Clean Development Mechanism (ACM0008/Version 6), and also draws from Greenhouse Gas Services Methodology for Coal Mine Methane and Abandoned Mine Methane Capture and Destruction Projects (Version 1.1), the U.S. EPA Inventory of U.S. GHG Emissions and Sinks 1990-2007, and the 2006 IPCC Guidelines for National GHG Inventories.

Equation 5.2. Converting CMG Volumes to Metric Tons of CMM

$$tCH_4 = (0.0423 \times 0.000454) \times \sum_t scfCMG_t \times \%CH_{4t}$$

Where,			Units
tCH_4	=	Total quantity of CMM	tCH_4
t	=	Time interval for which flow and concentration measurements are aggregated (daily)	
$\%CH_{4t}$	=	The average methane fraction of the CMG in time interval t as measured	scf CH_4/scf
$scfCMG_t$	=	Total volume of coal mine gas in time interval t, as measured (see Equation 5.12 for additional guidance on adjusting the CMG flow for temperature and pressure)	scf CMG
0.0423	=	Density of methane	lb CH_4/scf CH_4
0.000454	=	tCH_4/lb CH_4	t/lb

5.1 Quantifying Baseline Emissions

Total baseline emissions must be estimated by calculating and summing the expected baseline emissions for all relevant SSRs (as indicated in Table 4.1) using Equation 5.3 and the supporting equations presented below.

Equation 5.3. Baseline Emissions

$$BE = BE_{MD} + BE_{MR}$$

Where,			Units
BE	=	Baseline emissions during the reporting period	tCO_2e
BE_{MD}	=	Baseline emissions from destruction of methane during the reporting period	tCO_2e
BE_{MR}	=	Baseline emissions from release of methane into the atmosphere during the reporting period	tCO_2e

Baseline emissions from CMM release or destruction may be associated with four different stages of mining activity:

1. Surface pre-mining: boreholes are drilled from the surface to unmined portions of the coal seam in advance of mining. CMM drained from surface pre-mining boreholes is represented as SMM in the equations below.

2. Horizontal pre-mining: boreholes are drilled horizontally from within the mine into unmined blocks of coal shortly before mining occurs (also referred to as in-mine boreholes). CMM drained from horizontal pre-mining boreholes is represented as HMM in the equations below.

3. Ventilation during mining through required ventilation systems. CMM collected from ventilation systems is represented as VAM in the equations below.

4. Post-mining: boreholes are drilled from the surface to a point 10 to 50 feet above the coal seam in advance of mining. As mining advances under and past the well, the strata above the coal seam collapses into the mined out area creating a de-pressurized zone extending up to the well; this zone is called the gob. CMM drained from post-mining boreholes is represented as PMM in the equations below.

5.1.1 Calculating Baseline Carbon Dioxide Emissions from Methane Destruction

Depending on the mine, some CMM may be destroyed in the baseline through flaring, oxidation, power generation, heat generation, etc., in non-qualifying destruction devices (see Section 2.2.3). Baseline emissions estimates must include the estimated CO_2 emissions from the destruction of CMM in non-qualifying devices, calculated using Equation 5.4.

The amount of CMM destroyed in the baseline by a non-qualifying destruction device (variables $SMM_{BL,i}$, $HMM_{BL,i}$, $PMM_{BL,i}$ and $VAM_{BL,i}$ in Equation 5.4) is established by calculating and comparing:

1. The actual amount of SMM, HMM, PMM and VAM destroyed by the non-qualifying destruction device during the reporting period; and
2. The amount of SMM, HMM, PMM and VAM destroyed by the non-qualifying destruction device over the three year period prior to the implementation of the project (or however long the non-qualifying destruction device has been operational, whichever is shorter), averaged according to the length of the reporting period. For example, if the reporting period is three months, then the three-year historical amount must be divided by 12 to derive the average amount of destruction in a three-month period.

The higher of either (1) or (2) must be used for $SMM_{BL,i}$, $HMM_{BL,i}$, $PMM_{BL,i}$ and $VAM_{BL,i}$ in Equation 5.4 (and Equation 5.5 in the next section).

Baseline emissions estimates must also include the CO_2 emissions from the destruction of non-methane hydrocarbons (NMHC) in non-qualifying devices, if NMHC comprise more than 35,000 mg/m^3 (measured on a wet basis at standard conditions) of extracted CMG or more than 3,500 mg/m^3 (measured on a wet basis at standard conditions) of extracted ventilation air.

If a non-qualifying destruction device in operation at the mine that was shut down less than one year prior to the project start date – or if a non-qualifying device is shut down at any point during the project's crediting period – the project developer must still account for the device in the baseline calculations, using the historical destruction amount calculated in (2), above. If the device was shut down more than one year before the project start date, it does not need to be accounted for in the baseline calculations.

If there is no destruction of methane in the baseline, then $BE_{MD} = 0$.

5.1.1.1 Treatment of CMM Sent to Pipeline

At some mines, the baseline may involve sending some CMM to a natural gas pipeline for off-site consumption/destruction. The pipeline could therefore be considered a "non-qualifying device." However, because on-site CMM destruction projects are unlikely to affect the quantity of CMM delivered to pipelines (due to the likely physical and temporal separation of these activities), emissions associated with pipelines are excluded from the GHG Assessment Boundary, and do not need to be accounted for in the baseline or the project emission calculations.

If a mine that has historically sent CMM to a pipeline ceases to do so, CMM from that drainage system (i.e. SMM, HMM or PMM) is not eligible for emission reductions, even if CMM is sent to an otherwise eligible destruction device. Furthermore, if a project mine begins to send CMM to a pipeline while a CMM project is still ongoing, CMM from that drainage system will also be deemed ineligible from that point in time forward.

Equation 5.4. Baseline CO_2 Emissions from CH_4 Destruction by Non-Qualifying Devices

$$BE_{MD} = \left(2.75 + r \times CEF_{NMHC}\right) \times \sum_i \left(SMM_{BL,i} + VAM_{BL,i} + HMM_{BL,i} + PMM_{BL,i}\right)$$

Where,			Units
BE_{MD}	=	Baseline emissions from destruction of methane in the reporting period	tCO_2e
i	=	Use of methane (flaring, power generation, heat generation, etc.). Uses must include all non-qualifying devices	
$SMM_{BL,i}$	=	CMM from surface pre-mining that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4
$VAM_{BL,i}$	=	VAM that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4
$HMM_{BL,i}$	=	CMM from horizontal pre-mining that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4
$PMM_{BL,i}$	=	Post-mining CMM that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4
2.75	=	CO_2 emission factor for combusted methane[15]	tCO_2e/tCH_4
CEF_{NMHC}	=	CO_2 emission factor for combusted non methane hydrocarbons	$tCO_2e/tNMHC$
r	=	Relative mass proportion of NMHC compared to methane	

With:

$$r = PC_{NMHC} / PC_{CH_4}$$

Where,			Units
r	=	Relative mass proportion of NMHC compared to methane	
PC_{NMHC}	=	NMHC concentration (in mass) in extracted CMG or ventilation air, measured on a wet basis	mg/m^3
PC_{CH4}	=	Concentration (in mass) of methane in extracted CMG or ventilation air, measured on wet basis at standard conditions (60°F and 1 atm)	mg/m^3

[15] Use the molar mass of CO_2 and CH_4 to calculate tCO_2e/tCH_4 (44/16 = 2.75).

5.1.2 Calculating Baseline Methane Emissions

Baseline emissions must include the methane that would have been emitted to the atmosphere in the absence of the project activity. Baseline emissions of methane are calculated by summing the total amount of methane *actually destroyed* by all qualifying and non-qualifying devices during the reporting period, and subtracting the amount that would have been destroyed in the baseline, as determined in Section 5.1.1. The difference between the actual amount of methane destroyed and what would have been destroyed determines how much methane would have been released. Baseline methane emissions must be calculated using Equation 5.5.

In Equation 5.5, actual methane destruction at all qualifying devices (those installed as part of the project to destroy methane) and non-qualifying devices must be accounted for. For qualifying devices, baseline values for methane destruction (i.e. $SMM_{BL,i}$, $HMM_{BL,i}$, $PMM_{BL,I}$, and $VAM_{BL,i}$) will be zero.

Baseline methane emissions from surface pre-mining (SMM) are quantified only during reporting periods in which the emissions *would have occurred* (i.e. when the borehole is mined through). Thus, baseline methane emissions from SMM must be determined according to the amount of *eligible* CMM that has been destroyed, as defined in Section 5.1.2.1.

If a qualifying device for a VAM project uses CMM to supplement the flow of VAM, the supplemental CMM must be accounted for in Equation 5.5 according to its source (SMM, HMM or PMM) if VAM flow and supplemental CMM flow are monitored separately, or directly through $VAM_{PJ,i}$ if only the resulting enriched flow is monitored.

Any methane that is still vented in the project scenario is not accounted for in the project emissions or baseline emissions, since it is vented in both scenarios. Similarly, the methane that is injected into natural gas pipeline in the project scenario is not accounted for in the project emissions or baseline emissions, since it is injected in both scenarios.

Equation 5.5. Baseline CH_4 Released to the Atmosphere

$$BE_{MR} = GWP_{CH_4} \times \left[\begin{array}{l} \sum_i \left(SMMe_i - SMM_{BL,i}\right) + \sum_i \left(HMM_{PJ,i} - HMM_{BL,i}\right) \\ + \sum_i \left(PMM_{PJ,i} - PMM_{BL,i}\right) + \sum_i \left(VAM_{PJ,i} - VAM_{BL,i}\right) \end{array} \right]$$

Where,			<u>Units</u>
BE_{MR}	=	Baseline methane emissions avoided by the project activity in the reporting period	tCO_2e
i	=	Use of methane (flaring, power generation, heat generation, etc.). *Uses must include all qualifying and non-qualifying devices*	
$SMMe_i$	=	*Actual* amount of CMM from surface pre-mining captured, sent to and destroyed by use i for the reporting period. For qualifying devices, only the *eligible* amount shall be quantified (see Section 5.1.2.1)	tCH_4
$SMM_{BL,i}$	=	CMM from surface pre-mining that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period, as determined in Section 5.1.1	tCH_4
$HMM_{PJ,i}$	=	*Actual* amount of CMM from horizontal pre-mining captured, sent to and destroyed by use i in the reporting period	tCH_4
$HMM_{BL,i}$	=	CMM from horizontal pre-mining that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period, as determined in Section 5.1.1	tCH_4
$PMM_{PJ,i}$	=	*Actual* amount of post-mining CMM captured, sent to and destroyed by use i in the project activity in the reporting period	tCH_4
$PMM_{BL,i}$	=	Post-mining CMM that would have been captured, sent to and destroyed by use I in the baseline scenario in the reporting period, as determined in Section 5.1.1	tCH_4
$VAM_{PJ,i}$	=	*Actual* amount of VAM sent to and destroyed by use i in the project activity in the reporting period. In the case of oxidation, $VAM_{PJ,i}$ is equivalent to MM_{OX} defined in Section 5.2.2	tCH_4
$VAM_{BL,i}$	=	VAM that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period, as determined in Section 5.1.1	tCH_4
GWP_{CH4}	=	Global warming potential of methane (21)	tCO_2e/tCH_4

5.1.2.1 Determining Eligible SMM

To determine the amount of baseline SMM that is eligible to be quantified in a given reporting period, project developers shall identify what boreholes within the bounds of active coal extraction were “mined through” during the reporting period. The most current mine plan shall be used to identify these boreholes.

Baseline SMM emissions are quantified only when the endpoint of the borehole is mined through. If the mine plan calls for mining past rather than through the borehole, then quantification is allowed once the linear distance between the endpoint of the borehole and the working face that will pass nearest the endpoint of the borehole has reached an absolute minimum.

For the purposes of this protocol, mined through is defined as any of the following:

- The working face intersects the endpoint of the borehole
- The working face passes directly underneath the bottom of the borehole, as long as the endpoint of the borehole is within a -50 meter to +150 meter vertical range of the mined coal seam
- The working face intersects the plane of the borehole
- The working face passes both underneath and to the side of the borehole (which will happen when the bottom of the borehole lies above a block of coal that will be left unmined as a pillar)

Once a borehole is mined through, SMM from that borehole that was captured and destroyed by a qualifying device in previous reporting periods may be reported and quantified for the current reporting period (as a component of $SMMe_i$ in Equation 5.5). $SMMe_i$ is calculated as the sum of SMM captured and destroyed by qualifying devices from wells mined through in the current reporting period ($SMMpre_e$), plus SMM captured and destroyed by qualifying devices from wells that were mined through in previous reporting periods ($SMMpost_e$) – see Equation 5.6.

Equation 5.6. Eligible CMM from Surface Pre-mining Boreholes

$$SMMe_i = SMMpre_e + SMMpost_e$$

Where,			<u>Units</u>
$SMMe_i$	=	Actual amount of CMM from surface pre-mining captured, sent to and destroyed by use i that is *eligible* for quantification in the reporting period	tCH_4
$SMMpre_e$	=	Actual amount of CMM destroyed by qualifying devices from surface pre-mining boreholes that were mined through during the current reporting period	tCH_4
$SMMpost_e$	=	Actual amount of CMM destroyed by qualifying devices in the current reporting period from surface pre-mining boreholes that were previously mined through	tCH_4

And:

$$SMMpre_e = \sum_{w_1} \left(SMM_{w_1} \right)$$

Where,			<u>Units</u>
$SMMw_1$	=	Total actual amount of CMM captured and destroyed from well w_1 from the project start date through the end of the current reporting period	tCH_4
w_1	=	The set of wells mined through during the current reporting period	

And:

$$SMMpost_e = \sum_{w_2} \left(SMM_{w_2} \right)$$

Where,			<u>Units</u>
$SMMw_2$	=	Actual amount of CMM captured and destroyed from well w_2 during the current reporting period	tCH_4
w_2	=	The set of wells mined through prior to the current reporting period	

For example, at a mine in which five surface pre-mining wells had been drilled and whose reporting period is 12 months long, if all five wells are mined through in year 4, then in years 1 to 3 the eligible CMM from surface pre-mining would be zero. In year 4 it would be the cumulative volume for the previous three years plus the volume extracted in year 4. In year 5, it would only be the volume extracted in year 5.

5.2 Quantifying Project Emissions

Project emissions must be quantified at a minimum on an annual, *ex-post* basis. As shown in Equation 5.7, project emissions equal the sum of:

- CO_2 emissions from energy used to collect, process, transport and destroy CMM/VAM
- CO_2 emissions from CMM/VAM destroyed in qualifying and non-qualifying destruction devices
- Uncombusted CH_4 emissions from qualifying and non-qualifying destruction devices

Equation 5.7. Project Emissions

$$PE = PE_{ME} + PE_{MD} + PE_{UM}$$

Where,			Units
PE	=	Project emissions during the reporting period	tCO_2e
PE_{ME}	=	Project emissions from energy required for methane collection, transport, and combustion during the reporting period	tCO_2e
PE_{MD}	=	Project emissions from methane destroyed during the reporting period	tCO_2e
PE_{UM}	=	Project emissions from uncombusted methane during the reporting period	tCO_2e

5.2.1 Project Emissions from Energy Required for Methane Collection, Transport, and Combustion

Included in the GHG Assessment Boundary are carbon dioxide emissions resulting from fossil fuel combustion and/or use of grid-delivered electricity for on-site equipment that is used for:

- VAM collection
- Compressors, blowers and/or CMM gathering systems
- Transporting CMM to on-site combustion
- Liquefaction, compression and storage of liquid natural gas (LNG) or compressed natural gas (CNG) created from CMM
- Transporting CMM to boilers/engines for power generation
- Transporting CMM to a flare

If the project utilizes fossil fuel or grid electricity to power equipment necessary for performing the above processes, the resulting project carbon dioxide emissions shall be calculated per Equation 5.8 below. Note that fossil fuel or grid electricity to power equipment installed for the safety of the mine shall be excluded, as that equipment is not within the GHG Assessment Boundary of the project.

Equation 5.8. CO_2 Emissions from Fossil Fuel and Grid Electricity

$$PE_{ME} = \left(CONS_{ELEC,PJ} \times CEF_{ELEC}\right) + \frac{\left(CONS_{HEAT,PJ} \times CEF_{HEAT} + CONS_{FossFuel,PJ} \times CEF_{FossFuel}\right)}{1000}$$

Where,			Units
PE_{ME}	=	Project emissions from energy required for methane collection, transport, and combustion during the reporting period	tCO_2e
$CONS_{ELEC,PJ}$*	=	Additional electricity consumption for destruction of methane during the reporting period, if any	MWh
CEF_{ELEC}	=	CO_2 emission factor of electricity used by mine during the reporting period [16]	tCO_2/MWh
$CONS_{HEAT,PJ}$	=	Additional heat consumption for destruction of methane during the reporting period, if any	volume
CEF_{HEAT}	=	CO_2 emissions factor of heat used by mine during the reporting period; see Appendix B for guidance on deriving emission factor	kg CO_2/ volume
$CONS_{FossFuel,PJ}$	=	Additional fossil fuel consumption for destruction of methane during the reporting period, if any	volume
$CEF_{FossFuel}$	=	CO_2 emission factor of fossil fuel used by mine during the reporting period; see Appendix B for emission factors by fuel type	kg CO_2/ volume
1/1000	=	Conversion of kg to metric tons	

* If total electricity being generated by project activities is $\geq$ the additional electricity consumption, then $CONS_{ELEC,PJ}$ shall not be accounted for in the project emissions and shall be omitted from the equation above.

5.2.2 Project Emissions from Destruction of Captured Methane

When CMM/VAM is burned in a flare, heat or power plant, or oxidized in an oxidation unit, carbon dioxide emissions are released and must be accounted for. In addition, if NMHC comprise more than 35,000 mg/m^3 (measured on a wet basis at standard conditions) of extracted CMG or more than 3,500 mg/m^3 (measured on a wet basis at standard conditions) of extracted ventilation air, carbon dioxide emissions from combustion of NMHC must also be accounted for.

Equation 5.9 must be used to calculate carbon dioxide emissions from destruction of captured methane at qualifying and non-qualifying devices.

Note: Although baseline methane emissions from surface pre-mining are accounted for only when they are eligible (i.e. after the borehole is mined through), carbon dioxide emissions

[16] Refer to the version of the U.S. EPA eGRID that most closely corresponds to the time period during which the electricity was used. The project shall use the annual total output emission rates for the subregion where the project is located, not the non-baseload output emission rates. The eGRID tables are available from the U.S. EPA website: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

resulting from the destruction of surface pre-mining CMM must be accounted for in the period during which the destruction occurs, using Equation 5.9.

Equation 5.9. CO_2 Emissions from Destruction of Captured CH_4

$$PE_{MD} = \left(MD_{OX} + MD_i\right) \times \left(2.75 + r \times CEF_{NMHC}\right)$$

With:

$$r = {PC_{NMHC}} \big/ {PC_{CH_4}}$$

Where,

			Units
PE_{MD}	=	Project emissions from methane destroyed during the reporting period	tCO_2e
MD_i[17]	=	Methane destroyed by all qualifying and non-qualifying devices during the reporting period	tCH_4
MD_{OX}	=	Methane destroyed through oxidation during the reporting period	tCH_4
2.75	=	CO_2 emission factor for combusted methane	tCO_2/tCH_4
CEF_{NMHC}	=	CO_2 emission factor for combusted NMHC[18]	tCO_2/tNMHC
r	=	Relative mass proportion of NMHC compared to methane	
PC_{NMHC}	=	NMHC concentration (in mass) in extracted CMG or ventilation air, measured on a wet basis at standard conditions (60°F and 1 atm)	mg/m^3
PC_{CH4}	=	Concentration (in mass) of methane in extracted CMG or ventilation air, measured on wet basis at standard conditions	mg/m^3

For each end-use destruction device (qualifying and non-qualifying), the amount of gas destroyed depends on the efficiency of combustion for that destruction device. For VAM project destruction devices, Equation 5.10 must be used to quantify the methane destroyed by oxidation, which accounts for the destruction efficiency of the oxidation unit on a continuous basis. For drainage project destruction devices, Equation 5.11 must be used to quantify the methane destroyed for each qualifying and non-qualifying device.

Using Equation 5.11, project developers have the option to use either the default methane destruction efficiencies provided in Appendix B, or site-specific methane destruction efficiencies. Site specific destruction efficiencies for each qualifying or non-qualifying device must be determined by a source-test service provider accredited by a state or local agency. If the project developer chooses to use site-specific destruction efficiencies, the destruction device shall be source tested at least annually and the destruction efficiency updated accordingly.

[17] MD_i includes methane from all SMM sent to qualifying devices, not just eligible SMM.
[18] Because concentrations of different NMHC components may vary over time, the appropriate emission factor shall be obtained through annual analysis of captured gas from each drainage system type.

Equation 5.10. CH_4 Destroyed by VAM Oxidation

$$MD_{OX} = MM_{OX} - PE_{OX}$$

Where,			Units
MD_{OX}	=	Methane destroyed through oxidation during the reporting period	tCH_4
MM_{OX}	=	Methane measured sent to oxidizer during the reporting period	tCH_4
PE_{OX}	=	Project emissions of non-oxidized CH_4 from oxidation of the VAM stream during the reporting period	tCH_4

And:

$$MM_{OX} = VAM_{flow.rate,y} \times time_y \times PC_{CH_4.VAM} \times D_{CH_4}$$

Where,			Units
$VAM_{flow.rate,y}$	=	Average flow rate of ventilation air entering the oxidation unit during period y corrected if needed for inlet flow gas pressure and temperature ($P_{VAMinflow}$ and $T_{VAMinflow}$ respectively) per Equation 5.12	scfm
$time_y$	=	Time during which VAM unit is operational during period y	m
$PC_{CH4.VAM}$	=	Concentration of methane in the ventilation air entering the oxidation unit corrected if needed for pressure and temperature in the vicinity of the methane analyzer	scf/scf
D_{CH4}	=	Density of methane under standard conditions	tCH_4/scf

And:

$$PE_{OX} = VAM_{flow.rate,y} \times time_y \times PC_{CH_4.exhaust} \times D_{CH_4}$$

Where,			Units
$PC_{CH4.exhaust}$	=	Concentration of methane in the ventilation air exhaust corrected if needed for pressure and temperature in the vicinity of the methane analyzer ($P_{VAManalyzerinflow}$, $T_{VAManalyzerinflow}$, $P_{VAMnalyzerexhaust}$, and $T_{VAManalyzerexhaust}$)	scf/scf
D_{CH4}	=	Density of methane under standard conditions	tCH_4/scf

Equation 5.11. CH_4 Destroyed by Other (Non-VAM) Destruction Devices

$$MD_i = \sum_i MM_i \times DE_i$$

Where,			Units
MD_i	=	Methane destroyed by all qualifying and non-qualifying devices i during the reporting period	tCH_4
MM_i	=	Methane measured sent to use i during the reporting period	tCH_4
DE_i	=	Efficiency of methane destruction device i; see Appendix B for default destruction efficiencies by destruction device[19]	%

Equation 5.12. Adjusting CMG Flow for Temperature and Pressure

Important: Apply the following equation only if the CMG flow metering equipment does not internally correct for temperature and pressure.

$$MM_{adjusted,i} = MM_{unadjusted,i} \times \frac{520}{T} \times \frac{P}{1}$$

Where,			Units
$MM_{adjusted,i}$	=	Adjusted volume of CMG collected for the given time interval at utilization type i, adjusted to 60°F and 1 atm	scf/unit time
$MM_{unadjusted,i}$	=	Unadjusted volume of CMG collected for the given time interval at utilization type i	scf/unit time
T	=	Measured temperature of the CMG for the given time period (°R = °F + 460)	°R
P	=	Measured pressure of the CMM for the given time interval	atm

[19] Project developers have the option to use either the default methane destruction efficiencies provided, or site specific methane destruction efficiencies as provided by a state or local agency accredited source test service provider, for each of the combustion devices used in the project.

5.2.3 Project Emissions from Uncombusted Methane

Not all of the methane sent to the flare, to the oxidizer or used to generate heat and power will be combusted; a small amount will escape to the atmosphere. These emissions are calculated using Equation 5.13.

As in Equation 5.11, project developers again have the option to use either the default methane destruction efficiencies provided in Appendix B, or site specific methane destruction efficiencies in Equation 5.13. If the project developer chooses to use site specific destruction efficiencies in Equation 5.11, they must use the same destruction efficiencies in Equation 5.13.

Equation 5.13. Uncombusted CH_4 Emissions

$$PE_{UM} = \left[GWP_{CH_4} \times \sum_i MM_i \times \left(1 - DE_i\right) \right] + PE_{OX} \times GWP_{CH_4}$$

Where,			<u>Units</u>
PE_{UM}	=	Project emissions from uncombusted methane during the reporting period	tCO_2e
GWP_{CH4}	=	Global warming potential of methane (21)	tCO_2e/tCH_4
i	=	The set of all qualifying and non-qualifying devices	
MM_i	=	Methane measured sent to use i during the reporting period	tCH_4
DE_i	=	Efficiency of methane destruction in use i; see Appendix B for default destruction efficiencies by destruction device[20]	%
PE_{OX}	=	Project emissions of non oxidized methane from oxidation of the VAM stream during the reporting period	tCH_4

[20] Project developers have the option to use either the default methane destruction efficiencies provided, or site specific methane destruction efficiencies as provided by a state or local agency accredited source test service provider, for each of the combustion devices used in the project.

6 Project Monitoring

The Reserve requires a Monitoring Plan to be established for all monitoring and reporting activities associated with the project. The Monitoring Plan will serve as the basis for verification bodies to confirm that the monitoring and reporting requirements in this section and Section 7 have been and will continue to be met, and that consistent, rigorous monitoring and record-keeping is ongoing at the project site. The Monitoring Plan must cover all aspects of monitoring and reporting contained in this protocol and must specify how data for all relevant parameters in Table 6.1 (below) will be collected and recorded.

At a minimum the Monitoring Plan shall stipulate the frequency of data acquisition; a record keeping plan (see Section 7.3 for minimum record keeping requirements); the frequency of instrument cleaning, inspection, field check and calibration activities; and the role of individuals performing each specific monitoring activity. The Monitoring Plan should include QA/QC provisions to ensure that data acquisition and meter calibration are carried out consistently and with precision. The Monitoring Plan shall also contain a detailed diagram of the coal mine gas collection and destruction system, including the placement of all meters and equipment that affect SSRs within the GHG Assessment Boundary (see Figure 4.1 and Figure 4.2).

Finally, the Monitoring Plan must include procedures that the project developer will follow to ascertain and demonstrate that the project at all times passes the Legal Requirement Test (Section 3.4.1).

Project developers are responsible for monitoring the performance of the project and ensuring that the operation of CMM destruction devices is consistent with the manufacturer's recommendations for each piece of equipment.

6.1 Monitoring Requirements

For drainage projects, the drainage systems and methane destruction devices must be monitored with measurement equipment that directly meters:

- The total flow of CMG from each drainage system defined as part of a project, measured continuously and recorded every 15 minutes or totalized and recorded at least daily, adjusted for temperature and pressure

- The flow of CMG delivered to each destruction device (unless otherwise allowed by Section 6.1.1), measured continuously and recorded every 15 minutes or totalized and recorded at least daily, adjusted for temperature and pressure

- The fraction of methane in the CMG from each drainage system, measured continuously and recorded every 15 minutes and averaged at least daily

For VAM projects, monitoring requirements include:

- The total inlet flow entering the oxidation unit, measured continuously and recorded every two minutes to calculate average flow per hour

- The fraction of methane in the ventilation air entering the oxidation unit and in the exhaust gas, measured continuously and recorded every two minutes to calculate average methane concentration per hour

- If required in order to standardize the flow rate, the temperature and pressure in the vicinity of the flow meter, measured continuously and recorded at least every hour to calculate hourly pressure and temperature.

- If required in order to correct methane concentration readings, the temperature and pressure in the vicinity of the methane analyzer, measured continuously and recorded at least every hour to calculate hourly pressure and temperature.

All flow data collected must be corrected for temperature and pressure at standard conditions (60°F and 1 atm). Equation 5.12 must be applied if flow metering equipment does not make this correction automatically. Depending on the methane analyzer technology used, methane concentration data may or may not need to be corrected for temperature and pressure. If the methane analyzer technology used requires adjustment for temperature and pressure, then concentration data must also be corrected to 60°F and 1 atm.

For both VAM projects and drainage projects, NMHC content of the CMG shall be determined on an annual basis by a full gas analysis using a gas chromatograph at an ISO 17025 accredited lab or a lab that has been certified by an accreditation body conformant with ISO 17025[21] to perform test methods appropriate for NMHC content analysis.[22] Separate gas samples shall be collected by a third-party technician prior to each destruction device within the project definition.

Operational activity of the CMM drainage systems and the destruction devices shall be monitored and documented at least hourly to ensure actual methane destruction. GHG reductions will not be accounted for during periods in which the destruction device is not operational. For flares, operation is defined as thermocouple readings above 500°F. For all other destruction devices, the means of demonstration shall be determined by the project developer and subject to verifier review and professional judgment.

6.1.1 Arrangement of CMG Metering Equipment

For drainage projects, the CMG from each drainage system (i.e. surface pre-mining boreholes, horizontal pre-mining boreholes, or post-mining boreholes) must be monitored separately prior to interconnection with other CMG sources. The volumetric gas flow, methane concentration, temperature, and pressure shall be monitored and recorded separately for each drainage system.

In addition, the flow of gas to each destruction device must be monitored separately for each destruction device, except under certain conditions. Specifically, if all destruction devices are of identical efficiency and verified to be operational throughout the reporting period, a single flow meter may be used to monitor gas flow to all destruction devices. Otherwise, the destruction efficiency of the least efficient destruction device shall be used as the destruction efficiency for all destruction devices monitored by this meter.

If a project using a single meter to monitor gas flow to multiple destruction devices has any periods when not all destruction devices downstream of a single flow meter are operational, methane destruction from the set of downstream devices during these periods will only be

[21] Such as the American Industrial Hygiene Association (AIHA), the American Association for Laboratory Accreditation (A2LA) and the National Environmental Laboratory Accreditation Program (NELAP).
[22] For example, NIOSH method number 1550 for portable gas chromatography.

eligible provided that the verifier can confirm all of the following requirements and conditions are met:

a. The destruction efficiency of the least efficient downstream destruction device in operation shall be used as the destruction efficiency for all destruction devices downstream of the single meter; and
b. All devices are either equipped with valves on the input gas line that close automatically if the device becomes non-operational (requiring no manual intervention), or designed in such a manner that it is physically impossible for gas to pass through while the device is non-operational; and
c. For any period during which one or more downstream destruction devices are not operational, it must be documented that the remaining operational devices have the capacity to destroy the maximum gas flow recorded during the period.

6.2 Instrument QA/QC

Monitoring instruments[23] shall be inspected, cleaned, and calibrated according to the following schedule.

All gas flow meters[24] and continuous methane analyzers must be:

- Cleaned and inspected on a regular basis, as specified in the project's Monitoring Plan, with the activities and results documented by site personnel. Cleaning and inspection frequency must, at a minimum, follow the manufacturer's recommendations.

- Field checked for calibration accuracy by an appropriately trained individual or a third-party technician with the percent drift documented, using either a portable instrument or manufacturer specified guidance, at the end of – but no more than two months prior to or after – the end date of the reporting period.[25] If a portable calibration instrument is used for field checks, the portable instrument shall be maintained and calibrated per the manufacturer's specifications, and calibrated at least annually by the manufacturer or at an ISO 17025 accredited laboratory. For portable methane analyzers, the portable instrument must be field calibrated to a known sample gas prior to each use.

- Calibrated by the manufacturer or a third-party calibration service at the frequency recommended by the manufacturer. If the manufacturer does not specify a recommended calibration schedule, then no calibrations are required, unless a field check reveals a difference of +/- 5% or more.

    - Flow meter calibrations shall be documented to show that the meter was calibrated to a range of flow rates corresponding to the flow rates expected at the mine.
    - Methane analyzer calibrations shall be documented to show that the calibration was carried out to the range of conditions (temperature and pressure) corresponding to the range of conditions as measured at the mine.

[23] If separate instruments are used for monitoring temperature and pressure, these instruments must also meet the specified QA/QC guidelines.
[24] Field checks and calibrations of flow meters shall assess the volumetric output of the flow meter.
[25] Instead of performing field checks, the project developer may have equipment calibrated by the manufacturer or a third-party calibration service per manufacturer's guidance, at the end of, but no more than two months prior to or after, the end date of the reporting period to meet this requirement.

If the field check on a piece of equipment reveals a difference of +/- 5% or more between the value measured by the portable calibration instrument and the value measured by the monitoring instrument, calibration by the manufacturer or a third-party calibration service is required for that piece of equipment.

For the interval between the last successful field check/calibration and any field check/calibration event revealing accuracy outside the +/- 5% threshold, all data from that meter or analyzer must be scaled according to the following procedure based on the results of the calibration report from the manufacturer or third-party service provider. These adjustments must be made for the entire period from the last successful field check/calibration until such time as the meter is properly calibrated and in place.

1. For calibrations that indicate an underestimation of emission reductions, the metered values must be used without correction.

2. For calibrations that indicate an overestimation of emission reductions, the metered values must be adjusted based on the greatest calibration drift recorded at the time of calibration.

For example, if a project conducts field checks quarterly during a year-long reporting period, then only three months of data will be subject at any one time to the penalties above. However, if the project developer feels confident that the meter does not require field checks or calibration more than annually, then failed events will accordingly require the adjustments above to be applied to the entire year's data. Further, frequent calibration may minimize the total accrued drift (by zeroing out any error identified), and result in smaller overall deductions.

In order to provide flexibility in verification, data monitored up to two months after a field check may be verified. As such, the end date of the reporting period must be no more than two months after the latest successful field check. A field check conducted up to two months after the end date of a reporting period is also acceptable to confirm the accuracy of the equipment during the reporting period. Note that while a field check completed outside of the 12 month reporting period may be used, only the 12 months of data specified as the reporting period can be verified.

Project developers have the option to use either the default methane destruction efficiencies provided in the protocol, or the site-specific methane destruction efficiencies as provided by a state- or local agency-accredited source test service provider, for any of the destruction devices used in the project, performed on an annual basis. Device-specific source testing shall include at least three test runs, with the accepted final value being one standard deviation below the mean of the measured efficiencies.

6.3 Missing Data

In situations where the flow rate or methane concentration monitoring equipment is missing data, the project developer shall apply the data substitution methodology provided in Appendix C. If for any reason the destruction device monitoring equipment is inoperable (for example, the thermocouple on the flare), then no emission reductions can be credited for the period of inoperability.

6.4 Monitoring Parameters

Prescribed monitoring parameters necessary to calculate baseline and project emissions are provided in Table 6.1.

Table 6.1. Coal Mine Methane Project Monitoring Parameters

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
5.4 5.5	$SMM_{BL,i}$	CMM from surface pre-mining that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4	Estimated at start of project and calculated annually, if non-qualifying destruction device is still in place	c, m	The higher of the two calculated values is used
5.4 5.5	$HMM_{BL,i}$	CMM from horizontal pre-mining that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4	Estimated at start of project and calculated annually, if non-qualifying destruction device is still in place	c, m	The higher of the two calculated values is used
5.4 5.5	$PMM_{BL,i}$	Post-mining CMM that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4	Estimated at start of project and calculated annually, if non-qualifying destruction device is still in place	c, m	The higher of the two calculated values is used
5.4 5.5	$VAM_{BL,i}$	VAM that would have been captured, sent to and destroyed by use i in the baseline scenario in the reporting period	tCH_4	Estimated at start of project and calculated annually, if non-qualifying destruction device is still in place	c, m	The higher of the two calculated values is used
5.4 5.9	CEF_{NMHC}	CO_2 emission factor for combusted non methane hydrocarbons (various)	tCO_2e/ tNMHC	Annually	m	To be obtained through analysis of the fractional composition of captured gas
5.4 5.9	PC_{CH4}	Concentration (in mass) of methane in extracted CMG or ventilation air , measured on wet basis	mg/m^3	Continuous	m	To be measured on wet basis
5.4 5.9	PC_{NMHC}	NMHC concentration (in mass) in extracted CMG or ventilation air	mg/m^3	Annually	m	Based on full gas analysis by a certified gas lab using a gas chromatograph
5.5 5.6	$SMMe_i$	CMM from surface pre-mining captured, sent to and destroyed by use i for the reporting period. For qualifying devices, only the *eligible* amount may be quantified	tCH_4	Every reporting period	c, m	Only includes SMM from boreholes that have been "mined through" and SMM destroyed by non-qualifying devices (excluding SMM sent to pipeline)

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
5.5	$HMM_{PJ,i}$	CMM from horizontal pre-mining captured, sent to and destroyed by use i in the reporting period	tCH_4	Continuous	m	Includes metered HMM destroyed by both eligible and non-qualifying devices
5.5	$VAM_{PJ,i}$	VAM sent to and destroyed by use i in the project activity in the reporting period. In the case of oxidation, $VAM_{PJ,i}$ is equivalent to MM_{OX} defined in Section 5.2.2	tCH_4	Continuous	m	Includes metered VAM destroyed by both eligible and non-qualifying devices
5.5	$PMM_{PJ,i}$	CMM from post-mining captured, sent to and destroyed by use i in the project activity in the reporting period	tCH_4	Continuous	m	Includes metered PMM destroyed by both eligible and non-qualifying devices
5.5 5.13	GWP_{CH4}	Global warming potential of methane	$tCO_2e/$ tCH_4		r	21
5.6	$SMMpre_e$	CMM destroyed by qualifying devices in the current reporting period from surface pre-mining boreholes that were mined through during the current reporting period	tCH_4	Every reporting period	m	
5.6	$SMMpost_e$	CMM destroyed by qualifying devices in the current reporting period from surface pre-mining boreholes that were previously mined through	tCH_4	Every reporting period	m	
5.6	$SMMw_1$	CMM captured and destroyed from well w_1 from the project start date through the end of the current reporting period	tCH_4	Every reporting period	m	
5.6	w_1	The set of wells mined through in current reporting period		Every reporting period	o	
5.6	$SMMw_2$	CMM captured from well w_2 during the current reporting period	tCH_4	Every reporting period	m	
5.6	w_2	The set of wells mined through prior to the current reporting period		Every reporting period	o	
5.8	$CONS_{ELEC,PJ}$	Additional electricity consumption for destruction of methane, if any	MWh	Every reporting period	o	From electricity use records
5.8	$CONS_{HEAT,PJ}$	Additional heat consumption destruction of methane	volume	Every reporting period	o	From purchased heat records

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
5.8	$CONS_{FossFuel,PJ}$	Additional fossil fuel consumption for destruction of methane	volume	Every reporting period	o	From fuel use records
5.8	CEF_{ELEC}	CO_2 emissions factor of electricity used by mine	tCO_2/ MWh	Every reporting period	r	See eGRID
5.8	CEF_{HEAT}	CO_2 emissions factor of heat used by mine	kg CO_2/ volume	Every reporting period	c	See Appendix B
5.8	$CEF_{FossFuel}$	CO_2 emissions factor of fossil fuel used by mine	kg CO_2/ volume	Every reporting period	r	See Appendix B
5.9	MD_i	Methane destroyed by all qualifying and non-qualifying devices	tCH_4	Every reporting period	c	
5.10	$VAM_{flow.rate,y}$	Average flow rate of ventilation air entering the oxidation unit during period y	scfm	Continuous	m, c	Readings taken every two minutes to calculate average hourly flow
5.10	$time_y$	Time during which VAM unit is operational during period y	m	Continuous		Readings taken every two minutes to calculate average hourly flow
5.10	D_{CH4}	Density of methane under standard conditions	tCH_4/scf		r	Density of methane under standard conditions (60ºF and 1 atm) = 0.0423 lb/scf
5.10	D_{CH4}	Density of methane under standard conditions	tCH_4/scf		r	Density of methane under standard conditions (60ºF and 1 atm) = 0.0423 lb/scf
5.10	$P_{VAMinflow}$	Pressure of ventilation air entering the oxidation unit	atm	Continuous	m	Readings taken at least every hour to calculate hourly pressure
5.10	$T_{VAMinflow}$	Temperature of ventilation air entering the oxidation unit (ºR = ºF + 460)	ºR	Continuous	m	Readings taken at least every hour to calculate hourly temperature
5.10	$PC_{CH4,VAM}$	Concentration of methane in the ventilation air entering the oxidation unit	scf/scf	Continuous	m	Readings taken at least every two minutes and used to calculate average methane concentration per hour
5.10	$PC_{CH4,exhaust}$	Concentration of methane in the ventilation air exhaust	scf/scf	Continuous	m	Readings taken at least every two minutes (either average over two minutes or instantaneous) and used to calculate average methane concentration per hour

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
5.10	$P_{VAManalyzerinflow}$	Pressure of ventilation air in the vicinity of the VAM methane analyzer at inlet	atm	Continuous	m	If methane analyzer technology requires adjustment for pressure and temperature and the use of $P_{VAMinflow}$ is inappropriate, readings shall be taken in the vicinity of the inlet VAM methane analyzer at least every hour to calculate hourly pressure
5.10	$T_{VAManalyzerinflow}$	Temperature of ventilation air entering the oxidation unit in the vicinity of the VAM methane analyzer	ºR	Continuous	m	If methane analyzer technology requires adjustment for pressure and temperature and the use of $T_{VAMinflow}$ is inappropriate, readings shall be taken in the vicinity of the inlet VAM methane analyzer at least every hour to calculate hourly temperature
5.10	$P_{VAManalyzerexhaust}$	Pressure of exhaust gases in the vicinity of the VAM methane analyzer at inlet	atm	Continuous	m	If methane analyzer technology requires adjustment for pressure and temperature, readings shall be taken in the vicinity of the exhaust VAM methane analyzer at least every hour to calculate hourly pressure
5.10	$T_{VAManalyzerexhaust}$	Temperature of exhaust gases exiting the oxidation unit in the vicinity of the VAM methane analyzer	ºR	Continuous	m	If methane analyzer technology requires adjustment for pressure and temperature, readings shall be taken in the vicinity of the exhaust VAM methane analyzer at least every hour to calculate hourly temperature
5.11 5.13	MM_i	Methane measured sent to use i	tCH_4	Continuous	m	Flow meters will record gas volumes, pressure and temperature
5.11 5.13	Eff_i	Efficiency of methane destruction through use i		Annually	m or r	See Appendix B
5.12	MMadjusted,i	Adjusted volume of CMG collected for the given time interval at use i	scf/unit time	Every reporting period	c	Adjusted to standard conditions (60°F and 1 atm)

Eq. #	Parameter	Description	Data Unit	Measurement Frequency	Calculated (c) Measured (m) Reference (r) Operating records (o)	Comment
5.12	MMunadjusted,i	Unadjusted volume of CMG collected for the given time interval at use i	scf/unit time	Continuously	m	If flow meters do not internally correct for temperature and pressure
5.12	T	Measured temperature of CMG for the given time period (ºR = ºF + 460)	ºR	Continuously	m	Measured to adjust the flow of CMG. No separate monitoring of temperature is necessary when using flow meters that automatically adjust flow volumes for temperature and pressure
5.12	P	Measured pressure of the CMG for the given time interval	atm	Continuously	m	Measured to adjust the flow of CMG. No separate monitoring of pressure is necessary when using flow meters that automatically adjust flow volumes for temperature and pressure

7 Reporting Parameters

This section provides requirements and guidance on reporting rules and procedures. A priority of the Reserve is to facilitate consistent and transparent information disclosure by project developers. Project developers must submit verified emission reduction reports to the Reserve annually at a minimum.

7.1 Project Documentation

Project developers must provide the following documentation to the Reserve in order to register a coal mine methane project.

- Project Submittal form
- Project diagram: diagram that illustrates how the project is defined and includes the location, quantity and type of boreholes, ventilation shafts, eligible destruction devices and non-qualifying destruction devices within the project GHG Assessment Boundary, as well as placement of monitoring equipment
- Signed Attestation of Title form
- Signed Attestation of Voluntary Implementation form
- Signed Attestation of Regulatory Compliance form
- Verification Report
- Verification Statement

Project developers must provide the following documentation each reporting period in order for the Reserve to issue CRTs for quantified GHG reductions:

- Verification Report
- Verification Statement
- Signed Attestation of Title form
- Signed Attestation of Voluntary Implementation form
- Signed Attestation of Regulatory Compliance form

At a minimum, the above project documentation (except for the project diagram) will be available to the public via the Reserve's online registry. Further disclosure and other documentation may be made available by the project developer on a voluntary basis. Project submittal forms can be found at http://www.climateactionreserve.org/how/projects/register/project-submittal-forms/.

7.1.1 Documentation of Project Expansions

If a project expands to include boreholes, ventilation shafts or destruction devices beyond what was included in the project as defined by the project developer at the time of listing (see Section 2.2), the project developer must submit an updated project diagram to the Reserve.

Similarly, if any new non-qualifying device becomes operational at the mine – or if an existing non-qualifying device at a mine is assigned to a different active project (see Section 2.2.3) – the project developer must submit an updated project diagram for the project to which the device is assigned.

7.2 Joint Project Verification

Because the protocol allows for multiple projects at a single mine site, project developers have the option to hire a single verification body to verify multiple projects at a mine through a “joint project verification.” This may provide economies of scale for the project verifications and improve the efficiency of the verification process.

Under joint project verification, each project, as defined by the protocol and the project developer, is submitted, listed and registered separately in the Reserve system. Furthermore, each project requires its own separate verification process and Verification Statement (i.e. each project is assessed by the verification body separately as if it were the only project at the mine). However, all projects may be verified together by a single site visit to the mine. Furthermore, a single Verification Report may be filed with the Reserve that summarizes the findings from multiple project verifications.

Regardless of whether the project developer chooses to verify multiple projects through a joint project verification or pursue verification of each project separately, the documents and records for each project must be retained according to this section.

7.3 Record Keeping

For purposes of independent verification and historical documentation, project developers are required to keep all information outlined in this protocol for a period of 10 years after the information is generated or 7 years after the last verification. This information will not be publicly available, but may be requested by the verifier or the Reserve.

System information the project developer should retain includes:

- All data inputs for the calculation of GHG reductions, including all required sampled data
- Copies of mine operating permits, air, water, and land use permits; Notices of Violations (NOVs); and any administrative or legal consent orders related to project activities dating back at least three years prior to the project start date; and for each subsequent year of project operation[26]
- Copies of mine plans and mine ventilation plans submitted to MSHA throughout the crediting period
- Executed Attestation of Regulatory Compliance related to the project
- Flow meter information (model number, serial number, manufacturer’s calibration procedures)
- Methane monitor information (model number, serial number, calibration procedures)
- Destruction device monitor information (model number, serial number, calibration procedures)
- Field checks and calibration results for all meters
- Corrective measures taken if meter does not meet performance specifications
- Destruction device monitoring data (for each destruction device)
- Project flow and methane concentration data
- Emission reduction calculations
- Verification records and results from each verification
- All maintenance records relevant to the project monitoring equipment and destruction devices

[26] Note that these documentation requirements are for activities and equipment related to the project and the mine where the project is located.

7.4 Reporting Period & Verification Cycle

Project developers must report GHG reductions resulting from project activities during each reporting period. Although projects must be verified annually at a minimum, the Reserve will accept verified emission reduction reports on a sub-annual basis, should the project developer choose to have a sub-annual reporting period and verification schedule (e.g. quarterly or semi-annually). A reporting period cannot exceed 12 months, and no more than 12 months of emission reductions can be verified at once, except during a project's first verification. A project's initial reporting period must begin on the project's start date. Reporting periods must be contiguous; there can be no time gaps in reporting during the crediting period of a project once the initial reporting period has commenced. Project developers may register their project's initial reporting period as a zero-credit reporting period (see Reserve Program Manual, Section 3.3.3 for more details).

8 Verification Guidance

This section provides verification bodies with guidance on verifying GHG emission reductions from coal mine methane projects developed to the standards of this protocol. This verification guidance supplements the Reserve's Verification Program Manual and describes verification activities in the context of coal mine methane destruction projects.

Verification bodies trained to verify coal mine methane projects must conduct verifications to the standards of the following documents:

- Climate Action Reserve Program Manual
- Climate Action Reserve Verification Program Manual
- Climate Action Reserve Coal Mine Methane Project Protocol
- Any applicable errata and clarifications to the Coal Mine Methane Project Protocol
- Any applicable policy memos issued by the Reserve

The Reserve's Program Manual, Verification Program Manual, and project protocols are designed to be compatible with each other and are available on the Reserve's website at http://www.climateactionreserve.org.

In cases where the Program Manual and/or Verification Program Manual differ from the guidance in this protocol, this protocol takes precedent.

Only ISO-accredited verification bodies trained by the Reserve for this project type are eligible to verify coal mine methane project reports. Verification bodies approved under other project protocol types are not permitted to verify coal mine methane projects. Information about verification body accreditation and Reserve project verification training can be found in the Verification Program Manual.

8.1 Verification of Multiple Projects at a Single Mine

Because the protocol allows for multiple projects at a single mine site, project developers have the option to hire a single verification body to verify multiple projects under a joint project verification. This may provide economies of scale for the project verifications and improve the efficiency of the verification process. Joint project verification is only available as an option for a single project developer; joint project verification cannot be applied to multiple projects registered by different project developers at the same mine.

Under joint project verification, each project, as defined by the protocol and the project developer, must still be registered separately in the Reserve system and each project requires its own verification process and Verification Statement (i.e. each project is assessed by the verification body separately as if it were the only project at the mine). However, all projects may be verified together by a single site visit to the mine. Furthermore, a single Verification Report may be filed with the Reserve that summarizes the findings from multiple project verifications.

Finally, the verification body may submit one Notification of Verification Activities/Conflict of Interest (NOVA/COI) Assessment form that details and applies to all of the projects at a single mine that it intends to verify.

If, during joint project verification, the verification activities of one project are delaying the registration of another project, the project developer can choose to forego joint project verification. There are no additional administrative requirements of the project developer or the verification body if a joint project verification is terminated.

8.2 Standard of Verification

The Reserve's standard of verification for coal mine methane projects is the Coal Mine Methane Project Protocol (this document), the Reserve Program Manual, and the Verification Program Manual. To verify a coal mine methane project developer's project report, verification bodies apply the guidance in the Verification Program Manual and this section of the protocol to the standards described in Section 2 through 7 of this protocol. Sections 2 through 7 provide eligibility rules, methods to calculate emission reductions, performance monitoring instructions and requirements, and procedures for reporting project information to the Reserve.

8.3 Monitoring Plan

The Monitoring Plan serves as the basis for verification bodies to confirm that the monitoring and reporting requirements in Section 6 and Section 7 have been met, and that consistent, rigorous monitoring and record-keeping is ongoing at the project site. Verification bodies shall confirm that the Monitoring Plan covers all aspects of monitoring and reporting contained in this protocol and specifies how data for all relevant parameters in Table 6.1 are collected and recorded.

8.4 Verifying Project Eligibility

Verification bodies must affirm a coal mine methane project's eligibility according to the rules described in this protocol. The table below outlines the eligibility criteria for a coal mine methane project. This table does not represent all criteria for determining eligibility comprehensively; verification bodies must also look to Section 3 and the verification items list in Table 8.2.

Table 8.1. Summary of Eligibility Criteria

Eligibility Rule	Eligibility Criteria	Frequency of Rule Application
Start Date	Projects must be submitted for listing no more than 6 months after the project start date	Once during initial verification
Location	United States and its territories	Once during initial verification
Performance Standard	▪ Drainage projects: the project destroys CMM through any end use destruction system other than injection into a natural gas pipeline for off-site consumption ▪ All VAM projects	During initial verification of each crediting period
Legal Requirement Test	Signed Attestation of Voluntary Implementation form and monitoring procedures that lay out procedures for ascertaining and demonstrating that the project passes the Legal Requirement Test	Every verification
Regulatory Compliance	Project must be in material compliance with all applicable laws, and submit a signed Attestation of Regulatory Compliance form	Every verification
Exclusions	▪ Surface coal mines ▪ Abandoned coal mines ▪ Coal bed methane destruction ▪ Use of CO_2 or other fluid/gas to enhance methane drainage before mining takes place	Every verification

8.5 Core Verification Activities

The Coal Mine Methane Project Protocol provides explicit requirements and guidance for quantifying GHG reductions associated with the destruction of coal mine methane. The Verification Program Manual describes the core verification activities that shall be performed by verification bodies for all project verifications. They are summarized below in the context of a coal mine methane project, but verification bodies shall also follow the general guidance in the Verification Program Manual.

Verification is a risk assessment and data sampling effort designed to ensure that the risk of reporting error is assessed and addressed through appropriate sampling, testing, and review. The three core verification activities are:

1. Identifying emissions sources, sinks and reservoirs
2. Reviewing GHG management systems and estimation methodologies
3. Verifying emission reduction estimates

Identifying emission sources, sinks, and reservoirs
The verification body reviews for completeness the sources, sinks, and reservoirs identified for a project, such as VAM and CMM destruction system energy use, fuel consumption from transport of the gas, combustion and destruction from various qualifying and non-qualifying destruction devices, and emissions from the incomplete combustion of methane.

Reviewing GHG management systems and estimation methodologies
The verification body reviews and assesses the appropriateness of the methodologies and management systems that the mine operator uses to gather data on methane collected and destroyed and to calculate baseline and project emissions.

Verifying emission reduction estimates
The verification body further investigates areas that have the greatest potential for material misstatements and then confirms whether or not material misstatements have occurred. This involves site visits to the project to ensure the systems on the ground correspond to and are consistent with data provided to the verification body. In addition, the verification body recalculates a representative sample of the performance or emissions data for comparison with data reported by the project developer in order to double-check the calculations of GHG emission reductions.

8.6 Coal Mine Methane Verification Items

The following tables provide lists of items that a verification body needs to address while verifying a coal mine methane project. The tables include references to the section in the protocol where requirements are further described. The table also identifies items for which a verification body is expected to apply professional judgment during the verification process. Verification bodies are expected to use their professional judgment to confirm that protocol requirements have been met in instances where the protocol does not provide (sufficiently) prescriptive guidance. For more information on the Reserve's verification process and professional judgment, please see the Verification Program Manual.

Note: These tables shall not be viewed as a comprehensive list or plan for verification activities, but rather guidance on areas specific to coal mine methane projects that must be addressed during verification.

8.6.1 Project Eligibility and CRT Issuance

Table 8.2 lists the criteria for reasonable assurance with respect to eligibility and CRT issuance for coal mine methane projects. These requirements determine if a project is eligible to register with the Reserve and/or have CRTs issued for the reporting period. If any one requirement is not met, either the project may be determined ineligible or the GHG reductions from the reporting period (or sub-set of the reporting period) may be ineligible for issuance of CRTs, as specified in Sections 2, 3, and 6.

Table 8.2. Eligibility Verification Items

Protocol Section	Eligibility Qualification Item	Apply Professional Judgment?
2.2 - 2.2.2	Verify that the project meets the definition of a CMM project and is properly defined as either drainage project or VAM project	No
2.2.3	Confirm all non-qualifying devices have been properly accounted for within project's GHG Assessment Boundary	No
2.3	Verify ownership of the reductions by reviewing Attestation of Title	No
2.2.1 - 2.2.3, 7.1.1	If there are new destruction devices, boreholes, shafts or a project crediting period expiration at the mine, verify that project expansions have been completed, properly defined and documented to account for these changes	No
3.1	Verify that the project only consists of activities at a single coal mine or Category III gassy underground trona mine operating within the U.S. or its territories	No
3.2	Verify eligibility of project start date	No
3.2	Verify accuracy of project start date based on operational records	Yes
3.3	Verify that project is within its 10-year crediting period	No
3.4.1	Confirm execution of the Attestation of Voluntary Implementation form to demonstrate eligibility under the Legal Requirement Test	No
3.4.1	Verify that the project monitoring plan contains procedures for ascertaining and demonstrating that the project passes the Legal Requirement Test at all times	Yes
3.4.1.1	Verify that the project meets the appropriate Performance Standard Test for the project type	No
3.4.1.1	If VAM project uses supplemental CMM, verify that supplemental CMM is eligible	No
3.5	Verify that project activities comply with applicable laws by reviewing any instances of non-compliance provided by the project developer and performing a risk-based assessment to confirm the statements made by the project developer in the Attestation of Regulatory Compliance form	Yes

8.6.2 Quantification of GHG Emission Reductions

Table 8.3 lists the items that verification bodies shall include in their risk assessment and re-calculation of the project's GHG emission reductions. These quantification items inform any determination as to whether there are material and/or immaterial misstatements in the project's GHG emission reduction calculations. If there are material misstatements, the calculations must be revised before CRTs are issued.

Table 8.3. Quantification Verification Items

Protocol Section	Quantification Item	Apply Professional Judgment?
0	Verify that SSRs included in the GHG Assessment Boundary correspond to those required by the protocol and those represented in the project diagram for the reporting period	No
5.1	Verify that the project developer correctly accounted for methane destruction in the baseline scenario	No
5.1	Verify that baseline emissions for non-qualifying devices were calculated according to the protocol	No
5.1.2.1	Verify definition of mined through was properly applied to SMM boreholes	No
5.2.2	Verify NMHC concentration of CMG is either below project-specific threshold or, if above, CO_2 emissions from NMHC combustion are accounted for in project emissions	No
5.2.1	Verify that the project developer correctly quantified and aggregated electricity use	Yes
5.2.1	Verify that the project developer correctly quantified and aggregated fossil fuel use	Yes
5.2.1	Verify that the project developer correctly quantified and aggregated heat consumption	Yes
Equation 5.8, Appendix B	Verify that the project developer applied the correct emission factors for fossil fuel combustion and grid-delivered electricity	No
Equation 5.11, Appendix B	Verify that the project developer applied the correct methane destruction efficiencies	No
Equation 5.11	If the project developer used source test data in place of the default destruction efficiencies (Appendix B), verify accuracy and appropriateness of data and calculations	Yes
6.1	Verify that monitoring meets the requirements of the protocol; if it does not, verify that a variance has been approved for monitoring variations	No
6.1	Verify that NMHC samples were properly collected and analyzed	No
6.1, 6.1.1	Verify that destruction devices were operational during the reporting period, or that guidance in Section 6.1.1 was properly applied	Yes
6.2	Verify that all gas flow meters and continuous methane analyzers adhered to the inspection, cleaning, and calibration schedule specified in the protocol; if they do not, verify that a variance has been approved for monitoring variations or that adjustments have been made to data per the protocol requirements	No
6.2	Verify that any portable calibration instruments were calibrated at least annually by the manufacturer or at an ISO 17025 accredited lab	No
6.2	If any piece of equipment failed a calibration check, verify that data from that equipment was scaled according to the failed calibration procedure for the appropriate time period	No
6.3, Appendix C	If used, verify that data substitution methodology was properly applied	No
n/a	If any variances were granted, verify that variance requirements were met and properly applied	Yes

8.6.3 Risk Assessment

Verification bodies will review the following items in Table 8.4 to guide and prioritize their assessment of data used in determining eligibility and quantifying GHG emission reductions.

Table 8.4. Risk Assessment Verification Items

Protocol Section	Item that Informs Risk Assessment	Apply Professional Judgment?
6	Verify that the project monitoring plan is sufficiently rigorous to support the requirements of the protocol and proper operation of the project	Yes
6	Verify that the methane destruction equipment was operated and maintained according to manufacturer specifications	Yes
6	Verify that appropriate monitoring equipment is in place to meet the requirements of the protocol	No
6	Verify that the individual or team responsible for managing and reporting project activities are qualified to perform this function	Yes
6	Verify that appropriate training was provided to personnel assigned to project-related duties	Yes
6	Verify that all contractors are qualified for project-related duties if relied upon by the project developer. Verify that there is internal oversight to assure the quality of the contractor’s work	Yes
6	If field checks are performed by an individual that is not a third-party technician, verify the competency of the individual to perform the field check and the accuracy of the field check procedure	Yes
7.3	Verify that all required records have been retained by the project developer	No

8.7 Completing Verification

The Verification Program Manual provides detailed information and instructions for verification bodies to finalize the verification process. It describes completing a Verification Report, preparing a Verification Statement, submitting the necessary documents to the Reserve, and notifying the Reserve of the project’s verified status.

As stated in Section 8.1, project developers may choose to have a verification body conduct multiple project verifications at a single mine under a joint project verification. The verification body must verify the emission reductions entered into the Reserve system for each project and upload a unique Verification Statement for each project within the joint verification. The verification body can prepare a single Verification Report that contains information on all of the projects, but this must also be uploaded to every project under the joint verification.

9 Glossary of Terms

Active mine	Active mines include mine works that are actively ventilated by the mine operator. For the purposes of this protocol, MSHA designated "intermittent" mines are also considered active mines.
Abandoned mine	A mine where all mining activity including mine development and mineral production have ceased, mine personnel are not present in the mine workings, and mine ventilation fans are no longer operative.[27] In the U.S., mines are declared "abandoned" from the date when ventilation is discontinued.[28] This mine type is not eligible under this protocol.
Baseline emissions	Baseline emissions represent the GHG emissions within the GHG Assessment Boundary that would have occurred in the absence of the GHG reduction project.
Coal bed methane (CBM)	A generic term for methane originating in coal seams that is drained from virgin coal seams and surrounding strata. CBM is unrelated to mining activities.
Coal mine gas (CMG)	Gas from drainage systems before any processing or enrichment that often contains various levels of other components (e.g. nitrogen, oxygen carbon dioxide, hydrogen sulfide, NMHC, etc.).
Coal mine methane (CMM)	Methane contained in coal and surrounding strata that is released because of mining activity. For the purposes of this protocol, CMM also refers to the methane gas that is released because of mining activity at Category III gassy underground trona mines.
Drainage system	A term used to encompass the entirety of the equipment that is used to drain the gas from underground and collect it at a common point, such as a vacuum pumping station. In this protocol, methane drainage systems include surface pre-mining, horizontal pre-mining, and post-mining.
Eligible end use	For the purposes of this protocol, all end uses that result in the destruction/oxidation of methane except for injection into natural gas pipeline.
Gob	Also referred to as goaf, it is the collapsed area of strata produced by the removal of coal and artificial supports behind a working coalface. Strata above and below the gob are de-stressed and fractured by the mining activity.
Intermittent	Mines placed in intermittent status by MSHA, as a result of being seasonally idled for more than 90 days, are not considered abandoned. To maintain intermittent status, facilities and equipment such as the mine office, surface and underground power systems, the main mine

[27] UN Economic and Social Council, Economic Commission for Europe, Committee on Sustainable Energy, Glossary of Coal Mine Methane Terms and Definitions, July 2008.
[28] MSHA Program Policy Manual Volume V, January 2006, p.120.

	fan, and underground coal haulage systems must remain intact.[29] Under this protocol, intermittent mines are considered active mines and are eligible.
Joint project verification	Project verification option where a project developer hires a verification body to verify multiple projects at a mine.
Longwall mine	An underground mining type that uses at least one longwall panel during coal excavation.
Mine Safety and Health Administration (MSHA)	Federal enforcement agency responsible for protecting the health and safety of U.S. miners.
Mined through	When the linear distance between the endpoint of the borehole and the working face that will pass nearest the endpoint of the borehole has reached an absolute minimum. Coal mine methane from surface pre-mining boreholes shall not be quantified in the baseline until the endpoint of the borehole is mined through.
Mine	An area of land and all structures, facilities, machinery tools, equipment, shafts, slopes, tunnels, excavations, and other property, real or personal, placed upon, under, or above the surface of such land by any person, used in, or to be used in, or resulting from, the work of extracting minerals. The mine boundaries are defined by the mine area as permitted by the state in which the mine is located.
Non-qualifying destruction device	A methane destruction device that does not meet one or more of the eligibility rules as described in Section 3 (e.g. operational start date, regulatory requirement, injection into natural gas pipeline) and is located at the same mine where eligible project activities are taking place.
Oxidizer	For the purposes of this protocol, the term oxidizer refers to technology for destruction of ventilation air methane with or without utilization of thermal energy and/or with or without a catalyst.
Project diagram	A diagram of the mine that illustrates the location, quantity, and type of boreholes, ventilations shafts, eligible destruction devices and non-qualifying destruction devices within a project's GHG Assessment Boundary. The project diagram must be updated and submitted to the Reserve whenever a project expansion occurs.
Project emissions	Project emissions are actual GHG emissions that occur within the GHG Assessment Boundary as a result of project activities. Project emissions are calculated at a minimum on an annual, *ex-post* basis.
Qualifying destruction device	A methane destruction device that meets the eligibility rules for a CMM project as described in Section 3.
Room and pillar mine	An underground mining type that uses square or rectangular pillars of coal during excavation, laid out in a checkerboard fashion. Pillars typically range in size from 60 feet by 60 feet to 100 feet by 100 feet and rooms are typically 20 feet wide and a few thousand feet long

[29] MSHA Program Policy Manual, p.138.

Reporting period	Specific time period of project operation for which the project developer has calculated and reported emission reductions and is seeking verification and registration. The reporting period must be no longer than 12 months.
Standard conditions	Under this protocol, standard conditions are defined as 60ºF and 1 atm.
Ventilation air methane (VAM)	Coal mine methane that is mixed with the ventilation air in the mine that is circulated in sufficient quantity to dilute methane to low concentrations for safety reasons (typically below 1 percent).
Ventilation system	A system that is used to control the concentration of methane and other deleterious gases within mine working areas. Ventilation systems consist of powerful fans that move large volumes of air through the mine workings to dilute methane concentrations. All underground coal mines in the U.S. are required to develop and maintain ventilation systems.
Verification cycle	The Reserve requires verification of coal mine methane projects annually, but does not require verifications to be completed on specific dates. Project developers select the reporting period to be verified. Thus, each project has a unique verification cycle that begins the first time a project is verified, occurs at least annually, and ends once the crediting period expires or the project is no longer eligible, whichever happens first.
Year	For the purposes of this protocol, year refers to a 12 month period of the project's crediting period, not a calendar year.

10 References

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Appendix A Summary of Performance Standard Development

The analysis to develop the performance standard for the Coal Mine Methane Project Protocol was conducted by Science Applications International Corporation (SAIC) and was completed in May 2009. The analysis culminated in a paper that provided a performance standard recommendation to support the coal mine methane protocol development process, which the Reserve has incorporated into the protocol's eligibility rules (see Section 3).

The purpose of a performance standard is to establish a standard of performance applicable to all coal mine methane management projects that is significantly better than average greenhouse gas production for a specified service, which, if met or exceeded by a project developer, satisfies one of the criterion of "additionality."

The performance standard analysis contained an in-depth study of the following areas:

- Coal mine data trends and regional variations across the U.S.
- Degasification techniques including ventilation, surface pre-mining drainage, horizontal pre-mining drainage, and post-mining gob drainage currently used in coal mines
- Ventilation air methane utilization technologies
- Review of current, pending and anticipated regulations that could affect coal mine methane projects
- Data analysis to establish common practice for coal mine methane management at underground coal mines in the U.S.

A.1 Overview of Data Collection

The primary database used for the SAIC analysis was a coal mine methane emissions database provided by the U.S. EPA.[30] This database provided annual emissions-related data for underground mines classified as gassy by MSHA; the data cover the period 1990 through 2007. For the purposes of this analysis, the annual data for the 2000 to 2007 timeframe was used, covering a total of 295 gassy underground mines. The database provides the following data:

- Company name, mine name, and MSHA ID number
- State and county in which each mine is located
- Daily average and total methane emissions from the ventilation system, as well as the total amount of methane liberated by the mine (equal to the sum of the ventilation emissions and the drainage emissions or capture)
- An indication of whether the mine utilizes a degasification system, and if so, a brief description of the system and the total amount of methane drained through the system
- An indication as to whether the drained methane is captured, and a brief description of how the captured methane is utilized
- Detailed information on the subset of mines using methane capture

To supplement this primary data set, EPA provided a second database containing annual coal production data for the gassy mines for the years 2002 through 2006, along with an indication of

[30] This database is used as the basis for the coal mine methane emissions estimated published in EPA's annual *Inventory of U.S. Greenhouse Gas Emissions and Sinks* reports.

the mine's production status.[31] SAIC also used mine-level production data for 2000, 2001, and 2007, obtained from the Energy Information Administration (EIA).[32] SAIC merged the production data with the emissions database using each mine's MSHA identification number. The final merged dataset included 241 mines for which emissions data for at least one of the eight years in the 2000 to 2007 time frame was available.

EPA also provided a list of longwall mines in the United States that produced in excess of 750,000 tons of coal from January through September 2007, published by CoalUSA magazine. This list was supplemented by SAIC with similar CoalUSA lists for production from 2001 through 2006[33] and a table detailing the production of top non-longwall mines in 2007.[34] SAIC also consulted the mining method information contained in two EPA reports on methane recovery opportunities at gassy mines.[35] They combined the mines on these lists to create a master list of longwall mines in operation during the 2000 to 2007 time period. The master list represents a comprehensive list of longwall mines operating in and around 2007 with the following assumptions:

- The individual lists provide a comprehensive identification of all longwall mines falling above the production cutoff
- Most, if not all, longwall mines would meet the production cutoff when operating at full capacity
- Most, if not all, longwall mines would have operated at full capacity at least in one year during the 2000 to 2007 time period

All remaining mines were assigned to the room and pillar method (the other main underground coal mining method). In keeping with the industry standard definition, a longwall mine is defined as any mine that has at least one longwall face or that opened a longwall face at some point during the 2000 to 2007 period.

In combining and using the data for eight separate years into a single dataset, SAIC characterized each mine according to the furthest development of its drainage system. For example, if a mine used gob boreholes only in some years, but gob boreholes with horizontal pre-mining boreholes in other years, SAIC treated the mine as using both drainage system types during the 2000 to 2007 time frame. Similarly, mines that utilized methane in some years but not in others were treated as having utilization projects in operation in the 2000 to 2007 time frame. The decision to use and combine data for the past eight years into a single dataset was based on a trend analyses which indicated that industry practice with respect to drainage systems and utilization projects has remained fairly stable since 2000 (see Table A.1). Given

[31] EIA was the original source of the production data.
[32] EIA, http://www.eia.doe.gov/cneaf/coal/page/database.html.
[33] Weir International, Inc. 2008. "U.S. Longwall Mines – Production and Productivity: September 2007 Year to Date (Mines Producing in Excess of 750,000 tons through September)." *CoalUSA*, March 2008; Weir International, Inc. 2006. "United States Longwall Mining Statistics: 1996-July 2006." Table 2: 2006 June Year to Date U.S. Longwall Mine Production and Productivity; "Table: U.S. Longwall Production 2005," *International Longwall News*, 27 March, 2006. At: http://www.longwalls.com/sectionstory.asp?SourceID=s50; NIOSH, 2005. "Table: U.S. Longwall production 2004." *International Longwall News*, 23 March 2005; NIOSH, 2004. "Table: U.S. Longwall output 2003 now working." *International Longwall News*, 7 April 2004; NIOSH, 2003. "Table: U.S. Longwall output 2002." *International Longwall News*, 21 July 2003.
[34] Weir International, Inc. 2008. "Top 50 U.S. Underground Mines (non-longwall) – Production and Productivity: September 2007 Year to Date." *CoalUSA*, March 2008. *CoalUSA*, March 2008.
[35] U.S. EPA, *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 1999-2003* and *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 2002-2006*.

this relative stability in coal industry practices, it appeared safe to combine recent data with older data for the purpose of ascertaining current common practice.

Table A.1. Historical Trends in Mines Using Methane Drainage and Capture/Utilization

	Year							
	1990	1995	2000	2003	2004	2005	2006	2007
Mines with Drainage Systems	**33**	**25**	**21**	**18**	**21**	**24**	**21**	**20**
Mines with Gob Wells	n/a	n/a	n/a	8	11	15	12	12
Mines with Gob and Horizontal Pre-Mining Wells	n/a	n/a	n/a	3	3	3	3	3
Mines with All Three Drainage System Types	n/a	n/a	n/a	7	7	6	6	5
Mines with Capture/Use Projects	**7**	**12**	**13**	**12**	**12**	**15**	**15**	**15**
Pipeline	6	12	10	11	10	13	13	13
Electricity Generation	0	0	0	1*	1	1	1	1
Vent. Air Heating	0	0	0	1	1	1	1	1
Thermal Coal Drying	0	1*	1*	1*	1*	1*	1*	1*
Unspecified	1	0	3	0	0	0	0	0
*Mine also sells a portion of its recovered methane to a pipeline.								

Source: Developed using data in U.S. EPA, Coal 07 draft.xls file.

Trona Mines

Data on trona mines operating in the United States was also collected and examined.[36] There are four Category III gassy underground trona mines in the United States, of which two are room and pillar and two are longwall mines. The two longwall mines currently have gob wells, but neither is capturing the coal mine methane for destruction.

A.2 Summary of Analysis

Should the Performance Standard Include the Drainage System?

In order to establish the definition of a coal mine methane project, it was necessary to explore if the installation of a drainage system should be tested using a performance standard, or if the performance standard test could be limited to the installation of coal mine methane destruction devices.

The hypothesis was that federal health and safety regulations influence a coal mine operator's decision to install methane drainage systems. As stated in Section 3.4.1, there currently exists no federal, state, or local regulations requiring coal mines to reduce, limit, or control their methane emissions. Hence, based solely on a consideration of emissions regulations, all coal mine methane projects would appear to pass the regulatory test screen.

However, the situation for coal mines is complicated by the existence of federal safety regulations that govern methane concentration levels inside the mine. These safety regulations may effectively necessitate the utilization of methane drainage systems under certain gassy conditions. While there is no requirement to capture the methane emitted from such systems, to the extent that these systems may be necessitated by the safety regulations, they should not be considered a part of an additional coal mine methane project. In other words, the safety

[36] Coal Age *U.S. Longwall Census*, February 2009. MSHA ID numbers and liberation rates provided by Steven Pilling, MSHA Green River, Wyoming Field Office, June 2009. Information on drainage systems provided by Jeff Liebert, Verdeo Group, July 2009.

regulations may have important implications for determining the project definition and eligibility rules. Specifically, the methane drainage system may need to be excluded from the project definition if the system was developed as a response to the safety regulations. If this is the case, the methane drainage system does not pass the regulatory test but the methane destruction system may; the project definition should thus include only the destruction system.

To test this hypothesis, SAIC therefore conducted an analysis to determine the common practices utilized by coal mine operators to dilute methane concentrations as a function of methane liberation rates. As a first step in their data analysis, they computed arithmetic averages of the annual methane liberation data for each mine in the merged emissions dataset. However, a mine's methane emissions depend heavily on its production rate, as it is the process of removing the coal from the seam that relieves the pressure on the nearby unmined coal and surrounding strata, thereby releasing much of the gas. For this reason, the use of arithmetic average emissions data can lead to distorted results, particularly for mines that were underutilized during all or part of the 2000 to 2008 timeframe.

To correct for this possibility, SAIC developed normalized methane liberation rate estimates for the mines in the merged database for which both liberation and production data were available. Specifically, for each mine SAIC divided the sum of the 2000 through 2007 methane liberation data by the sum of the mine's 2000 through 2007 production to derive average methane liberation per ton of coal produced. They then multiplied this methane liberation rate by the largest of the eight annual production data points in the 2000 to 2007 timeframe to obtain their estimate of normalized methane liberation for the period. The year with the largest production value was used in the calculation in order to increase the likelihood that the resulting methane liberation estimate represents the mine's annual liberation rate when it is operating at full capacity. A mine operator will decide on whether or not methane drainage must be used to meet the regulatory requirements based on the expected methane liberation rate under full capacity operations.[37] Hence it is the methane liberation rate at full capacity that governs the mine operator's decision process; by computing a weighted average methane liberation value for the year in which production reaches its maximum they likewise sought to base their analysis on full capacity conditions. They used a production-normalized average rather than the actual methane liberation observed in the selected "maximum production year" because, as previously noted, the amount of methane liberated can fluctuate significantly from year to year depending on the geologic conditions encountered in each year. By using an average rather than an actual methane liberation value they reduced the potential for distortions introduced by abnormally low or high methane liberation rates in any given year.

It should be noted that production data was lacking for seven of the mines in the merged database; these mines were deleted from the database prior to proceeding with further analysis. Six of the deleted mines were room and pillar operations and hence were not a primary focus of the analysis. The single longwall mine lacking production data does not employ a drainage system.

Figure A.1 below presents a histogram of drainage system usage for the longwall mines, based on the production-normalized annual methane liberation rates for the 2000 to 2007 timeframe. This histogram indicates that the use of methane drainage is highly correlated with the quantity

[37] If the operator were to use a methane liberation estimate based on anything less than full capacity production for the purposes of deciding on the need for a drainage system, the mine would run the risk of being unable to meet the regulatory requirements when operating at full capacity.

of methane produced by a longwall mine. From these results, methane drainage can be considered a common practice for gassy longwall mines.

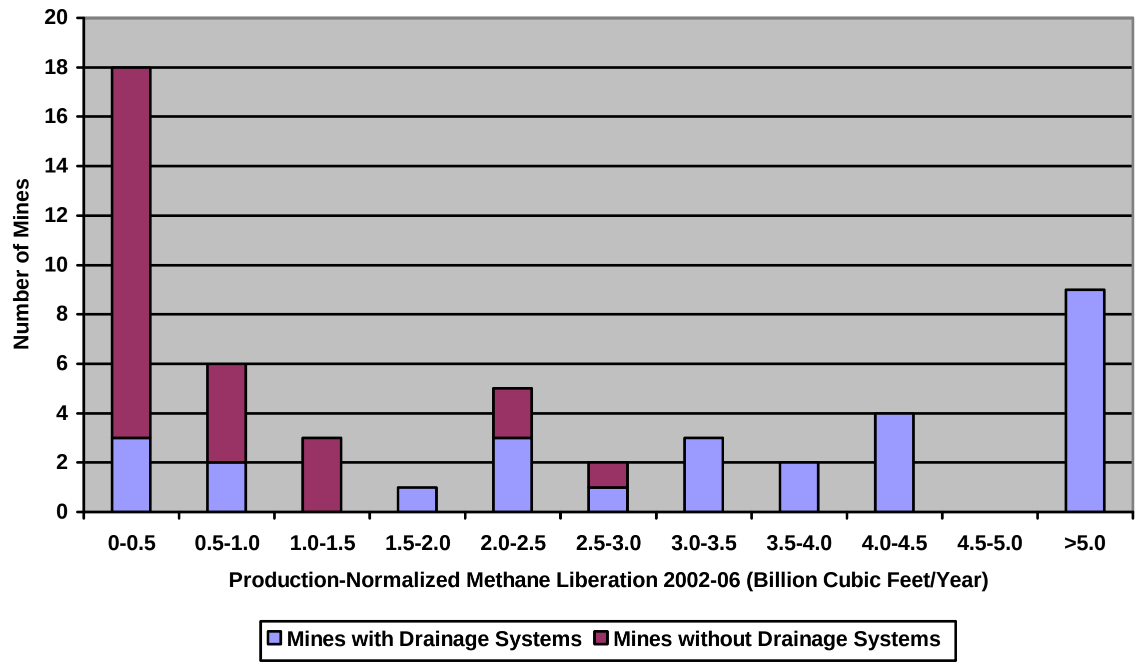

Figure A.1. Histogram of Drainage System Usage by Longwall Mines

There are currently no room and pillar mines with drainage systems in place; there are also no room and pillar mines with either arithmetic average or production-normalized methane liberation quantities in excess of two billion cubic feet.

Conclusion

This analysis strongly supports the hypothesis that the drainage systems currently in place are a response to the regulations. Given these results, we assume that all drainage systems are a response to health and safety regulations. Thus, the installation of a drainage system is not included in the definition of a coal mine methane project and is not tested for by a performance standard.

Recommendation to Use a Common Practice Standard

With the conclusion that the performance standard test must only test the additionality of the installation of a destruction device, it was necessary to determine what type of performance standard test was most suitable for coal mine methane projects.

Coal mine methane projects do not lend themselves to rate- or technology-based comparisons. In general, all coal mine methane projects are characterized by a very high rate of capture, making it difficult to distinguish projects on the basis of a metric such as methane destroyed as a percentage of methane entering the destruction device. Other potential metrics that might be used to establish a performance threshold for coal mine methane projects, such as the total quantity of methane captured on an annual basis, are fraught with difficulties. Specifically, the quantity of methane captured at any given mine is more a measure of the mine's geologic conditions than the performance of the methane capture equipment.

In general, there are no current requirements – federal, state, or local – that should influence a mine operator's choice between venting and utilizing the methane drained from drainage systems. This choice is driven by economic considerations, not regulatory requirements. A common practice standard is well-suited for these projects, in so far as common practice can help us infer whether the decision to install a methane destruction device was influenced by the availability of funding from carbon credits. Specifically, by identifying the conditions under which methane destruction is currently common practice, we can infer that projects operating under those conditions are likely undertaken to use the gas as a valuable byproduct of the mining process, and thus not additional.

Drainage Project Analysis

A strong argument can be made for determining additionality by assessing common practice of coal mine methane destruction by utilization type. As previously noted in Table A.1, only a small number of the mines with known utilization projects use the captured methane for purposes other than for sales to pipelines.

To test this hypothesis, SAIC analyzed a subset of the merged emissions/production database they created. Because the interest here is in mines that already utilize methane drainage systems, they eliminated all mines from the merged dataset that did not employ methane drainage at any time during the 2000 to 2007 timeframe. Following this elimination, they were left with a new data subset covering the 28 mines (all longwall) that employed methane drainage for at least one year during 2000 to 2007. In addition to data on the total annual amount of methane liberated in 2000 to 2007, this new database included 2000 to 2007 data on the annual amount of methane drained and vented at each of the 28 mines. The data set also provided a year-by-year indication as to whether or not all or a portion of the drained methane was captured, and the type of use to which the captured methane was applied (e.g. sales to a pipeline, electricity generation, etc.).

A close review of the database revealed anomalous methane capture indications for five of the 28 mines. Specifically, the data indicated that methane was captured at these five mines in 2002, but not in any of the subsequent years. SAIC reviewed the original EPA data file for these five mines, and found that for 1998 through 2001 the data indicated the mines were not capturing and utilizing methane. Thus the year 2002 was identified as the only year, in a ten-year period, during which methane was being captured at these five mines. In contrast, most of the other mines that practice methane capture are identified as using their capture systems in multiple years. Because of this anomaly, they treated these five mines as *not* utilizing methane capture techniques during the 2000 to 2007 timeframe, since, even if the 2002 data is correct, it appears that the mines' use of methane capture in this one year was atypical and not representative of normal practice at the five mines. In all other cases a mine identified as having employed methane capture at any time during the 2000 to 2007 timeframe was treated as a mine with a utilization project for the purposes of the analysis. See Table A.2 for a summary of this database.

Table A.2. Summary of Drainage System Type and Utilization at Longwall Coal Mines

MSHA ID	State Location	Utilization*	Drainage System Type(s)**
100851	AL	P	GHS
101247	AL	P	GHS
101322	AL	P	GHS
101401	AL	P	GHS
102901	AL	P	GH
503672	CO	H	GH
504452	CO	N	G
504591	CO	N	G
504758	CO	N	G
1514492	KY	N	U
2902170	NM	P	GH
3604281	PA	N	U
3605018	PA	P	G
3605466	PA	P	G
3605466	CO	N	G
3607230	PA	E	G
3607416	PA	N	G
4201890	UT	N	G
4202028	UT	P	G
4403795	VA	P	GHS
4404856	VA	P & TD	GHS
4601318	WV	N	GH
4601433	WV	P	GH
4601436	WV	N	GH
4601437	WV	N	G
4601456	WV	P & E	GH
4601816	WV	P	GHS
4601968	WV	P	GH

*****P = Pipeline injection
E = Electricity generation
TD = Thermal coal drying
H = Mine ventilation air heating
N = None

**G = Gob wells
H = Horizontal pre-mine wells
S = Vertical pre-mine wells
U = Unknown

Results

Analysis of the new database found that:

- Use of methane for pipeline sales is common practice, in so far as it is used at 88 percent (15 of 17) of the mines that capture methane, and 53 percent (15 of 28) of the mines that drain methane
- Use of captured methane for electricity generation is uncommon, in so far as it is limited to 12 percent of the mines that capture methane, and 7 percent of the mines that drain methane
- Use of captured methane for heating ventilation air or fueling thermal coal dryers is uncommon (limited to only 6 percent of the mines that capture methane, and 4 percent of the mines that drain methane)

- Application of captured methane to any use other than the above three is not only uncommon but non-existent

There are two possible explanations for the general lack of end-use projects other than those involving sales to pipelines. First, these projects may be generally uneconomic under current conditions. Alternatively, such projects may be economically viable, but *less so* than pipeline sales projects. Under this second interpretation, on-site projects to generate electricity, heat, etc., would be more numerous than actually observed were it not for the fact that they must compete with a generally more preferable end use—i.e. selling the CMM to a pipeline. In other words, one might hypothesize that pipeline projects are in effect distorting the analysis of common practice with respect to other end use project types, by dominating the competition between the various end use options. If true, this hypothesis would suggest that other end use project types are not generally additional, despite their rarity.

To test this hypothesis, SAIC eliminated all of the mines with pipeline sales projects from the database, and considered whether or not other end use projects are common practice within the remaining group of mines – a group for which competition from pipeline projects is not a barrier to the application of other end uses. However, before performing this analysis, it was necessary to first consider that two of the four non-pipeline projects currently in operation (an electricity generation project and a thermal coal drying project) are located at mines that *also* sell a portion of their CMM to pipelines. It appears that these two projects are not being adversely affected by competition from pipeline projects, as they co-exist with the latter. The existence of these co-located projects suggests that there may be other opportunities for the application of on-site end uses at mines that currently sell their CMM - the fact that such co-located on-site projects are uncommon indicates that these on-site applications may be sub-economic, rather than merely less economic than pipeline sales projects. It was determined that the two co-located on-site projects should be excluded from the analysis, because competition from pipeline sales projects did not prevent these two projects from being undertaken.

Focusing then on the two remaining on-site end use projects – projects which *may* not have been undertaken had pipeline sales projects been feasible at these two mines – and on the mines that are currently venting their CMM, SAIC drew the following conclusions with respect to common practice:

- Only one of the 12 mines (8 percent) that utilize drainage systems *not* connected to natural gas pipelines currently captures methane to generate electricity
- Only one of the 12 mines (8 percent) that utilize drainage systems *not* connected to natural gas pipelines currently captures methane to heat the mine ventilation air

Based on the above analysis SAIC concluded that on-site end use projects are uncommon even at mines that do not sell their CMM to pipelines. In fact, CMM end use project types other than electricity generation, ventilation air heating, and thermal coal drying are non-existent. This finding suggests that such project types are generally uneconomic under current conditions, rather than simply less economic than pipeline sales projects. Thus, even if the current pipeline sales projects did not exist, it is not clear that other project types would take their place.

The Reserve believes it is appropriate to consider the entire population of mines with drainage systems, and not just those mines that do not sell CMM to pipelines, when assessing common practice with respect to non-pipeline end use projects.

Regional Analysis

An additional analysis was conducted to assess whether common practice with respect to utilization varies across regions. Whereas common practice with respect to methane drainage is unlikely to exhibit much regional variation, given that the decision to utilize drainage techniques is often driven by *federal* regulations, the same cannot be presumed for methane utilization. On the contrary, given that the decision to initiate a capture and utilization project will generally be driven by economic criteria rather than regulations, regional variations in common practice, reflecting regional variations in the underlying economic criteria, are a real possibility that must be investigated.

Table A.3. Regional Analysis of Methane Utilization among Mines with Drainage Systems

State/Region	Mines with Normalized Methane Drainage >0.25 Billion ft^3			Mines with Normalized Methane Liberation $\leq$0.25 Billion ft^3		
	Mines with Drainage Systems	Mines with Utilization	Percent with Utilization	Mines with Drainage Systems	Mines with Utilization	Percent with Utilization
Pennsylvania	3	3	100	1	0	0
W. Virginia	6	4	67	1	0	0
Virginia	2	2	100	0	0	n/a
Kentucky	0	0	n/a	1	0	0
Alabama	5	5	100	0	0	n/a
Eastern U.S.	**16**	**14**	**87**	**3**	**0**	**0**
Colorado	3	1	33	2	0	0
Utah	1	1	100	1	0	0
New Mexico	1	1	100	0	0	n/a
Western U.S.	**5**	**3**	**60**	**3**	**0**	**0**
Total U.S.	**21**	**17**	**81**	**6**	**0**	**0**

Table A.3 presents the results of the regional analysis. It indicates little regional variation in common practice amongst mines with production-normalized methane drainage in excess of 0.25 billion cubic feet per year. Regardless of their regional location, the majority of the mines in this category captures and utilizes methane (87 percent of the eastern mines and 60 percent of the western mines). None of the six mines draining less than 0.25 billion cubic feet per year capture and utilize their CMM, regardless of mine location. Thus SAIC recommended against establishing regional variations in the common practice standards for coal mine methane projects.

Conclusion

Based on the above analysis of current utilization project types, the Reserve concluded that all projects designed to utilize the methane for any purpose other than pipeline sales shall be eligible as additional under the common practice standard. Depending on the specific utilization project type, such non-pipeline projects are rare to non-existent at present. Projects that include both pipeline sales and other uses (e.g. electricity generation) are to be treated as two separate projects for the purposes of applying the common practice standard, and the project involving uses other than pipeline sales are to be eligible under the common practice standard.
Because of similarities between the regulatory requirements, operating conditions, mining methods, and methane management of gassy underground trona mines and coal mines, the Reserve concluded the same common practice standard also applies to trona mines categorized as MSHA Category III gassy underground metal and non-metal mines.

Ventilation Air Methane Projects

There is opportunity for achieving significant reductions in coal mine methane emissions from ventilation. In 2007, the methane emissions from ventilation systems were more than 10 times greater than drainage system emissions (78.9 million cubic feet versus 7.3 million cubic feet; see Figure A.2). However, the technology available to tap into this potential market is as yet unproven commercially, at least in the U.S.

The technical barrier to the commercialization of methane destruction or utilization technology capable of being used in conjunction with ventilation systems has been the highly dilute character of the methane emitted by these systems. Typically the mine air vented from return air shafts is less than 1 percent methane. The utilization technologies considered thus far require gas with much higher methane content.

There are at present no commercial projects using ventilation air methane destruction or oxidation technology at active coal or trona mines in the United States.[38] Since commercial VAM projects are non-existent at present, the Reserve concludes that all commercial VAM projects be eligible under a common practice standard.

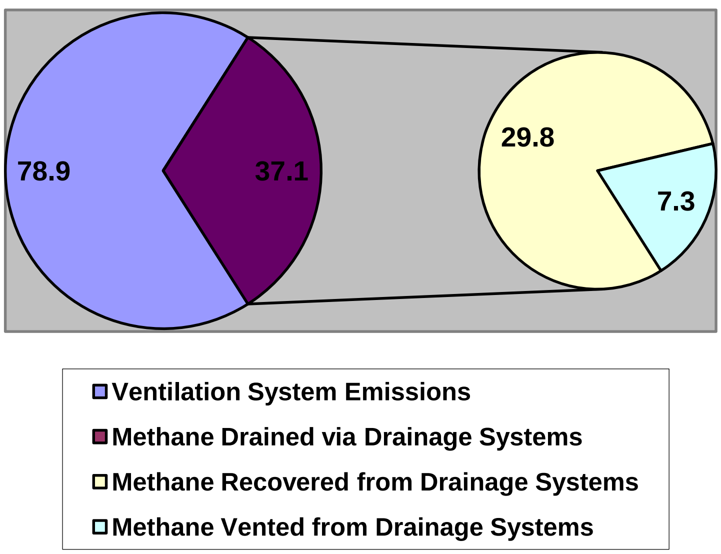

Figure A.2. Ventilation and Drainage System Emissions, 2007 (million cubic feet)

A.3 Evaluation of the Common Practice Standards

The common practice standards summarized above are based on a relatively small number of observations. However, it is important to recognize that this is not a "small sample" problem; rather it is the population of mines that uses drainage, with or without CMM utilization, which is small. With the exception of a very small number of mines with missing data that were deleted from the database, the Reserve believes the analysis covers the entire population of gassy U.S. underground mines. Although we cannot be certain that the original MSHA and EPA databases used as our primary sources provide comprehensive coverage of all gassy mines, all mines with

[38] There is one demonstration project that received approval from the Mine Health and Safety Administration (MSHA) in April 2008.

drainage, and all mines with utilization, this is the intent of these databases and we have no reason to believe that there are significant deficiencies in their coverage.

Thus, while the analysis necessarily rests on a small set of observations, it is nonetheless representative of the population. By pooling the data across eight years (2000 to 2007), SAIC was able to increase the number of mines covered in the analysis, as well as reduce the impact of short-term fluctuations in a mine's methane liberation, drainage and/or production rate on our analysis. Beyond pooling the data, there are few if any viable means of increasing the number of observations used in this analysis. We did consider the possibility of adding data from other countries, but ruled this approach out because we believe that the geologic conditions, mining methods, and economics of mining and CMM recovery are too variable across national borders to enable the application of non-U.S. data to an analysis of common practice within the U.S.

A.4 Updating the Performance Standard

The common practice standards developed for coal mine methane projects reflect operating practices under current economic, regulatory, and technological conditions. SAIC's analysis of sector trends indicated that common practice has been relatively stable or slow to evolve, at least over the past decade. If and when these conditions change in the future, the common practice standard will be affected. Therefore, the performance standard analyses will be updated on a periodic basis to either confirm that common practice has not changed or to develop new standards reflecting changed conditions.

Appendix B Emission Factor Tables

Table B.1. CO_2 Emission Factors for Fossil Fuel Use

Fuel Type	Heat Content	Carbon Content (Per Unit Energy)	Fraction Oxidized	CO_2 Emission Factor (Per Unit Energy)	CO_2 Emission Factor (Per Unit Mass or Volume)
Coal and Coke	**MMBtu / short ton**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / short ton**
Anthracite Coal	25.09	28.26	1.00	103.62	2,599.83
Bituminous Coal	24.93	25.49	1.00	93.46	2,330.04
Sub-bituminous Coal	17.25	26.48	1.00	97.09	1,674.86
Lignite	14.21	26.30	1.00	96.43	1,370.32
Unspecified (Residential/ Commercial)	22.05	26.00	1.00	95.33	2,102.29
Unspecified (Industrial Coking)	26.27	25.56	1.00	93.72	2,462.12
Unspecified (Other Industrial)	22.05	25.63	1.00	93.98	2,072.19
Unspecified (Electric Utility)	19.95	25.76	1.00	94.45	1,884.53
Coke	24.80	31.00	1.00	113.67	2,818.93
Natural Gas (By Heat Content)	**Btu / scf**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / scf**
975 to 1,000 Btu / scf	975 – 1,000	14.73	1.00	54.01	Varies
1,000 to 1,025 Btu / scf	1,000 – 1,025	14.43	1.00	52.91	Varies
1,025 to 1,050 Btu / scf	1,025 – 1,050	14.47	1.00	53.06	Varies
1,050 to 1,075 Btu / scf	1,050 – 1,075	14.58	1.00	53.46	Varies
1,075 to 1,100 Btu / scf	1,075 – 1,100	14.65	1.00	53.72	Varies
Greater than 1,100 Btu / scf	> 1,100	14.92	1.00	54.71	Varies
Weighted U.S. Average	1,029	14.47	1.00	53.06	0.0546
Petroleum Products	**MMBtu / barrel**	**kg C / MMBtu**		**kg CO_2 / MMBtu**	**kg CO_2 / gallon**
Asphalt and Road Oil	6.636	20.62	1.00	75.61	11.95
Aviation Gasoline	5.048	18.87	1.00	69.19	8.32
Distillate Fuel Oil (#1, 2, and 4)	5.825	19.95	1.00	73.15	10.15
Jet Fuel	5.670	19.33	1.00	70.88	9.57
Kerosene	5.670	19.72	1.00	72.31	9.76
LPG (average for fuel use)	3.849	17.23	1.00	63.16	5.79
Propane	3.824	17.20	1.00	63.07	5.74
Ethane	2.916	16.25	1.00	59.58	4.14
Isobutene	4.162	17.75	1.00	65.08	6.45
n-Butane	4.328	17.72	1.00	64.97	6.70
Lubricants	6.065	20.24	1.00	74.21	10.72
Motor Gasoline	5.218	19.33	1.00	70.88	8.81
Residual Fuel Oil (#5 and 6)	6.287	21.49	1.00	78.80	11.80
Crude Oil	5.800	20.33	1.00	74.54	10.29
Naphtha (<401°F)	5.248	18.14	1.00	66.51	8.31
Natural Gasoline	4.620	18.24	1.00	66.88	7.36
Other Oil (>401°F)	5.825	19.95	1.00	73.15	10.15
Pentanes Plus	4.620	18.24	1.00	66.88	7.36
Petrochemical Feedstocks	5.428	19.37	1.00	71.02	9.18
Petroleum Coke	6.024	27.85	1.00	102.12	14.65
Still Gas	6.000	17.51	1.00	64.20	9.17
Special Naphtha	5.248	19.86	1.00	72.82	9.10
Unfinished Oils	5.825	20.33	1.00	74.54	10.34
Waxes	5.537	19.81	1.00	72.64	9.58

Source: EPA Climate Leaders, Stationary Combustion Guidance (2007), Table B-2 except:
Default CO_2 emission factors (per unit energy) are calculated as: Carbon Content × Fraction Oxidized × 44/12.
Default CO_2 emission factors (per unit mass or volume) are calculated as: Heat Content x Carbon Content × Fraction Oxidized × 44/12× Conversion Factor (if applicable).
Heat content factors are based on higher heating values (HHV).

If available, the official source tested methane destruction efficiency shall be used in place of the default methane destruction efficiency. Project developers have the option to use either the default methane destruction efficiencies provided, or the site specific methane destruction efficiencies as provided by a state or local agency accredited source test service provider, for each of the combustion devices used in the project, performed on an annual basis.

Table B.2. Default Destruction Efficiencies for Combustion Devices

Destruction Device	Destruction Efficiency
Open Flare	0.96
Enclosed Flare	0.995
Lean-burn Internal Combustion Engine	0.936
Rich-burn Internal Combustion Engine	0.995
Boiler	0.98
Microturbine or Large Gas Turbine	0.995
Upgrade and Use of Gas as CNG/LNG Fuel	0.95
Upgrade and Injection into Natural Gas Pipeline	0.98**

Source: The default destruction efficiencies for enclosed flares and electricity generation devices are based on a preliminary set of actual source test data provided by the Bay Area Air Quality Management District. The default destruction efficiency values are the lesser of the twenty fifth percentile of the data provided or 0.995. These default destruction efficiencies may be updated as more source test data is made available to the Reserve.

****** The Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories gives a standard value for the fraction of carbon oxidized for gas destroyed 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 118,000kgCH_4/PJ on the basis of gas consumption, which is 0.6%. Leakage in the residential and commercial sectors is stated to be 0 to 87,000kgCH_4/PJ, which equates to 0.4%, and in industrial plants and power station the losses are 0 to 175,000kg/CH_4/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. [39]

Equation B.1. Calculating Heat Generation Emission Factor ($EF_{heat,y}$)

$$EF_{heat,y} = \frac{EF_{CO_2,i}}{Eff_{heat}} \times \frac{44}{12}$$

Where,			Units
$EF_{heat,y}$	=	Emission factor for heat generation	kg CO_2/volume
$EF_{CO2,i}$	=	CO_2 emission factor of fuel used in heat generation (see Table B.1)	kg C/volume
Eff_{heat}	=	Boiler efficiency of the heat generation (either measured efficiency, manufacturer nameplate data for efficiency, or 100%)	%
44/12	=	Carbon to carbon dioxide conversion factor	

[39] GE AES Greenhouse Gas Services, Landfill Gas Methodology, Version 1.0 (July 2007).

Appendix C Data Substitution Guidelines

This appendix provides guidance on calculating emission reductions when data integrity has been compromised due to missing data points. No data substitution is permissible for equipment such as thermocouples which monitor the proper functioning of destruction devices. Rather, the methodologies presented below are to be used only for the methane concentration and flow metering parameters, including temperature and pressure data.

The Reserve expects that projects will have continuous, uninterrupted data for the entire reporting period. However, the Reserve recognizes that unexpected events or occurrences may result in brief data gaps.

The following data substitution methodology may be used only for flow and methane concentration data gaps that are discrete, limited, non-chronic, and due to unforeseen circumstances. Data substitution can only be applied to methane concentration *or* flow readings, but not both simultaneously. If data is missing for both parameters, no reductions can be credited. The methodology may also be used for missing temperature and pressure data (which is used to adjust flow rate). However, the methodology must be applied to both parameters simultaneously, regardless of if data is available for one or the other. In other words: if either temperature or pressure data is missing, the project developer must use the following methodology to substitute data for both parameters over the same time interval.

Further, substitution may only occur when two other monitored parameters corroborate proper functioning of the destruction device and system operation within normal ranges. These two parameters must be demonstrated as follows:

1. Proper functioning can be evidenced by thermocouple readings for flares, energy output for engines, etc.
2. For methane concentration substitution, flow rates during the data gap must be consistent with normal operation.
3. For flow substitution, methane concentration rates during the data gap must be consistent with normal operations.

If corroborating parameters fail to demonstrate any of these requirements, no substitution may be employed. If the requirements above can be met, the following substitution methodology maybe applied:

Duration of Missing Data	Substitution Methodology
Less than six hours	Use the average of the four hours of normal operations immediately before and following the outage
Six to 24 hours	Use the 90% lower or upper confidence limit of the 24 hours of normal operations prior to and after the outage, whichever results in greater conservativeness
One to seven days	Use the 95% lower or upper confidence limit of the 72 hours of normal operations prior to and after the outage, whichever results in greater conservativeness
Greater than one week	No data may be substituted and no credits may be generated

The lower confidence limit should be used for both methane concentration and flow readings, as this will provide the greatest conservativeness.

CAPCOA GHG Rx Protocol:

Coastal Wetland Creation Version 1.0

(Based on the Verified Carbon Standard (VCS) Methodology Version 1.0, approved January 30, 2014)

(Approved by the CAPCOA Board on July 6, 2016)

The following conditions apply for use in the CAPCOA GHG Rx:

1. **Project must occur in California.**
2. **Include a requirement that the project must occur after January 1, 2007.**
3. **Include a requirement for a contract between the project proponent and the lead agency to ensure enforceability.**
4. **Update global warming potential factors for methane and N_2O.**
5. **Protocol relies on a buffer account to insure against reversal. Recommend approval once buffer account issue is resolved.**

Approved VCS Methodology
VM0024

Version 1.0, 30 January 2014
Sectoral Scope 14

Methodology for Coastal Wetland Creation

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Louisiana Coastal Protection and Restoration Authority

Methodology prepared by:

CH2M Hill

EcoPartners

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1 SOURCES

This methodology was developed based on the requirements in the following documents:

- *VCS Standard, v3.3*
- *AFOLU Requirements, v3.3*
- *Program Definitions, v3.4*

2 SUMMARY DESCRIPTION OF THE METHODOLOGY

Additionality and Crediting Method	
Additionality	Activity Method
Crediting Baseline	Project Method

This methodology quantifies the greenhouse gas benefits of wetland creation activities. The scope of this methodology includes two primary project activities – substrate establishment and vegetation establishment – typically implemented in combination in order to create new wetlands (ie, to restore wetlands that have degraded to open water.) The methodology also allows for implementation of either project activity individually.

The methodology also addresses the potential for the establishment of woody vegetation. As such, this methodology is categorized as a Restoring Wetland Ecosystems (RWE) + Afforestation, Reforestation and Revegetation (ARR) methodology.

This methodology is only applicable to projects located in the United States of America, as set out further in the applicability conditions.

2.1 Project Activities

Wetland creation projects must be designed such that the wetland, over time, will support the ecological processes and functions of a mature wetland habitat. If retention dikes are part of the design, natural degradation and manual breaches must be planned in order to allow for regular tidal exchange or hydrologic connectivity to the surrounding area. The created wetland must support wetland vegetation species capable of contributing to soil carbon accumulation.

The project proponent must include a plan for the establishment and maintenance of a permanent wetland plant community after project construction. The plan must provide evidence that the project area will meet the definition of a wetland upon completion of project activities (but a formal wetland delineation survey is not required). This plan may include natural colonization or manual planting or seeding of the project area. The plan also must demonstrate how the project will be maintained over the project crediting period. Maintenance requirements and activities will vary geographically due to different ecological and physical processes which may influence the project area (eg, elevation deficit vs. shoreline erosion).

Active maintenance may not be required if the created wetland is designed and constructed to offset local processes – including impaired hydrological connectivity – which may have led to the initial deterioration of the historic wetland. For instance, projects created in more protected areas may not be as susceptible to shoreline erosion forces. In addition, other non-related restoration projects near the project area may help alleviate historic issues such as nutrient and sediment source deficits. In Louisiana, for example, future planned diversions of Mississippi River water are designed to supply fresh water, nutrients, and sediment to surrounding wetlands and may influence and sustain the project area depending on proximity to and configuration with the diversion.

The project proponent must demonstrate that the project engineering and design takes into account local water level elevation, tidal range, geotechnical characteristics, sea level rise projections, and the range of plant growth within those constraints.

Monitoring Requirements: Project Activities
The monitoring report must include the following whenever substrate is established: **MRR.1** Plan for establishment of a permanent wetland plant community after project construction. Plan must include long-term monitoring of emergent vegetation and plans for continued maintenance should it become necessary. This documentation must demonstrate that the project activity results in the accumulation or maintenance of soil carbon stock and that, upon completion of the project activities, the project area must meet the definition of a wetland. **MRR.2** Evidence that the project engineering and design takes into account local water level elevation, tidal range, geotechnical characteristics, sea level rise projections, and the range of plant growth within those constraints.

2.1.1 Substrate Establishment

Wetland creation projects are formed with materials including, but not limited to, excavated or dredged sediments from waterways such as rivers, channels, canals, and embayments. Excavated sediments must be placed in open water areas to create tidal wetlands that support emergent plant establishment and growth.

The project activity of creating a wetland from open water first requires the project proponent to select a proper site location that is adjacent to a sediment source which contains a sufficient volume and is within the technical capabilities of delivering the required sediment to the project site to meet design criteria. It is common, but not required, to construct a temporary retention dike around the project area to contain the sediment material and allow for dewatering and compaction in the initial years after project construction. The temporary dike is typically constructed by machinery such as an excavator. Once complete, the project area is filled with sediment via hydraulic or mechanical dredge, pipelines, or other mechanical methods to the proper elevation as determined in the engineering and design documents based on water levels (current and projected), sediment characteristics and geotechnical analyses. The retention dikes may be designed to naturally subside to elevations which will allow for tidal exchange and hydrologic connectivity but may require manual breaches or removal after the project area sediment has consolidated to target levels.

The project proponent must provide documentation of the substrate establishment activities to demonstrate the expected post-construction conditions in the project area.

Monitoring Requirements: Substrate Establishment
The monitoring report must include the following whenever substrate is established: **MRR.3** Post-construction report, including an as-built drawing showing plan view and cross section of the project area along with an estimate of post-construction sediment elevation relative to a geodetic or tidal datum. **MRR.4** Aerial image of the project area within three years prior to construction and an aerial image within one year post-construction.

2.1.2 Vegetation Establishment

The project proponent may use natural colonization, seeding or transplantation to accomplish vegetation coverage. Depending on the time of year when the project construction is complete or the time required for substrate settlement, planting or seeding may need to occur at a future time. When seeding or transplantation occurs, the project proponent may provide a description or design drawing of post-planting or seeding, indicating the species, quantity, and photographs of the operation.

The project proponent must provide documentation of the vegetation establishment activities to demonstrate that the activities result in the accumulation or maintenance of soil carbon stock.

When the activity includes the establishment of woody vegetation, ARR+RWE requirements and methods apply to the project. Such ARR+RWE establishment activities must not include nitrogen fertilization, active peatland drainage, or lowering of the water table depth (eg, draining or construction of channels in order to harvest). Projects with an ARR+RWE component must not include commercial harvest of woody biomass; the extent of ARR requirements is limited to vegetation establishment with no management as reflected by applicability condition 6 in Section 4.

Monitoring Requirements: Vegetation Establishment
The monitoring report must include the following whenever vegetation is established: **MRR.5** A description of the quantity, species, date and location of vegetation establishment, and photographs of the operation. **MRR.6** Aerial image of the project area indicating where species were established.

2.2 Application Overview

If the project meets the applicability conditions of this methodology (see Section 4), the project proponent must follow five steps to ensure that the design of the project activities and monitoring methods meet the requirements of this methodology. Upon completion of the final step, emissions reductions and/or removals are quantified.

2.2.1 Step One: Define the Project

The first step is to identify the boundary of the project area in accordance with Section 5, following the current VCS requirements for RWE project activities. Selecting GHG sources may require an *ex-ante* analysis of expected emissions reductions and/or removals from project activities to determine *de minimis* sources (see Section 8.4.3). The project area is the location where project activities will be implemented, defined in Section 5.3.

2.2.2 Step Two: Characterize Baseline

In this step, the project proponent uses Section 6 to demonstrate that the project area would have remained as open water (see applicability condition 3) and whether dredging would have occurred in the baseline scenario. It is possible that dredging would not have occurred in the baseline scenario, which is allowed by this methodology. In the case where dredging would have occurred in the baseline scenario, emissions from energy consumption must be quantified (see Section 8.1.1).

2.2.3 Step Three: Plan Project and Monitoring Activities

Project activities must adhere to the requirements established in Section 2.1. Monitoring activities must be designed in accordance with Section 9 and are documented in a monitoring plan. Methods for monitoring are described in Appendices A, B, C, D and E. The use of any different methods must be justified by the project proponent as a methodology deviation, in accordance with the VCS rules.

The project proponent determines which sources are *de minimis*, if any, prior to validation (see Sections 8.4.3.1 and 8.4.3.2).

2.2.4 Step Four: Implement Project Activities

The project must be implemented in accordance with the validated project description. If the project is a grouped project, project activities may be implemented as separate project activity instances rather than as a single project activity instance (see Section 9.5).

2.2.5 Step Five: Monitor and Report

During and after the implementation of project activities, the project proponent must use the monitoring plan as the basis for determining emissions reductions and/or removals (see Section 9). For carbon stocks, all plots must be measured prior to the first verification event. The data from monitoring are used in Section 8.

For grouped projects, there are additional monitoring requirements (see Section 9.5). New project activity instances may require modifications to the monitoring plan.

2.3 Notation

The notation used in this methodology is meant to communicate the variables and mathematical processes used to quantify carbon stock, gas fluxes, and greenhouse gas emission reductions over time.

2.3.1 Equations

Equations in this methodology are bracketed (eg, [G.1] in-text) and the full equations are located in Appendix G. Equations in Appendix G contain additional information including citations, literature sources and comments.

At times, similar operations are performed in multiple places on different variables. Rather than repeating nearly identical equations, a single, generic equation with the placeholder x or y is given. To estimate each pool or GHG source, the relevant variable or equation may be substituted for x as indicated within the methodology.

2.3.2 Variables

Variables in this methodology and their units are enumerated in the list of variables in Appendix J. For most of these variables, their units are in tonnes of carbon dioxide equivalents. The variables x and y (with and without subscripts) are sometimes used as placeholder variables — they may stand in for another variable or the results of an equation as indicated by the methodology text.

2.3.2.1 Variable, Subscript and Superscript Designations

Some variables are noted with special designations that allow the reader to immediately identify important information about the variable. The absence of designations also implies information about the variable.

The types of designations are given in Table 1, with examples of the use of these designations given in Section 2.2.3.2. Designations are only provided for variables in Sections 8 and 9.

Table 1: Variable designations and designation descriptions

Designation	Description
Quantity	The type of quantity that the variable represents (see Sections 2.3.6, 2.3.9, 2.3.10, 2.3.11, 2.3.12 and 2.3.15).
Accounting Level	The type of accounting level implies that the variable is part of monitoring.
Change	If the Δ symbol is designated, then the quantity represents a change over a monitoring period rather than cumulative since the project start date. The absence of a change designation implies that the quantity is cumulative since the project start date or that the quantity is part of monitoring which may not be cumulative or over the monitoring period.
Source	The type of source is specified as an acronym in Section 3.1. The absence of source implies that the variable is part of monitoring or that the variable is from multiple sources.
Period	The reference to a monitoring period (see Section 2.3.7).
Index	The reference to a unit.

2.3.2.2 Designation Examples

Tables 2, 3, 4, 5 and 6 provide example variables with designations and designation descriptions.

Table 2: Example variables with designations and designation descriptions

$E_{B\,\Delta\,EC}^{[m]}$		
Component	Designation	Description
E	Quantity	This indicates an emission or an emission reduction and/or removal (see Section 2.3.14). Uppercase means the unit is a total for the project area.
B	Accounting Level	Indicates the emission or an emission reduction and/or removal occurred in the baseline scenario (see definition for P).
Δ	Change	The emission or emission reduction and/or removal is for a period of time.
EC	Source	The emission or emission reduction and/or removal is from energy consumption.
$[m]$	Period	This emission or emission reduction and/or removal is from the monitoring period.

Table 3: Example variables with designations and designation descriptions

$F_{P\,\Delta\,CH4}^{[m-1]}$		
Component	Designation	Description
F	Quantity	This indicates a flux (see Section 2.3.11). Uppercase means the unit is a total for the project area.
P	Accounting Level	Indicates the flux is as a result of the project.
Δ	Change	The flux is for a period of time.
$CH4$	Source	The flux is for methane.
$[m-1]$	Period	This flux is for the prior monitoring period.

Table 4: Example variables with designations and designation descriptions*

$E_{GER\,\Delta}^{[m=1]}$		
Component	Designation	Description
E	Quantity	This indicates an emission or an emission reduction and/or removal (see Section 2.3.14). Uppercase means the unit is a total for the project area.
GER	Accounting Level	The emission or an emission reduction and/or removal constitutes the Gross Emission Reductions (see definition for GERs).
Δ	Change	The emission or emission reduction and/or removal is for a period of time.
$[m=1]$	Period	The emission or emission reduction and/or removal is for the first monitoring period.

*Note that the absence of a P, B or L in the example given in Table 4 above indicates the emission or emission reduction and/or removal is not specific to the project, baseline or leakage.

Table 5: Example variables with designations and designation descriptions*

$E_{NER}^{[m]}$		
Component	Designation	Description
E	Quantity	This indicates an emission or emission reduction and/or removal (see Section 2.3.14). Uppercase means the unit is a total for the project area.
NER	Accounting Level	The emission or emission reduction and/or removal is constitutes the Net Emission Reductions (see definition for NERs).
$[m]$	Period	This emission or emission reduction and/or removal is for the monitoring period.

*Note that the absence of a P, B or L indicates the emission or emission reduction and/or removal is not specific to the project, baseline or leakage. The absence of a Δ indicates the emission or emission reduction and/or removal is not over a period of time, but rather cumulative since the project start date.

Table 6: Example variables with designations and designation descriptions*

$g_{B\ (ty)}^{[m]}$		
Component	Designation	Description
g	Quantity	This indicates a unit of energy (see Section 2.3.12). Lower-case means the unit is per metric tonne of sediment.
B	Accounting Level	Indicates the unit of energy would have resulted in the baseline (see definition for P)
(ty)	Index	The unit of energy is for type ty. The parentheses indicate that ty is an index rather than a designation (such as *P* for project scenario).
$[m]$	Period	This unit of energy is for the monitoring period.

*Note that the absence of a Δ indicates the unit of energy is not over a period of time, but rather cumulative since the project start date.

2.3.3 Summations

Summations use set notation. Sets of variables are indicated using script notation, which reduces the number of variables used as well as the complexity of summations.

2.3.4 Standard Deviations and Variances

Standard deviation is indicated by the σ symbol, with subscripts used to indicate the quantity for which it is estimated. Variance is indicated by the σ^2 symbol and is the square of standard deviation. Standard deviations may not necessarily be in units of tCO_2e.

2.3.5 Standard Errors

Estimated standard error is indicated by the U symbol, with additional subscripts used to indicate the quantity for which the uncertainty is estimated. Standard errors are always in units of tCO_2e.

2.3.6 Theoretical Parameters and Parameterized Models

Parameters to model are denoted by variables, such as the surface friction velocity parameter u_*. When such parameters have a "hat" on them – such as the parameter $\hat{p}_{B\ (ty)}$– they refer to an estimated value rather than a known quantity.

2.3.7 Monitoring Periods

Monitoring periods are notated using bracketed superscripts $[m]$. The first monitoring period is denoted by $[m = 1]$, the second monitoring period $[m = 2]$, and so forth. These superscripts should not be confused with references to equations numbers, as equation numbers are never in superscript. Also see the definition for monitoring period. A verification event is the reporting and verification of NERs claimed for a monitoring period. A monitoring period that is $[m = 0]$ denotes "prior to the project start date."

2.3.8 Baseline, Project and Leakage Estimates

Estimates related to baseline, project and leakage emissions reductions and/or removals and carbon stocks are specifically denoted with B, P and L in the subscripts of variables, respectively.

2.3.9 Averages for Stocks

Average carbon (measured in tCO_2e/ha) to which accounting is applied is denoted by a lower-case c, with subscripts to differentiate between carbon pools as indicated in the list of variables. For example, $c_{P\ SOC}^{[m]}$ indicates the average carbon stock in soil organic carbon in the project area in monitoring period $[m]$. Subscripts from carbon pools are acronyms listed in Section 3.1.

2.3.10 Totals for Stocks

Total carbon (measured by tCO_2e) to which accounting is applied is denoted by a capital C, with subscripts to differentiate between carbon pools as indicated in the list of variables. Subscripts from carbon pools are acronyms listed in Section 3.1.

2.3.11 Fluxes for Methane and Nitrous Oxide

Fluxes are expressed in units of tCO_2e per day by the variable F with subscripts to differentiate between GHG sources as indicated in the list of variables. Fluxes always contain a Δ in the subscript when the flux emissions are over the monitoring period. For example, $F^{[m]}_{P\,\Delta\,CH4}$ indicates the methane flux in the project area in monitoring period $[m]$. Subscripts from GHG sources are acronyms listed in Section 3.1. Some equations in Appendices B and C use a lower-case f, signifying that the units are tCO_2e per acre per day. It is important to note that although the units for fluxes are in tCO_2e per day, this does not imply that monitored fluxes have a daily resolution. Monitoring may be periodic or seasonal, as per Section 9.2.2.4.1.

2.3.12 Units of Energy or Fuel

Energy or fuel consumption is expressed as a total or per different units as specified in Table 10, denoted by a capital G for a total and a lower-case g per unit (which may be metric tonne of sediment). For example, $G^{[m]}_{P\,\Delta\,FC\,(ty)}$ indicates the total project energy consumption for energy type (ty) during monitoring period $[m]$.

2.3.13 Masses of Sediment

Sediment transport is used to estimate energy consumption in Section 8.1.1, denoted over a monitoring period as a total with an uppercase M. For example, $M^{[m]}_{P\,\Delta}$ indicates the total sediment transport as a result of project activities during monitoring period $[m]$. Masses of sediment are always quantified as metric tonnes.

2.3.14 Emissions Reductions and/or Removals

Total emissions reductions and/or removals (measured as tCO_2e) from accounting are denoted by a capital E, with subscripts to differentiate between carbon pools as indicated in the list of variables. For example, $E^{[m]}_{P\,\Delta}$ indicates the project emissions reductions and/or removals during monitoring period $[m]$. Subscripts from carbon pools and GHG sources are acronyms listed in Section 3.1.

Emissions are represented by negative E values, while emissions removals are represented by positive E values.

2.3.15 Quantified Uncertainties

Uncertainties in major carbon pools or fluxes are expressed as standard error of a total (measured by tCO_2e or tCO_2e/day, respectively) and are denoted using a capital letter U. For example, $U^{[m]}_{P\,\Delta\,CS}$ is used to indicate the uncertainty in estimated carbon stocks at monitoring period $[m]$. Because this methodology's gas flux measurement methods (described in Appendix B and Appendix C) are inherently conservative, no uncertainty is calculated for methane and nitrous oxide gas fluxes. Thus, uncertainties are calculated for carbon stock estimates only.

2.4 Documentation Requirements

2.4.1 Project Description Requirements

To ensure the project meets the requirements set out in the methodology, this methodology includes Project Description Requirements (PDRs). The project proponent must provide evidence and documentation for each PDR. PDRs are listed in each section of this methodology and in Appendix K.

Project proponents must note that in addition to the PDRs set out in this methodology, the project must adhere to all VCS rules when applying this methodology (ie, the PDRs cover all the requirements of the methodology, but they do not necessarily cover each and every VCS requirement relevant to the project).

2.4.2 Monitoring Report Requirements

To ensure the project's compliance with the methodology, this methodology includes Monitoring Report Requirements (MRRs). The project proponent must provide evidence and documentation for each MRR. MRRs are listed in each section of this methodology and in Appendix L.

2.5 Units versus Resolution of Emissions Reductions and/or Removals Accounting

The methodology accounts for emission reductions and/or removals using daily units in Section 8. Accounting is specified by day to facilitate intra-annual monitoring events and the verification of monitoring periods that may span more or less than exactly a single year.

Although emissions reductions and/or removals are calculated on a daily basis, they may not be measured or monitored on a daily basis. The requirements in Section 9 and in Appendices B, C, D and E specify that measurements are taken periodically throughout the monitoring period, and the duration or interval of those measurements does not need to be daily.

3 DEFINITIONS

In addition to the definitions set out in VCS document *Program Definitions*, the following definitions apply to this methodology:

Accretion Depth
Vertical measurement of accumulated soil material from $t^{[m-1]}$ to $t^{[m]}$

Baseline Emissions
For any monitoring period, baseline emissions $E_{B\,\Delta}^{[m]}$ are a sum of estimated emissions over selected carbon pools during the time between two verification events

Baseline Reevaluation
Revision of the baseline scenario which occurs every 10 years

Buffer Release
A periodic release of buffer credits from the AFOLU pooled buffer account

Chamber Sampling Type
A type of temporal sample using static chambers that is either peak, seasonal, or monthly (see Section 9.2.2.4.1)

Coarse Root
A root greater than or equal to 2 mm in diameter

Covariate
A variable possibly predictive of the outcome under study. Synonymous with the term *proxy*, as defined in VCS document *Program Definitions*

de minimis
Considered a negligible source of emissions (<5% of total GHG benefit generated by the project) and therefore not accounted for (see Section 8.4.3)

Degraded Wetland
Area that previously met the definition of a wetland, but now no longer meets that definition due to disruptions in normal hydrological and ecological processes and linkages (ie, the wetland converted to open water, or similar degraded state, in response to impaired sediment supply, sea level rise, impaired water quality, or similar reason). A degraded wetland may include areas of open water.

Direct Measurement
A method used to quantify energy consumption by measuring the volume of fuel consumed (see Section 9.2.4.1)

Dredging
The removal or excavation of bottom sediments from an aquatic environment for the creation or maintenance of waterways

Ebullition
The sudden release to the atmosphere of bubbles of gas (usually methane) from submerged sediment

Eddy Covariance Sampling Type
A type of temporal sample using eddy covariance that is either peak periodic, peak cumulative, seasonal, or monthly (see Section 9.2.2.4.2)

Eddy Covariance
A micrometeorological technique to estimate flux of heat, water, atmospheric trace gases and pollutants that relies on turbulence to calculate fluxes

Energy Type
A type of energy listed in Table 10

Estuarine
A tidal water body or wetland with mixing of fresh and (ocean-derived) salt water, where salinity is greater than or equal to 0.5 ppt (parts per thousand) during the period of average annual low flow

Fixed Soil Sample Depth
At the time of project validation, a fixed depth for soil sampling of the original project soil is defined by the project proponent, which cannot exceed 100 cm. The only time when the fixed sample depth may be exceeded is when accretion depth is measured from $t^{[m-1]}$ to $t^{[m]}$. For any monitoring event, a total sample depth (for carbon stock) cannot exceed the pre-defined fixed soil sample depth and the accretion depth from the current and previous monitoring event.

Flux
A flow of gas into the atmosphere expressed as a rate of mass per unit time and area (accounted for in terms of tCO_2e/ac/day)

Gross GHG Emission Reductions and Removals (GERs)
Tonnes of carbon dioxide equivalent (tCO_2e) emissions that are reduced or removed from the atmosphere due to project activities, given as the difference between baseline and project emissions or emissions reductions and/or removals, minus emissions from leakage (see Sections 8.1, 8.2 and 8.3)

Herbaceous Marsh
Wetland that is periodically flooded and generally characterized by a growth of grasses, sedges, cattails and rushes

Hydrologically Connected Areas
Two or more areas which may share matter, energy, and organisms as a result of water movement

Monitoring Period
An interval of time following the project start date and designated for systematically verifying project claims of GHG emissions reductions and/or removals. Specifically, an interval of time from $t^{[m-1]}$ to $t^{[m]}$ where $t^{[m-1]} \geq 0$ (the project crediting period start date) and $t^{[m-1]} < t^{[m]}$. The length of the monitoring period is $t^{[m]} - t^{[m-1]}$ where m denotes the number of any single monitoring period and t the number of days after the project crediting period start date that is the end of the monitoring period. A monitoring period that is $[m = 0]$ denotes "prior to the project start date."

Net GHG Emission Reductions and/or Removals (NERs)
Tonnes of carbon dioxide equivalent (tCO_2e) emissions that are reduced or removed from the atmosphere due to project activities, given as GERs adjusted for certain deductions and additions (see Sections 8.4.1, 8.4.2.1 and 8.4.2.3)

Non-Tree
Vegetation such as shrubs, grasses, sedges and other herbaceous plants which does not meet the definition of a tree

Open Water
Water with 90% of its area having a depth that does not support emergent vegetation, and no more than 10% sparse vegetation. Water with dense vegetation is not considered open water.

Original Project Soil
Soil resulting from the emplacement of sediments at the project start date

Permanent Plot
A plot with fixed area and location used to repeatedly measure change in carbon stocks over time

Programmatic Dredging Project
Routine, ongoing dredging often associated with maintaining navigability

Project Area
The geographic area controlled by the project proponent where project activities are implemented

Project Emissions or Emissions Reductions and/or Removals
Project emissions or emissions reductions and/or removals for any monitoring period $[m]$ as estimated by the events of accretion, flux and energy consumption

Project Performance
A comparison of ex-post credit generation to ex-ante estimates over time

Reference Area
An area delineated by the project proponent used to estimate emissions from methane ebullition in the baseline

Sampling Period
The period of months for static chamber or eddy covariance measurement of methane flux corresponding to a sample type (see Section 9.2.2.4.2)

Single Event Dredging Project
A dredging event associated with a discrete planned project

Soil
Unconsolidated mineral or organic material on the immediate surface of the Earth that serves as a natural medium for the growth of land plants

Soil Organic Matter
The organic matter that may be found in soil, not including coarse roots

Substrate Establishment
Adding sediment to an area devoid of sediment, or to add sediment in an open water system to raise the land elevation such that emergent plants can colonize

Tree
A perennial plant containing secondary wood and that is at least three meters tall at maturity

Tidal
A water body or wetland exposed to vertical water level fluctuations corresponding to lunar-solar gravitational cycles. The area may have freshwater or saltwater characteristics (eg, freshwater riverine and lacustrine systems may experience tidal influence without ocean-derived salts).

Vegetation Establishment
The process of seeding or transplanting vegetation to the soil, or providing adequate conditions for natural plant colonization

Verification Event
The reporting and verification of NERs claimed for a monitoring period

Water Impoundment
A body of water created or stored by impoundment structures, such as dams, dikes and levees

Water Table
The surface where water pressure in the soil is equal to the atmospheric pressure

3.1 Acronyms

AG	Above ground
AGNT	Above ground non-tree
AGT	Above ground tree
ARR	Afforestation, reforestation, and revegetation
AS	Activity-shifting
B	Baseline scenario
BA	AFOLU pooled buffer account

BG	Below ground
BGNT	Below ground non-tree
BGT	Below ground tree
BR	Buffer release
CF	Carbon fraction
CH_4	Methane
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
CS	Carbon stock
CWA	Clean Water Act
EC	Energy consumption
GERs	Gross GHG Emissions Reductions and/or Removals
GHG	Greenhouse gas
GIS	Geographic Information System
GPS	Global Positioning System
L	Leakage
LQD	Liquid
ME	Market-effects
MRR	Monitoring Report Requirement
NERs	Net GHG Emission Reductions and/or Removals
NOAA	National Oceanic and Atmospheric Administration
NPDES	National Pollutant Discharge Elimination System
N_2O	Nitrous oxide
P	Project scenario
PAI	Project Activity Instance
PAIA	Project Activity Instance Area
PD	Project Description
PDR	Project Description requirement
PM	Proxy method for energy consumption
SE	Standard error

SLD	Solid
SPC	Species
U	Uncertainty
USACE	U.S. Army Corps of Engineers
USEPA	U.S. Environmental Protection Agency
USFWS	U.S. Fish and Wildlife Service
VCS	Verified Carbon Standard
VCUs	Verified Carbon Units
VVB	Validation/Verification Body
WR	Wetland restoration

4 APPLICABILITY CONDITIONS

This methodology applies to project activities that create tidal or estuarine wetlands through substrate establishment and/or vegetation establishment.

This methodology is applicable under the following conditions:

1. Project activities must include activities intended to create new wetlands in coastal ecosystems through substrate establishment, vegetation establishment, or both.
2. Project activities must not actively lower the water table depth.
3. The project area must meet the definitions of tidal or estuarine, open water, and degraded wetland before project activities are implemented and would have remained open water in the absence of the project activities (see Section 6.1).
4. The project area must be entirely within tidal or estuarine areas within the coastal zone boundary,[1] and must meet the definition of Waters of the United States,[2] excluding the Great Lakes.[3]

[1] Areas within the coastal zone boundary, as defined by each state of the US. Refer to NOAA's Ocean and Coastal Resource websites or individual coastal zone management maps: http://coastalmanagement.noaa.gov/mystate/welcome.html and http://coastalmanagement.noaa.gov/mystate/docs/StateCZBoundaries.pdf.

[2] For definition of Waters of the United States, refer to: http://www.epa.gov/region6/6en/w/watersus.htm.

[3] Great Lakes: The geographic scope does not include portions of Minnesota, Wisconsin, Michigan, Illinois, Indiana, Ohio, Pennsylvania and New York which are hydrologically connected to the Great Lakes.

6 When ARR+RWE project activities are implemented and include the establishment of woody vegetation, there must not be commercial harvest activities, nitrogen fertilization or active peatland drainage (see Section 2.1.2).

7 The project proponent must have obtained the necessary permits to demonstrate that the project will not have a significant negative impact on hydrologically connected areas (see Section 8.3.3). This applicability condition must be satisfied at validation or at the first verification event.

PD Requirements: Applicability Conditions
The project description must include the following: **PDR.1** For each applicability condition, credible evidence in the form of analysis, documentation or third-party reports to satisfy the condition.

5 PROJECT BOUNDARY

5.1 Selecting GHG Sources

The greenhouse gases included in, and excluded from, the project boundary are set out in Table 7 below.

Table 7: GHG sources

	Source	Gas	Included?	Justification/Explanation	Affected by Project?
Baseline	Dredging, transport and re-handling for navigability or maintenance	CO_2	Yes	Emitted by fuel combustion regardless of fuel type.	No
		CH_4	Yes		
		N_2O	Yes		
		Other	None		
	Methane ebullition	CO_2	No	Methane bubbling may occur in open water; the quantity thereof may be included and monitored if desired.	No
		CH_4	Optional		
		N_2O	No		
		Other	None		
Project	Dredging, transport and placement for project activities	CO_2	Yes	Emitted by fuel combustion regardless of fuel type.	Yes
		CH_4	Yes		
		N_2O	Yes		
		Other	None		
	Habitat regeneration	CO_2	Yes	Major pool considered.	Yes
		CH_4	Yes	Wetland creation may result in an increase in CH_4 emissions in comparison to the open water baseline scenario.	
		N_2O	Yes, if significant	Wetland creation may result in an increase in N_2O emissions in comparison to the open water baseline scenario.	
		Other	None		

PD Requirements: GHG Sources
The project description must include the following: **PDR.2** A list of the included and excluded GHG sources.

5.2 Selecting Carbon Pools

The carbon pools included in or excluded from the project boundary are shown in Table 8 below.

Table 8: Carbon pools

Pool	Included?	Relevant to:	Justification/Comments
Above ground tree biomass	Included	Project	Major carbon pool required by VCS *AFOLU Requirements*.
Above ground non tree biomass	Optional	Project	May be conservatively excluded.
Below ground biomass	Optional	Project	May be conservatively excluded, but recommended when applicable root-shoot ratios are available. Only applicable in forested or woody habitats, not herbaceous ones.
Litter	Excluded	-	Conservatively excluded.
Dead wood	Excluded	-	Conservatively excluded.
Soil organic carbon	Included	Project	Major carbon pool expected to increase due to project activities.
Wood products	Excluded	-	Conservatively excluded. Not expected to be a significant pool.

Optional pools may always be conservatively excluded. The baseline scenario allows for up to 10% vegetation cover (see definition of open water in Section 3), but it is conservative to exclude the CO_2 emissions that occur from the likely loss of wetlands, CH_4 emissions from ongoing biogeochemical activity in the remaining vegetation or methane ebullition that would be expected to occur in the baseline scenario. The set of selected carbon pools is denoted by $\mathcal{C}$.

PD Requirements: Carbon Pools
The project description must include the following: **PDR.3** A list of the selected and excluded carbon pools.

5.2.1 Allochthonous Carbon in Soil Organic Carbon Pool

Autochthonous carbon sequestration, resulting from the growth of vegetation in the project area, must be estimated separately from allochthonous carbon, where there is reasonable evidence that the mass of carbon that is imported to the site exceeds that which is exported. The fate of transported organic matter must be conservatively assessed, where relevant. The opposite condition also may exist, where the mass of exported carbon from the growth of vegetation as a result of project activities is greater than the mass of carbon that would be washed out to sea under baseline conditions.

5.2.1.1 Criteria for Projects Located Within Louisiana

For projects located within Louisiana, and not within the direct influence of a river diversion or river mouth, project proponents are not required to account for allochthonous carbon import because such import has been demonstrated to be negligible (see Appendix I).

Where river diversions are implemented to enhance growth and maintenance of created wetlands, and where such river diversions are designed to import substantial quantities of mineral-associated carbon, the project proponent must justify the exclusion of allochthonous carbon using the criteria listed in Section 5.2.1.2, or must quantify the carbon import per the procedures described in Section 9.2.6.

Where there exists an artificial water impoundment which affects the hydrological regime of the project area, the project proponent must justify the exclusion of allochthonous carbon using the criteria listed in Section 5.2.1.2, or must quantify the carbon import per the procedures described in Section 9.2.6.

5.2.1.2 Criteria for Projects Located Outside Louisiana

For projects located outside Louisiana, the project proponent may conservatively exclude allochthonous carbon by using publicly available regional case studies, peer-reviewed literature or regional models to justify that the import of organic matter will not cause carbon accretion estimates to be significantly overestimated. The justification and evidence must be commensurate with the justification provided in Appendix I for projects located within Louisiana. The justification must include the following evidence which must be applicable to the geomorphology of the project area:

- Description of the dominant sources of sediments with respect to external (ie, fluvial) inputs or internal (within estuary or tidal freshwater wetland) recycling.
- Proximity of the project area with respect to direct fluvial inputs or near-shore sediment sources.
- An annual mass estimate of the total carbon imported or exported from the estuary or tidal freshwater wetland where the project area is located.
- Description of the project area/region with respect to tidal energy (such as flood- or ebb-dominated) or tidal dispersive flux. Under ebb-dominated conditions, ‘outwelling’ or transfer of carbon from the tidal wetland to the ocean would be reasonably expected.

If the project proponent cannot demonstrate that allochthonous carbon sedimentation in the project area can be conservatively excluded, monitoring of allochthonous carbon must follow the methods in Section 9.2.6, where marker horizons are used to differentiate between carbon accreted in the project area as a result of project activities and allochthonous carbon imported into the project area.

PD Requirements: Allochthonous Carbon in Soil Organic Carbon Pool
For projects located outside Louisiana, the project description must include the following in order to demonstrate that allochthonous carbon import can be conservatively ignored: **PDR.4** Narrative justification that the import of organic matter will not cause carbon accretion estimates to be significantly overestimated including citations to case studies, literature or models. **PDR.5** Description of the dominant sources of sediments with respect to external (ie, fluvial) inputs or internal (within estuary or tidal freshwater wetland) recycling. **PDR.6** Proximity of the project area with respect to direct fluvial inputs or near-shore sediment sources. **PDR.7** An annual mass estimate of the total carbon imported or exported from the estuary or tidal freshwater wetland where the project is located. **PDR.8** Description of the project area with respect to tidal energy (such as flood- or ebb-dominated) or tidal dispersive flux.

5.3 Delineating Spatial Boundaries of Project Area

The spatial boundaries of the project must be delineated using GIS techniques. The project area may consist of multiple project activity instances. That is, the project area need not be spatially contiguous and may comprise one parcel or multiple adjacent or non-adjacent parcels. The project proponent must demonstrate control of the project area as described in the most recent version of the VCS *AFOLU Requirements*.

At the project start date, the entire project area must meet the definition of open water (see Section 3 for definition). The project proponent also must demonstrate that the project area meets the definition of tidal or estuarine open water wetlands which once supported emergent wetland vegetation – such as freshwater or saltwater herbaceous marsh, scrub-shrub or forest (eg, mangrove, cypress-tupelo swamp) – but which are degraded (prior to the implementation of project activities) to a flooded or subtidal condition. In order to demonstrate that the project area is located in a tidal or estuarine system, the project proponent must provide one of the following:

- Federal or state agency supporting documentation describing the project's tidal or salinity designation. For example, the National Wetland Inventory *Wetlands Mapper* provides both tidal and salinity descriptors or modifiers for the coastal areas of the United States, or

- Peer-reviewed literature showing the proximity of the project area to study areas and the evidence of tidal influence or presence of salinity greater than 0.5 ppt (parts per thousand), or
- The location of the tide gage adjacent to the project area and data which show either a discernible diurnal, semi-diurnal or mixed-tide signal; salinity greater than 0.5 ppt (parts per thousand) during the year; or evidence of a tidal datum designation (MLLW, MSL, MHHW, etc.).

Further, the project proponent must demonstrate compliance with the most current version of the VCS *AFOLU Requirements* regarding the clearing of native ecosystems.

Additionally, the project proponent must assess the hydrological connectivity of the project area to surrounding areas using the procedures described in Section 8.3.1 and demonstrate that there are no negative impacts to hydrologically connected areas and that any adjacent hydrologically connected areas are not likely to affect the GHG emissions of the project area.

Sea level rise may affect the project area by converting wetlands into shallow open water if the rate of sea level rise exceeds the rate of soil elevation gain. Because the project boundaries are fixed throughout the lifetime of the project, any lateral movement of wetlands in the project area caused by sea level rise is inherently captured by monitoring activities (see Section 9). However, given the significant potential impact of sea level rise on constructed wetlands in the coastal zone, the proponent must demonstrate that the project's spatial boundaries and wetland establishment activities have taken into account projections of future sea level rise. In particular, the project proponent must review current technical scientific literature relevant to the area (considering sources such as the most recent IPCC assessment report and peer-reviewed literature), document expected sea level rise in the vicinity of the project area, and demonstrate that wetland construction activities have been designed to withstand expected sea level rise.

In addition, the project description must include the following:

- A description of the existing natural or constructed measures for ensuring resilience to sea level rise (eg, how existing landforms or constructed features offer physical protection of the project area).
- A description of the post-construction soil surface elevation relative to mean sea level, taking into account estimated accretion, subsidence and sea level rise parameters within the project area.

After project activities commence, it is possible that one or more tidal channels will develop within the project area. Such areas must remain part of the project area and must not be excluded.

PD Requirements: Delineating Spatial Boundaries	
The project description must include the following:	
PDR.9	GIS-based maps of the project area with, at a minimum, the features listed in Section 5.3 above.
PDR.10	Documentation that the entire project area is/was open water at the project start date.
PDR.11	Evidence that the project area meets the definition of tidal or estuarine open water wetlands which once supported emergent wetland vegetation.
PDR.12	Evidence that the project area is compliant with the most current version of the VCS *AFOLU Requirements* regarding the clearing of native ecosystems.
PDR.13	If methane emissions are included in the baseline scenario, an estimate of the average water depth in the project area prior to the implementation of project activities (see Section 6.3).
PDR.14	Documentation that the project proponent has control over the project area, in accordance with the most recent version of the VCS *AFOLU Requirements*.
PDR.15	Documentation of the assessment of effects to hydrologically connected areas as further described in Section 8.3.1.
PDR.16	Documentation of projected sea level rise in the vicinity of the project area, evidence that existing landforms or constructed features are expected to withstand project sea level rise, and a description of the post-construction soil surface elevation relative to mean sea level.

5.4 Defining Temporal Project Boundaries

Temporal project boundaries define the period of time when the project area was under the control of the project proponent and are used to determine the dates at which project activities, monitoring activities, and baseline reevaluation must occur. The following temporal project boundaries must be defined:

- The project start date.
- The length of the project crediting period.
- The dates and periodicity of baseline reevaluation and monitoring periods. A baseline reevaluation after the project start date and monitoring must conform to the VCS rules.

Within six months of the project crediting period start date and prior to the first verification event, the monitoring equipment must be installed per Sections 9.2.1.1 and 9.2.2.4. Upon the project start date, records of energy consumption must be maintained per the requirements of Section 9.2.4.

For the project duration, the project proponent must reevaluate the baseline in accordance with the VCS rules (see Section 6.4).

The project proponent must document the planned duration of monitoring periods and corresponding frequency of verification events.

PD Requirements: Temporal Project Boundaries
The project description must include the following: **PDR.17** The project start date. **PDR.18** The project crediting period start date and length. **PDR.19** The date by which mandatory baseline reassessment must occur after the project start date. **PDR.20** A timeline including the first anticipated monitoring period showing when project activities will be implemented. **PDR.21** A timeline for anticipated subsequent monitoring periods.

Monitoring Requirements: Temporal Project Boundaries
The monitoring report must include the following: **MRR.7** The project start date. **MRR.8** The project crediting period start date and length. **MRR.9** Evidence of the start of monitoring per the frequency requirements described in Sections 5.4, 9.2.1.1, 9.2.2.4, and 9.2.3.4.

5.5 Grouped Projects

In addition to the requirements for grouped projects set out in the *VCS Standard*, the project proponent must establish criteria at the time of project validation that include the following:

- Landscape configuration: All project activity instances must be similar with respect to biogeochemical processes, which are affected principally by such factors as vegetation type, salinity, and presence or absence of external nitrate loading.
- Monitoring methods: In order to facilitate the consistent accounting of all project activity instances within a single project, all project activity instances must employ the same methods to monitor emissions reductions and removals (eg, direct measurement, models from literature, or proxy model) for each included GHG source. Similarly, all project activity instances must employ the same modeling assumptions and sampling protocols for the selected monitoring methods.

Additional monitoring requirements must also be followed for grouped projects, per Section 9.5.

The set of all project activity instances is denoted by $\mathcal{G}$.

PD Requirements: Grouped Projects
If grouped projects are developed, the project description must include the following, as per the requirements set out in the *VCS Standard*: **PDR.22** A list and descriptions of all enrolled project activity instances in the group at the time of validation. **PDR.23** A map of the designated geographic area within which all project activity instances in the group may be located, indicating that all instances are in the same region. **PDR.24** A list of eligibility criteria for project activity instances.

Monitoring Requirements: Grouped Projects
If grouped projects are developed, the monitoring report must include the following, as per the requirements set out in the *VCS Standard*: **MRR.10** A list and description of all project activity instances in the project. **MRR.11** A map of the boundaries of all project activity instances in the project demonstrating that all instances are in the designated geographic region.

6 PROCEDURE FOR DETERMINING THE BASELINE SCENARIO

6.1 Demonstrating the Most Plausible Baseline Scenario

The project proponent must consider a range of alternative land uses when determining the baseline scenario for both RWE and ARR+RWE projects. Possible baseline scenarios may include a continuation of open water, additional wetland loss in accordance with long-term trends, natural reestablishment of the wetland or alternative wetland reestablishment activities not associated with carbon finance. The project description must include a comparative assessment of the implementation barriers and net benefits faced by the project and its alternatives.

As per the applicability conditions, this methodology is only applicable where the following baseline scenario is identified:

> The project area must meet the definitions of tidal or estuarine, open water, and degraded wetland before project activities are implemented and would have remained open water in the absence of the project activities.

The project proponent must use one of the analysis methods described in Section 6.1.1 or 6.1.2 to demonstrate the baseline scenario.

To demonstrate that this applicability condition has been met, it is recommended that the project proponent acquire data from USGS data sets (ie, Couvillion 2012) or the U.S. Fish & Wildlife Service's National Wetlands Inventory to show that the project area historically met the definition of a wetland and thus the definition of degraded wetland. If the applicability condition is met as required under the methodology, the only possible baseline scenario is open water. To support the chosen analysis method, the project proponent also must provide evidence of long-term water level changes in the project area with minimum record length of 20 years of hydrological data (eg, water table, water level, sea level). The evidence must demonstrate the long-term nature of the documented pattern of wetland loss.

The project proponent must also demonstrate that wetland creation is unlikely to occur in the project area based upon historical evidence of land accretion and loss.

PD Requirements: Baseline Scenario
The project description must include the following: **PDR.25** Results of a comparative assessment of the implementation barriers and net benefits faced by the project and its alternatives, and justification for the most plausible baseline scenario. **PDR.26** Documentation to demonstrate that the project area previously met the definition of a wetland before converting to open water. Documentation must include hydrological data to show evidence of long-term patterns of wetland loss. **PDR.27** The selected method for demonstrating the baseline scenario in the project area (regional land use change or spatial analysis).

6.1.1 Using a Published Regional Land Use Change Analysis

The baseline scenario may be demonstrated through documentation regarding land loss rates in the hydrologic basin in which the project area is located. Documentation must be based on Landsat or other satellite or aerial imagery that shows a trend of continued land loss or static condition in the basin for a period of at least 10 years prior to the project start date or the date of baseline reevaluation (see Section 6.4). Examples include the US Geologic Survey publication 'Land Area Change in Coastal Louisiana from 1932 to 2010', or the US Fish & Wildlife Service, National Wetlands Inventory, 'Wetlands Status and Trends' report series. The documentation must be from peer-reviewed literature, government publication or third party publication and must be publicly available.

The project proponent must also identify the boundary of the project area and its proximity to any existing and/or future water management activities (eg, river diversions) which could influence the project area. If water management activities are identified (either existing or planned over the next 10 years), the project proponent must address the potential for land-building based on significant deposition of sediment in the project area in the absence of project activities. An updated figure of water management activities must also be identified in the baseline reassessment.

PD Requirements: Regional Land Use Change for Baseline Scenario
The project description must include the following: **PDR.28** A reference to the document providing evidence of continued land loss or static condition in the basin for a period of 10 years prior to the project start date. **PDR.29** A summary of the referenced document indicating where in the document the evidence is provided. **PDR.30** Documentation of water management activities (eg, river diversions) that could influence the baseline scenario.

6.1.2 Conducting a Spatial Analysis

The baseline scenario may be demonstrated using high-resolution satellite or aerial imagery that demonstrates that the area of open water (ie, non-wetland) has not decreased over time in the region surrounding the project area. Sections 6.1.2.1 and 6.1.2.2 provide guidance on conducting the analysis. For such analysis, the following requirements must be met:

- The analysis must be conducted using data from two points in time (image dates) at least ten years apart, one of which is within two years prior to the project start date or date of baseline reevaluation (see Section 6.4).
- The two image dates must be within the same three-month period of their respective years to prevent seasonal variability.
- The study region must be at least three times the size of the project area.
- The study region must be located in an area near the project area, with similar climatic and edaphic conditions.
- Cloud cover must not exceed 20% of the study region for either image date.
- Accuracy determined by error checking or ground-truthing must be at least 90%.
- The analysis must infer that the area of open water in the study region has not decreased over time via natural processes.

The region of analysis may or may not include the project area.

PD Requirements: Spatial Analysis for Baseline Scenario	
The project description must include the following:	
PDR.31	A report describing how the analysis was conducted, including data sources and dates, demonstration of conformance with the requirements listed in Section 6.1.2, and justification for the selection of the region in which the analysis was conducted.
PDR.32	A map of the region in which the analysis was conducted.
PDR.33	The quantified change in water area.

6.1.2.1 Selecting Image Type

Aerial or satellite imagery must be high-resolution or multispectral in order to accurately delineate wetland vs. open water. Multiple images from each image date may be used to increase cloud-free coverage of the study region. The analysis must consider varying water levels on land areas at the time of the imagery, and the potential impact on interpretation of imagery. Proper pre-processing techniques must be observed, such as geometric and radiometric corrections, cloud and shadow removal and reduction of haze, as needed.

6.1.2.2 Classifying and Post-Processing

Change detection analysis may be used to determine the change in water area over time. Post-processing must include error checking and ground-truthing as needed to ensure accurate land cover assessment. For further information, see the detailed maps included with the US Geologic Survey publication ‘Land Area Change in Coastal Louisiana from 1932 to 2010,’ as well as Klemas (2011) for a detailed description regarding remote sensing techniques to monitor changes in wetlands.

6.2 Determining Dredging in Baseline Scenario

In the baseline scenario, dredging may or may not occur for navigation or maintenance purposes. Dredging may include hydraulic and mechanical machinery and the methods of sediment removal and disposal may be classified as permanent or temporary (see dredging activities described in Table 9). If dredging is included in the baseline scenario, this must be clearly identified in the project description.

In large rivers or near-shore coastal environments, navigation dredging may include a combination of temporary displacement (thalweg or current disposal) and temporary open water disposal that occurs within the banks of the river or within an embayment. In the case of temporary displacement/disposal, sediments may be re-handled multiple times before permanent removal occurs. The project proponent may account for sediment re-handling. Permanent sediment removal also may occur with dredging, transportation, and disposal at open water sites or confined disposal areas (facilities).

For the baseline scenario, the process of dredging must be described based on a single event (planned project) or routine programmatic dredging. The baseline dredging must contain a description of equipment types, method of dredging/transport/disposal/re-handling, sediment volume, and energy type and energy quantity used. The documentation of dredging activities also must include a description of the likely fate of dredged sediments in the baseline, thus indicating that the sediments would not be used for wetland creation activities in the baseline scenario.

Acceptable documents for describing single event dredging projects or programmatic dredging projects may include but are not limited to a Section 10 permit (River and Harbors Act 1899), Dredge Material Management Plan (USACE) and interagency project documents that provide descriptions or authorization for project-specific or routine operations (eg, Beneficial Use of Dredge Material, BUDMAT).

Table 9: Types of dredging activities and alternative sediment fates (permanent or temporary)

	Sediment Fate	Typical Equipment	Description
Baseline	Temporary displacement	Dustpan dredge; cutterhead suction dredge; mechanical excavator	Sediments are dredged and displaced in the river/nearshore current, subject to subsequent downstream removal from the waterway. The process of temporary sediment displacement is also described as *agitation* or *thalweg disposal*.
	Temporary removal and disposal	Hopper dredge; barge; mechanical excavator	Sediments are dredged, then transported in a confined vessel and disposed of in a temporary area, subject to subsequent downstream removal from the waterway.
	Permanent disposal	Cutterhead suction dredge; hopper dredge; mechanical excavator	Permanent sediment disposal may include confined upland disposal, non-wetland beneficial use, ocean dredge material dump site.

PD Requirements: Determination of Dredging
The project description must include the following: **PDR.34** Statement regarding whether dredging is included in the baseline scenario. **PDR.35** If dredging is included in the baseline scenario, a description of the single event or programmatic dredging projects, including the likely fate of dredged sediments in the baseline scenario.

6.2.1 Determining Navigability of Dredge Site Waterway

The project proponent must demonstrate whether navigation or maintenance dredging would have occurred in the baseline. Acceptable documents for demonstrating dredging would have occurred may include but are not limited to a Section 10 permit (River and Harbors Act 1899) or Dredge Material Management Plan (USACE) or interagency project documents that provide descriptions or authorization for project-specific or routine operations (eg, Beneficial Use of Dredge Material, BUDMAT).

If navigation or maintenance dredging in the baseline cannot be demonstrated, then baseline emissions from energy consumption must be zero per Section 8.1.1.

PD Requirements: Demonstration of Navigability
The project description must include the following if navigation or maintenance dredging can be demonstrated in the baseline scenario: **PDR.36** Map of dredging activities, including justification for planned dredging locations. **PDR.37** Documents that demonstrate dredging would have occurred.

6.2.2 Determining Energy Consumption for Dredging

When dredging occurs in the baseline scenario for navigation or maintenance, the project proponent must estimate the energy types and quantities used for dredging. For each energy type in Table 10, the project proponent must estimate the unit of energy consumed per metric tonne of sediment removed from the sediment source in the baseline scenario. These estimates must be based on private industry or federal cost-engineering procedures or data. These estimates may include energy consumption from dredging, transport, disposal and re-handling of sediment. The assumptions of equipment type(s), sediment production rates, duration of operations, and conveyance distances must be used to justify these estimates.

The project proponent must use conservative assumptions when determining these estimates. In the baseline scenario, low estimates of energy consumption for dredging are more conservative than high estimates.

The set of all energy types in the baseline scenario is denoted $\mathcal{T}_{B\ EC}$ and the unit of energy consumed per metric tonne of sediment removed from the sediment source for energy type (ty) is denoted by $g_{B\ EC\ (ty)}$ (see Section 8.1.1).

PD Requirements: Determination of Baseline Energy Consumption
The project description must include the following: **PDR.38** For each energy type in Table 10, the estimate of the unit of energy consumed per metric tonne of sediment dredged. **PDR.39** Description of equipment types and method or process of sediment dredging, transport, disposal, re-handling, sediment production rates, duration of operations and conveyance distances. **PDR.40** Estimates of cumulative sediment quantity excavated and re-handled, including temporary disposal and displacement activities, if applicable. **PDR.41** Source of procedures or data on which these estimates are based.

6.3 Determining Methane Emissions in Baseline Scenario

Methane ebullition, or bubbling from sediments, sometimes occurs in open water and may increase the GHG emissions associated with the baseline scenario in which the project area remains open water. It is optional to include emissions from methane ebullition in the baseline scenario. If baseline emissions from methane ebullition are included, the project proponent must monitor such emissions in an area of open water – referred to as a reference area – located near the project area and with environmental conditions similar to those found in the project area prior to the start of wetland creation activities (see Section 6.3.1). Methane emissions must then be monitored in the reference area (see Section 9.2.7).

6.3.1 Delineating Reference Area Boundaries

If emissions from methane ebullition are included in the baseline scenario, the project proponent must define a reference area in which emissions flux from ebullition is measured and demonstrate that the reference area is similar to the project area with respect to the following criteria:

a. Hydrologically and biogeochemically similar to the project area:

   i. Must meet the definition of open water, with no soil exposed during normal tidal cycle,

ii. Must be devoid or mostly devoid of vegetation,

iii. Must exhibit similar salinity and presence or absence of tidal influence, and

iv. Must be similar with respect to presence or absence of external nitrate loading (see Section 9.2.3.1).

b. Similar landscape configuration with respect to proximity to river delta(s), specifically if the project area is not within a delta, the reference area must not be located within a delta.

c. Soil type of similar substrate to the project area as of the project start date, specifically the soils must be classified as the same *Soil Series* as reported by the USDA NRCS Soil Survey; or if the *Soil Series* is different, then the percent organic matter of the upper 30cm of soil must occur within a common range.

d. Constrained to a minimum water depth no less than the minimum depth in the project area.

Furthermore, water depth must be recorded at each sample point. The average depth of these measurements must be at least as deep as the average depth measured in the project area as of the project start date.

Measurements in the reference area are described in Section 9.2.7.

PD Requirements: Determination of Baseline Methane Emissions
The project description must include the following: **PDR.42** Description and justification for the selected reference area.

6.4 Reevaluating the Baseline Scenario

The baseline scenario must be reevaluated every ten years in accordance with the VCS rules. The baseline reevaluation must meet the requirements in Section 6.1. If new project activity instances have been added in the case of a grouped project, the reevaluation must meet the requirements in Section 6.2.

7 PROCEDURE FOR DEMONSTRATING ADDITIONALITY

This methodology uses an activity method for the demonstration of additionality. Project activities that meet the applicability conditions of this methodology (see Section 4) and demonstrate regulatory surplus are deemed as additional.

7.1 Regulatory Surplus

Project proponents must demonstrate regulatory surplus in accordance with the rules and requirements regarding regulatory surplus set out in the latest version of the *VCS Standard*.

PD Requirements: Demonstration of Project Additionality
The project description must include the following: **PDR.43** Demonstration that pertinent laws and regulations have been reviewed and that none mandate the project activities.

7.2 Positive List

The applicability conditions of this methodology represent the positive list. The project must demonstrate that it meets all of the applicability conditions, and in so doing, it is deemed as complying with the positive list.

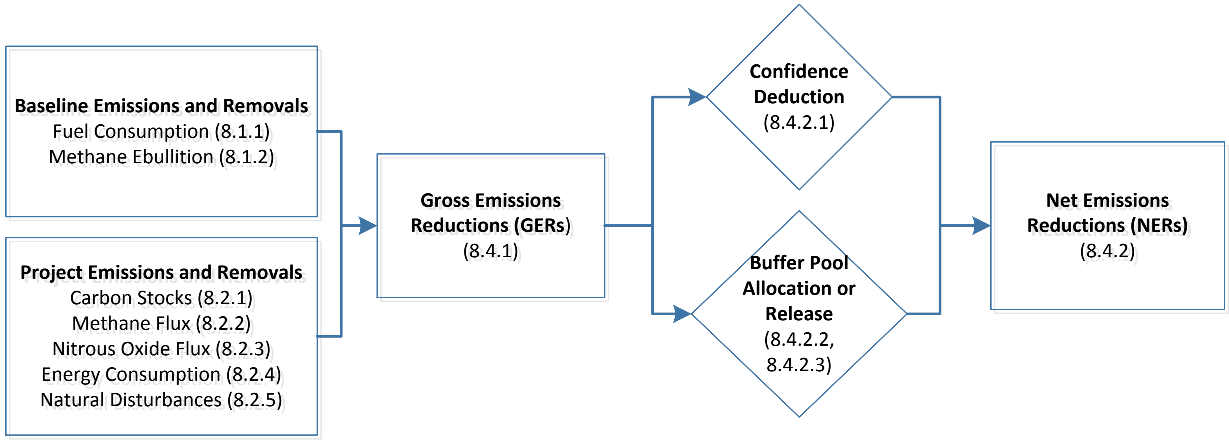
The positive list was established using the activity penetration option (Option A in the *VCS Standard*). Demonstration of additionality following this approach is set out in Appendix H – Supporting Information on Development of Positive List.

PD Requirements: Demonstration of Project Additionality
The project description must include the following: **PDR.44** Evidence that project activities comply with all applicability conditions set out under Section 4 above.

8 QUANTIFICATION OF GHG EMISSION REDUCTIONS AND REMOVALS

The project proponent must calculate gross emissions reductions and/or removals (GERs) in each monitoring period. GERs are calculated by subtracting project emissions or emissions reductions and/or removals from baseline emissions. The project proponent must then calculate net emissions reductions and/or removals (NERs) by taking into account a confidence deduction (if any) and buffer pool allocation.

Cumulative GERs and NERs are quantified as those since the project crediting period start date up to the end of the monitoring period. Current GERs and NERs are quantified as those since the end of the previous monitoring period to the end of the monitoring period.



When quantifying GHG emissions reductions and removals, the project proponent must note the difference between units and resolution of monitoring data described in Section 2.5.

8.1 Baseline Emissions

Baseline emissions $E_{B\,\Delta}^{[m]}$ for the monitoring period are given by equation [G.6], equal to the sum of baseline emissions from energy consumption and emissions from methane ebullition for the monitoring period. Note that $E_{B\,\Delta}^{[m]}$ is always less than or equal to zero.

Monitoring Requirements: Baseline Emissions
The monitoring report must include the following: **MRR.12** Calculations of current baseline emissions $E_{\mathrm{B}\,\Delta}^{[m]}$ for the (current) monitoring period. **MRR.13** Calculations of baseline emissions $E_{\mathrm{B}\,\Delta}^{[m-1]}$ for prior monitoring periods.

8.1.1 Calculating Emissions from Energy Consumption

Baseline emissions from energy consumption are given by equation [G.3] where $g_{B\,(ty)}^{[m]}$ is the energy consumed per metric tonne of sediment dredged in the baseline using energy type (ty), and $M_{P\,\Delta}^{[m]}$ is the mass of sediment dredged from the sediment source as a result of project activities during the monitoring period. Note that, since $E_{B\,\Delta\,EC}^{[m]}$ is an emission, its value is always less than or equal to zero.

The energy consumed per metric tonne of sediment dredged in the baseline is determined in Section 6.2.2. The mass of sediment dredged from the sediment source is determined each monitoring period using Section 9.2.5.

The emissions coefficients $e_{(ty)}$ for each energy type are given in Table 10. Energy emissions coefficients for fuels are defined by the EPA Final Mandatory Reporting of Greenhouse Gases Rule, while electricity emissions are determined using the most recent U.S. EPA eGRID database. For both, it is important to note that these factors are updated periodically and that the factor which is applicable for the year in which the emissions occurred must be used. Refer to Appendix M for documentation and sources of the emission coefficients listed in Table 10.

Table 10: Emissions coefficients (including CO_2, CH_4, N_2O) for energy types

Energy Type (ty)	Project Proponent Reports As:	Emission Coefficient $\boldsymbol{e_{(ty)}}$
Diesel	Gal	0.010241 tCO_2e / gal
Motor gasoline	Gal	0.008809 tCO_2e / gal
Biodiesel	Gal	0.009459 tCO_2e / gal
Compressed natural gas	Scf	0.000055 tCO_2e / scf
Electric grid	kWh	eGRID regional emission factor (tCO_2e/kWh)

Monitoring Requirements: Emissions Coefficients
The monitoring report must include the following if an emission coefficient is used for the electric grid: **MRR.14** Source and date of the emission coefficient. **MRR.15** Reference to the exact page number or worksheet cell in the source.

8.1.2 Calculating Emissions from Methane Ebullition

If baseline emissions from open water methane ebullition are included in the project accounting, these emissions $\boldsymbol{E_{B\,\Delta\,CH4}^{[m]}}$ are calculated using equation [G.5] and are expressed in units of tCO_2e. These emissions are the product of the daily flux and the number of days in the monitoring period. Note that, since $E_{B\,\Delta\,CH4}^{[m]}$ is an emission, its value is always less than or equal to zero.

8.2 Project Emissions or Emission Reductions and/or Removals

Project emissions or emission reductions and/or removals $E_{P\,\Delta}^{[m]}$ for the monitoring period are given by equation [G.15], equal to emissions or emission reductions and/or removals from change in carbon stocks, nitrous oxide, methane and energy consumption resulting from the implementation of project activities.

Project emissions will occur if the flux emissions and emissions from energy consumption are greater than carbon accretion for the monitoring period, in which case $E_{P\,\Delta}^{[m]}$ will be negative. Likewise, project emission removals will occur if carbon accretion is greater than flux emissions and emissions from energy consumption, in which case $E_{P\,\Delta}^{[m]}$ will be positive.

Monitoring Requirements: Project Emissions or Emission Reductions and/or Removals
The monitoring report must include the following: **MRR.16** Calculations of current project emissions or emissions reductions and/or removals $E_{P\,\Delta}^{[m]}$ as of the monitoring period. **MRR.17** Calculations of project emissions or emissions reductions and/or removals $E_{P\,\Delta}^{[m-1]}$ from prior monitoring periods.

8.2.1 Calculating Emission Removals in Carbon Stocks

Carbon stocks must be monitored during the project crediting period to calculate the GHG emissions or removals that occur as a result of project activities. Current emissions or emissions reductions and/or removals from carbon stocks $E_{P\,\Delta\,CS}^{[m]}$ are defined as the difference between carbon stocks from the prior monitoring period and carbon stocks from the monitoring period as given in equation [G.8] for a project that is not grouped and equation [G.9] for a grouped project; carbon stock estimates are derived from methods described in Section 9.2.1. Note that $E_{P\,\Delta\,CS}^{[m]}$ is positive if vegetation growth has occurred and carbon stocks have not been reduced by disturbances.

8.2.2 Calculating Emissions from Methane

Project emissions from methane $E_{P\,\Delta\,CH4}^{[m]}$ are calculated using equation [G.11] and are expressed in units tCO_2e. These emissions are the product of the daily flux and the number of days in the monitoring period. Note that, since $E_{P\,\Delta\,CH4}^{[m]}$ is an emission, its value is less than or equal to zero.

8.2.3 Calculating Emissions from Nitrous Oxide

Project emissions from nitrous oxide $E_{P\,\Delta\,N2O}^{[m]}$ are calculated using equation [G.13] and are expressed in units tCO_2e. These emissions are the product of the daily flux and the number of days in the monitoring period, as described in Section 9.2.2. Note that, since $E_{P\,\Delta\,N2O}^{[m]}$ is an emission, its value is less than or equal to zero.

8.2.4 Calculating Emissions from Energy Consumption

Project emissions from energy consumption are given by equation [G.14], the total energy consumed as a result of project activities. Energy use and type must be monitored per Section 9.2.4. The emissions coefficients $e_{(ty)}$ for each energy type are given in Table 10 found in Section 8.1.1. Note that, since $E_{P\,\Delta\,EC}^{[m]}$ is an emission, its value is less than or equal to zero.

8.2.5 Calculating Emissions from Disturbances

Emissions from natural disturbances and other events within the project area are inherently captured by the monitoring of carbon stocks (see Section 9.2.1). The project area must be monitored regularly for evidence of significant disturbance. The following disturbance events may be significant:

- Hurricanes
- Fires
- Marsh dieback

For guidance on how to define a significant disturbance, project proponents should refer to the definition of *loss event* in the current version of the *VCS Program Definitions.*

In the event that a significant disturbance is apparent, the project proponent must document the nature and extent of the disturbance and, if necessary, re-measure existing plots or install new plots in the disturbed area. In order to estimate these carbon stocks, the project area may need to be re-stratified per Appendix A as part of monitoring (see Section 9). If the disturbance is likely to qualify as a loss event, the loss event must be reported in accordance with VCS rules.

If re-stratification is necessary, the new strata must be effective as of the date of the disturbance, thus ensuring that the stratification accurately represents conditions in the project area.

PD Requirements: Emissions or Emissions Reductions and/or Removals Events in Project Area
The project description must include the following: **PDR.45** The selected definition of a significant disturbance.

Monitoring Requirements: Emissions or Emissions Reductions and/or Removals Events in Project Area
The monitoring report must include the following: **MRR.18** The selected definition of a significant disturbance. **MRR.19** A map of the boundaries of any significant disturbance in the project area during the monitoring period. **MRR.20** Evidence that plots were installed into these disturbed areas and were measured per Section 9.2.1.

8.3 Leakage

8.3.1 Determining Activity-Shifting Leakage

Activity-shifting leakage is zero because the project area continues to be open water in the baseline scenario, and wetland creation does not materially change the land use activities outside of the project area. Thus, leakage from shifting livestock, agricultural activities or communities cannot occur. Further, dredging emissions occur in both the baseline and project scenarios and as such are not considered as leakage emissions from machinery.

8.3.2 Determining Market-Effects Leakage

Market-effects leakage is zero as there is no commercial value to the baseline scenario of open water. As a result, no change in supply and demand can exist, nor can shift in production exist elsewhere outside of the project area.

8.3.3 Demonstrating No Ecological Leakage

As a result of adding sediment to the project area during wetland creation, the watershed-scale hydrology could be affected. These effects could cause displacement of water (either standing or flowing) to areas not inundated prior to the project start date. The project proponent must demonstrate that the project will not have a significant negative impact on hydrologically connected areas, and therefore, that there will be no ecological leakage.

In order to demonstrate that the project will not have a significant negative impact on hydrologically connected areas, the project proponent must demonstrate compliance with Section 404 of the Clean Water Act by providing an individual or general permit issued by the USACE, prior to the completion of the first verification event. Where applicable, compliance with Section 10 of the Clean Water Act (River and Harbors Act) must also be demonstrated. Likewise, any NEPA analyses and decision documents must be provided (ie, a Finding of No Significant Impact [FONSI] for an Environmental Assessment or a Record of Decision [ROD] for an Environmental Impact Statement), where applicable.

Where the project proponent demonstrates that the project will not have a significant negative impact on hydrologically connected areas in accordance with the requirements above, ecological leakage is considered to be zero.

PD Requirements: Hydrologic Effects
The project description must include the following: **PDR.46** Where possible at validation, demonstration that the project will not have a significant negative impact on hydrologically connected areas, in accordance with the requirements of Section 8.3.3.

Monitoring Requirements: Hydrologic Effects
The monitoring report must include the following: **MRR.21** Demonstration that the project will not have a significant negative impact on hydrologically connected areas, in accordance with the requirements of Section 8.3.3, where same has not already been demonstrated at validation.

8.4 Summary of GHG Emission Reduction and/or Removals

The GHG emissions reductions resulting from the project activities are quantified in two steps: Gross Emissions Reductions (GERs) and Net Emissions Reductions (NERs), Sections 8.4.1 and 8.4.2, respectively. The quantity of NERs are those that are available for retirement or sale, and are GERs minus a confidence deduction (Section 8.4.2.1) and allocation to the AFOLU pooled buffer account (Section 8.4.2.2), plus a buffer release (Section 8.4.2.3). The quantity of GERs is the difference between baseline and project emissions or emissions reductions and/or removals.

8.4.1 Quantifying Gross Emission Reductions and/or Removals

Gross Emissions Reductions (GERs) for a monitoring period $[m]$ are quantified using equation [G.16] and are equal to the total baseline emissions over the monitoring period minus the total project emissions or emissions reductions and/or removals over the monitoring period.

Monitoring Requirements: Quantification of GERs	
The monitoring report must include the following:	
MRR.22	Quantified GERs for the monitoring period including references to calculations.
MRR.23	Quantified GERs for the prior monitoring period.
MRR.24	A graph of GERs by monitoring period for all monitoring periods to date.

8.4.1.1 Handling Reversals Resulting from Energy Consumption

In the event that quantified GERs are negative – indicating that project emissions or emissions reductions and/or removals are greater than baseline emissions – and that the cause of this event is the consumption of energy by project activities, the project must not generate NERs until cumulative GERs $E_{GER}^{[m]}$ are greater than zero per equation [G.17]. Note that although cumulative GERs may be greater than zero, a reversal may still occur.

8.4.2 Quantifying Net Emissions Reduction and/or Removals

Net Emissions Reductions (NERs) are equivalent to quantified GERs less a confidence deduction (if any) and AFOLU pooled buffer account allocation. NERs generated during a monitoring period $[m]$ are determined using equation [G.21]. Quantified NERs should be rounded down to the nearest whole number.

Monitoring Requirements: Quantification of NERs	
The monitoring report must include the following:	
MRR.25	Quantified NERs for the monitoring period including references to calculations.
MRR.26	Quantified NERs for the prior monitoring period.
MRR.27	A graph of NERs by monitoring period for all monitoring periods to date.

8.4.2.1 Calculating the Confidence Deduction

The confidence deduction $E_{U\,\Delta}^{[m]}$ is given by equation [G.19] where uncertainty in the estimate of the total carbon stock is given by equation [G.18], the sum of squared-uncertainty in all selected carbon pools $\mathcal{C}$. If the monitoring plan specifies a different sampling design, equations for uncertainty will differ for biomass and soil (see Section 9).

Uncertainty is calculated solely on the basis of the carbon stock estimate and does not include uncertainty in the measurements of methane and nitrous oxide. Although estimates of methane and nitrous oxide flux are uncertain, the flux measurement methods set out in in this methodology (Sections 9.2.2 and 9.2.3) are designed to provide conservative (ie, high) estimates of project emissions or emissions reductions and/or removals from these GHG sources. Thus, the uncertainty associated with an unbiased estimate of these fluxes is expected to be negligible when compared to the intentional difference between these estimates and the true (but unknown) fluxes. Therefore, the confidence deduction does not include uncertainty from methane or nitrous oxide estimates.

The confidence deduction must be greater than or equal to zero. If the result from equation [G.19] is less than zero, the confidence deduction must be set to zero.

Monitoring Requirements: Confidence Deduction	
The monitoring report must include the following:	
MRR.28	The calculated confidence deduction and supporting calculations.
MRR.29	Any methodology deviations. Such deviations must include the text that is being modified and the proposed new language.

8.4.2.2 Determining Allocation to AFOLU pooled buffer account

The project proponent must undertake an assessment of non-permanence risks that apply to the project. This assessment must conform to current VCS requirements and must be used to determine the allocation of GERs to the AFOLU pooled buffer account. GERs allocated to the AFOLU pooled buffer account are denoted by $E_{BA\,\Delta}^{[m]}$ as given in equation [G.20] and must be based on the change in carbon stocks for the monitoring period as described in Section 8.2.1. GERs allocated to the AFOLU pooled buffer account must be rounded up to the nearest whole number.

Monitoring Requirements: AFOLU pooled buffer account	
The monitoring report must include the following:	
MRR.30	Reference to the VCS requirements used to determine the AFOLU pooled buffer account allocation.
MRR.31	Reference to calculations used to determine the AFOLU pooled buffer account allocation.

8.4.2.3 Determining Release from AFOLU pooled buffer account

Periodically, the project may be eligible for a release of credits from the AFOLU pooled buffer account. The buffer release $E_{BR\,\Delta}^{[m]}$ must be determined in accordance with VCS requirements.

Monitoring Requirements: Buffer Release	
The monitoring report must include the following:	
MRR.32	Reference to the VCS requirements used to determine the release from the AFOLU pooled buffer account.
MRR.33	Reference to calculations used to determine the buffer release.

8.4.2.4 Quantifying Vintages over a Monitoring Period

When the monitoring period spans more than one calendar year, NERs must be allocated by year, proportional to the number of calendar days in each year relative to the total number of days in the monitoring period. Quantified NERs should be rounded to the nearest whole number for each vintage year such that the sum of vintages in each monitoring period is equal to the NERs for that monitoring period.

Monitoring Requirements: Vintages
The monitoring report must include the following: **MRR.34** Quantified NERs by vintage year for the monitoring period including references to calculations.

8.4.3 Estimating Ex-Ante GHG Emission Reductions and/or Removals

To calculate ex-ante estimates of greenhouse gas reductions and removals, use the steps outlined in Section 8, substituting estimates of parameters that require monitoring with conservative estimates of those parameters derived from scientific literature or preliminary sampling as applicable. The following table lists the parameters required and provides guidance for estimating ex-ante project benefits in a conservative fashion. Note that derived quantities are not shown in this table.

Data / Parameter	Unit	Description	Ex-Ante Source of Data	Guidance for Conservative Estimation
$b^{[m]}$	Unit-less	Buffer withholding percentage calculated as required by the VCS AFOLU Non-Permanence Risk Tool	VCS AFOLU Non-Permanence Risk Tool	The non-permanence risk tool is to be applied at validation, therefore the value of $b^{[m]}$ should be known.
$C_{P\ CS}^{[m]}$	tCO_2e	Cumulative carbon stocks in project area for monitoring period	Scientific literature or preliminary sampling in areas of past wetland creation	It is conservative to underestimate carbon stocks.
$E_{P\ \Delta\ N2O}^{[m]}$	tCO_2e	Total emissions for nitrous oxide in project area over monitoring period	Select appropriate estimates from the tables given in Section 8.4.3.2	NA
$E_{P\ \Delta\ CH4}^{[m]}$, $E_{B\ \Delta\ CH4}^{[m]}$	tCO_2e	Total methane emissions in project area over monitoring period	Scientific literature or preliminary sampling	It is conservative to overestimate methane emissions in the project scenario.
$E_{BR\ \Delta}^{[m]}$	tCO_2e	Buffer release	See current VCS requirements	
$e_{(ty)}$	tCO_2e/gal	Emissions coefficient from Table 10 in Section 8.1.1 for energy type ty	Apply coefficients as given in Table 10	NA
$p_{B\ (ty)}$	unitless	Proportion of energy for energy type ty consumed in the baseline scenario	Records of past energy use for similar activities	It is conservative to assume that energy types with lower emission factors would have been used predominantly in the baseline scenario.
$p_{P\ (ty)}$	unitless	Proportion of energy for energy type ty consumed in the project scenario	Records of past energy use for similar activities	It is conservative to assume that energy types with higher emission factors would have been used predominantly in the project scenario.

Data / Parameter	Unit	Description	Ex-Ante Source of Data	Guidance for Conservative Estimation
U_s	tCO_2e	Standard error for a set of strata	Guidance from Appendix A may be used to plan sampling that is likely to meet a targeted precision level	See Appendix A

8.4.3.1 Determining Whether Emissions from Methane are *de minimis*

In systems with high salinity (>18 ppt), methane emissions may be *de minimis*. Such emissions are considered *de minimis* if, together with any other sources which may be *de minimis*, they account for less than 5% of the total GHG benefit generated by the project. The project proponent may choose one of the following methods to demonstrate that methane emissions are *de minimis*:

1. Models from literature (see Section 9.2.2.1)
2. Proxy models (see Section 9.2.2.2)
3. Direct measurements (see Section 9.2.2.3)

8.4.3.2 Determining Whether Emissions from Nitrous Oxide are *de minimis*

In systems without nitrate loading, nitrous oxide emissions may be *de minimis*. Such emissions are considered *de minimis* if, together with any other sources which may be *de minimis*, they account for less than 5% of the total GHG benefit generated by the project. The project proponent may choose one of the following methods to demonstrate that nitrous oxide emissions are *de minimis*:

1. Default factors (see Section 9.2.3.1)
2. Proxy models (see Section 9.2.3.2)
3. Direct measurements (see Section 9.2.3.3)

8.4.4 Evaluating Project Performance

Project performance must be evaluated each verification event and deviations from *ex-ante* NERs must be described. Differences in credit generation from *ex-ante* estimates may result from changes in the quality of data (literature estimates versus carbon stock estimates), changes in measurement approaches, occurrences of disturbance events or baseline re-evaluation.

Monitoring Requirements: Project Performance
The monitoring report must include the following: **MRR.35** Comparison of NERs presented for verification relative to those from *ex-ante* estimates. **MRR.36** Description of the cause and effect of differences from *ex-ante* estimates.

9 MONITORING

Project proponents must monitor the applicable GHG sources and selected carbon pools identified for the project (see Section 5.1 and Section

5.2). Table 11 provides a step-by-step summary of the monitoring program. Given that multiple GHG sources must be monitored across multiple carbon pools, it is likely that stratification of the project area will improve sampling efficiency and overall monitoring costs (see Section 9.1). Thus, stratification is performed prior to any field measurements.

The project proponent must then develop a monitoring plan to guide monitoring activities. The methods for measuring and estimating carbon stocks and gas fluxes described in the monitoring plan must adhere to the requirements provided in Section 9.2. The monitoring plan must be implemented in the first monitoring period and must guide ongoing monitoring for the duration of the project crediting period.

Using the monitoring plan as a guide, the values of data and parameters identified in Sections 9.3 and 9.4 must be reported in the project description (PD) or monitoring report (MR). When monitoring carbon stocks and fluxes, the project proponent must note the difference between accounting units (typically tCO_2e/day) and the frequency and interval monitoring activities (see Section 2.5).

Finally, grouped projects must report additional information in the Monitoring Report per Section 9.5.

Table 11: Stages of the monitoring program

Development Task	Selection of GHG sources and carbon pools →	Stratification →	Monitoring plan →	Monitoring activities
Key Activities	Identify applicable GHG sources. Select carbon pools for measurement and accounting. Determine which sources are *de minimis*, if any	Stratify project area to focus monitoring effort and reduce costs.	Develop sampling methods and procedures. Schedule dates and locations of monitoring events. Develop methods for storing, auditing and reporting monitoring data.	Perform monitoring activities. Synthesize and report monitoring data. In the event of a significant disturbance, re-stratify per Section 8.2.5 as described in Sections 9.1 and 9.2.1.2.
Section of Methodology	5.1 and 5.2	9.1 and 9.2.1.2	9.2	9.2, 9.3 and 9.4

In the case of a methodology deviation, alternative criteria and procedures relating to monitoring and measurement must still meet the requirements of Section 9.2.

9.1 Stratification

Stratification is recommended for the direct measurement of carbon stocks, and is required for the direct measurement of methane and nitrous oxide fluxes. Appendix A provides general guidelines for stratifying the project area, including guidance on allocating sampling and measurement units within strata. Different stratification systems may be used for estimating different emissions or emissions reductions and/or removals from different GHG sources.

In the case of direct measurement of carbon stocks, stratification may be used to improve sampling efficiency and thereby reduce the effort and costs associated with monitoring. In particular, stratification is likely to reduce the uncertainty of population estimates within each stratum, which often will reduce the number of plot measurements needed to meet VCS precision requirements.

For methane and nitrous oxide fluxes, stratification is used to identify the stratum that is likely to yield the greatest flux of each gas on an annual basis. The project proponent must measure the identified stratum for each gas. If desired, other strata may be measured as well.

In order to further streamline monitoring activities, in cases where the project proponent encounters a very small stratum (eg, a tidal channel that becomes established naturally within the project area), it is permissible to combine the stratum with another stratum with higher estimated emissions flux per unit of area. In the event that the very small stratum is combined with another stratum with lower estimated emissions flux per unit area, the project proponent must show that the difference in emissions is expected to be *de minimis*.

9.1.1 Multiple Flux Monitoring Methods in Strata

The project proponent may select one method for monitoring methane or nitrous oxide emissions fluxes across all strata (as described in Sections 9.2.2 and 9.2.3). Alternatively, the project proponent may choose to apply different methods to different strata.

For example, the project proponent may choose to use a well-accepted model to predict methane flux in a stratum that is well-vegetated (provided the project proponent can demonstrate the requirements of Section 9.2.2.1) and chamber measurements to directly measure methane flux elsewhere. Per Sections 9.2.1.2 and 9.2.1.3, the project proponent then allocates the chambers to the stratum and locations within the stratum that will likely yield the greatest methane flux over the course of the year.

The project proponent must clearly indicate in the monitoring plan the methods that are to be used and to which stratum each is to be applied (see Section 9.2).

The project proponent must use a stratum-area weighted average to calculate emissions fluxes for the purpose of accounting in Section 8.

9.2 Description of the Monitoring Plan

The project proponent must develop a monitoring plan to guide monitoring activities. The monitoring plan must include a description of measurement methods and procedures and an approximate schedule indicating when the project proponent will perform each monitoring activity throughout the entire project crediting period. The monitoring plan must include the following:

1. The purpose of monitoring;
2. Sampling procedures for carbon stocks and fluxes;
3. Anticipated dates and locations for sampling over a five-year period;
4. Organizational structure, responsibilities and competencies of individuals and organizations responsible for monitoring;
5. Methods for generating, recording, storing, aggregating, collating and reporting data per Sections 9.2.1, 9.2.2 and 9.2.3; and
6. Methods for internal auditing and handling of any identified non-conformities to the monitoring plan.

The schedule for monitoring activities must be based upon the guidance provided in this methodology for the frequency of measurement for the applicable GHG sources.

Table 12: Approximate schedule of monitoring activities by GHG source

<table>
<tr><th colspan="2"></th><th>First verification</th><th>Years 1-10 after first verification</th><th>Years 11 + after first verification</th></tr>
<tr><td colspan="2">Carbon stocks (9.2.1.4)</td><td>All plots measured.</td><td>All plots measured at least once. May ‘cycle’ through a portion of plots each year.</td><td>All plots measured at least once every 5 years. May ‘cycle’ through a portion of plots each year.</td></tr>
<tr><td rowspan="2">Methane</td><td>Project (9.2.2.4)</td><td>Flux measured regardless of monitoring method.</td><td colspan="2">Model from literature: No direct measurements. Assess applicability of methods at each verification event.
Proxy model: Direct measurement of covariates every monitoring period.
Direct measurement: Flux measured every year. (Chamber method: at least 2 measurement events per year; eddy covariance method: at least 21 days of measurements per year)</td></tr>
<tr><td>Baseline (9.2.7)</td><td>Flux measured regardless of monitoring method.</td><td colspan="2">(same as above)</td></tr>
<tr><td colspan="2">Nitrous oxide (9.2.3.4)</td><td>Flux measured regardless of monitoring method.</td><td colspan="2">Model from literature: No direct measurements. Assess applicability of methods at each verification event.
Proxy model: Direct measurement of covariates every monitoring period.
Direct measurement: Flux measured every year. (at least 12 measurement events; see Section 9.2.3.4)</td></tr>
</table>

PD Requirements: Monitoring Plan	
The project description must include the following:	
PDR.47	A summary of carbon stock sampling procedures for the project area, with a copy of a sampling protocol used by field personnel to carry out measurements.
PDR.48	A summary of flux measurement procedures for the project area, with a copy of a flux measurement protocol used by field personnel to carry out measurements.
PDR.49	A reference to the monitoring plan.
PDR.50	Any methodology deviations. Such deviations must include the text that is being modified and the proposed new language.

Monitoring Requirements: Monitoring Plan	
The monitoring report must include the following:	
MRR.37	Documentation of training for field measurement crews.
MRR.38	Documentation of data quality assessment.
MRR.39	References to plot allocation for carbon stock measurement.
MRR.40	List of plot geodetic coordinates for plots and flux measurement devices.
MRR.41	Description and diagram of flux measurements devices for methane and/or nitrous oxide.
MRR.42	The estimated carbon stock, standard error of the total for each stock, and the sample size for each stratum in the project area.
MRR.43	Any methodology deviations. Such deviations must include the text that is being modified and the proposed new language.
MRR.44	Frequency of monitoring for each plot and flux measurement location – all carbon stock plots must be measured for the first verification.

9.2.1 Monitoring Project Carbon Stocks

Carbon stocks must be monitored prior to the first verification, at least once within 10 years after the first verification, and at least once every 5 years thereafter, and not necessarily at every verification event. Total carbon stock for the selected carbon pools is calculated using equation [G.7].

9.2.1.1 Requirements for First Verification

At the first verification, carbon stocks prior to the project start date must be estimated, denoted as $C_P^{[m=0]}$, using equation [G.7]. If plots were not installed prior to the project start date, stratification from aerial imagery may be required to estimate $C_P^{[m=0]}$ (see Section 9.2.1.2).

All plots must be measured at the first verification.

9.2.1.2 Requirements for Stratification

Stratification may be used to improve sampling efficiency, and may be required to estimate carbon stocks prior to the first monitoring period (see Section 9.2.1.1). Appendix A provides general guidelines for stratifying the project area, including guidance on allocating measurement units within strata. For measurements of carbon stocks, some strata may not be measured if these areas can conservatively be assumed not to accumulate soil or biomass carbon stock. For example, an aerial photo may be used to delineate unproductive areas in which minimal above ground biomass has accumulated in a given monitoring period. Rather than allocating sample units to these strata, the project proponent may conservatively assume that these areas have a stock of zero, focusing sampling efforts on areas that have more substantial biomass accumulation.

Strata boundaries may change over time to improve carbon stock estimates.

PD Requirements: Stratification
The project description must include the following if stratification is not elected for either biomass or SOC: **PDR.51** Justification for not stratifying carbon stocks.

9.2.1.2.1 Stratification for SOC

When estimating soil carbon stocks, the project proponent may stratify the project area according to factors such as water depth, elevation or relative terrain position, soil type maps, or vegetation cover. A map of all identified strata and their areas must be reported as well as the allocation of plots within each stratum.

PD Requirements: Stratification for SOC
The project description must include the following if the project area is stratified: **PDR.52** Description for how the strata were delineated. **PDR.53** Map(s) of the initial strata boundaries.

Monitoring Requirements: Stratification for SOC
The monitoring report must include the following if the project area is stratified: **MRR.45** Map(s) of the current strata boundaries. **MRR.46** A description of changes to the strata boundaries (if applicable).

9.2.1.2.2 Stratification for Biomass

When estimating biomass carbon stocks, the project proponent may stratify the project area according to factors such as vegetation type; age, stocking, or vegetation density; site quality; elevation or relative terrain position. A map of all identified strata and their areas must be reported as well as the allocation of plots within each stratum.

PD Requirements: Stratification for Biomass	
The project description must include the following if the project area is stratified:	
PDR.54	Description for how the strata were delineated.
PDR.55	Map(s) of the initial strata boundaries.

Monitoring Requirements: Stratification for Biomass	
The monitoring report must include the following if the project area is stratified:	
MRR.47	Map(s) of the current strata boundaries.
MRR.48	A description of changes to the strata boundaries (if applicable)

9.2.1.3 Direct Measurement for Stock Change

The project proponent must take direct measurements of biomass and SOC. The project proponent must use the protocols prescribed in Appendix D and Appendix E as the basis for carbon stock measurement in the monitoring plan.

The project proponent must describe the methods for allocating plots to strata and within strata.

PD Requirements: Measuring Carbon Stocks	
The project description must include the following:	
PDR.56	Method for allocating plots to stratum.
PDR.57	Description of plot sizes and layout (such as the use of nests and their sizes) for each carbon pool.

Monitoring Requirements: Measuring Carbon Stocks	
The monitoring report must include the following:	
MRR.49	Method for allocating plots to stratum.
MRR.50	Map of the location of plots within strata.
MRR.51	Description of plot sizes and layout (such as the use of nests and their sizes) for each carbon pool.

9.2.1.3.1 Soil Plot Design

Permanent plots must be randomly allocated in the project area. Artificial marker horizons (feldspar or other technique) may be used to define the original project soil surface after the implementation of project activities. The project proponent must specify the maximum soil sample depth, which will be fixed for the life of the project.

PD Requirements: Soil Plot Design	
The project description must include the following:	
PDR.58	Diagram of a soil plot showing the locations of artificial marker horizons and core samples within the plot over time.
PDR.59	Description of the fixed soil sample depth.

Monitoring Requirements: Soil Plot Design	
The monitoring report must include the following:	
MRR.52	For each measured soil plot, a diagram showing the location of installed artificial marker horizons and sampled cores.
MRR.53	Field report describing soil sample depths (accretion depth and fixed soil sample depth) and coring devices used to collect samples. The report must also include number of soil samples and their identification in a chain of custody form submitted to the laboratory.

9.2.1.4 Frequency of Measurement

All plots must be measured at the first verification. For the remainder of the project crediting period, carbon stocks must be monitored at least once within the next 10 years and at least once every five years thereafter, and not necessarily at every verification event. The project proponent may choose to 'cycle' through a portion of measurement plots over the five-year period.

PD Requirements: Frequency of Carbon Stock Measurements
The project description must include the following: **PDR.60** The anticipated frequency of monitoring for each plot and flux measurement location – all carbon stock plots should be measured for the first verification.

Monitoring Requirements: Frequency of Carbon Stock Measurements
The monitoring report must include the following: **MRR.54** List of plots measured during the monitoring period – all carbon stock plots should be measured for the first verification.

9.2.2 Monitoring Project Methane Flux

In the project case, methane flux $F^{[m]}_{P\,\Delta\,CH4}$ must be monitored using one of three approaches: models taken from peer reviewed scientific literature (Section 9.2.2.1), proxy methods developed by the project proponent (Section 9.2.2.2) or direct measurement of flux from the project area (Section 9.2.2.3). All three approaches result in an estimate of flux in units of tCO_2e/day, which is then used in equation [G.11] to predict emissions as a result of project activities (see Section 8.2.2). Specific field methods for measuring methane flux are described in Appendices B and C.

In deciding which monitoring approach to use, keep in mind that direct measurement is usually the most demanding in terms of time and cost. If the project proponent is able to identify a model that meets the requirements herein, it will likely be the most efficient method.

Once an approach is selected, it cannot be changed after the first verification event unless it is being changed to direct measurement.

PD Requirements: Monitoring Methane
The project description must include the following: **PDR.61** The selected approach for monitoring methane.

9.2.2.1 Models from Literature

Methane flux may be predicted using a process model or proxy model selected from peer-reviewed scientific literature but only after the model has been demonstrated to be applicable to the project area. In selecting a model and demonstrating that it is applicable to the project area, the project proponent must do the following:

1. Provide a description of the model that includes references to key technical papers and justifies why the selected model is appropriate for predicting methane flux in the project area.
2. Enumerate the assumptions (or applicability conditions) of the model, explain how each of those assumptions is satisfied in the application of the model to the project area.
3. List all parameters of the model, providing the values applied, the source of those parameters, and providing a justification for why the selected value is appropriate to the project area. If parameters are selected by the user to calibrate the model, the project proponent must justify the values selected for these parameters conservatively predicts emissions. Modeling conducted in support of credit generation activities must use parameter values that are specific to the project area where it is possible to do so (ie, the model must be calibrated based on measurements made at the project site, not applied with default settings).
4. List any forcing variables or covariates (for example, meteorological or hydrological measureable variables available at each time step for which the model is run) that drive the model and provide a plan to obtain project area-specific values for those parameters.

At the initial project verification and at baseline reevaluation, the model's applicability must be assessed by comparison to direct field measurements of methane flux. The project proponent must do all of the following to determine if the model is applicable to the project area:

1. Directly measure methane flux for one season as described in Appendix B. The measurements must meet all assumptions outlined in Appendix B. Appendix B is designed to provide conservative (high) estimates of methane flux.
2. Use the selected and calibrated model to predict the measured methane flux independent of any data used to calibrate the model.

3. Estimate the model error as the sum of the differences between predicted and measured fluxes, divided by the number of measurements.

4. The mean error must demonstrate that the model conservatively over-predicts emissions fluxes compared to direct measurement of methane flux.

Predicted emissions fluxes by the selected model from literature must be converted to units of tCO_2e/day, such that they can be used directly in equation [G.11] as described in Section 8.2.2 (for the distinction between units and resolution, see Section 2.5).

If a model(s) from literature is selected, it must be justified at the time of validation and its applicability determined at the first verification event and subsequent baseline reevaluations.

PD Requirements: Methane Models from Literature
The project description must include the following if a model from literature is used to estimate methane flux: **PDR.62** Justification of methane flux model from the literature, per the requirements of Section 9.2.2.1.

Monitoring Requirements: Methane Models from Literature
The monitoring report must include the following if a model from literature is used to estimate methane flux: **MRR.55** Demonstration that the selected model is applicable to the project area per the requirements of Section 9.2.2.1. **MRR.56** Description of how model predictions are converted to tCO_2e/day.

9.2.2.2 Proxy Modeling

Project proponents may develop new proxy models to predict methane flux from wetland ecosystems. In building such a predictive model, the project proponent must measure or collect published data on response variables (methane flux) using the guidance in Appendix B as well as possible covariates, consider a range of alternative models and select a model using statistically sound procedures, and apply the model at each verification event to predict methane flux. Use Sections 9.2.2.2.1, 9.2.2.2.2, 9.2.2.2.3 and 9.2.2.2.4 to develop new proxy models.

Although the possible covariates to methane flux must be reported at the time of validation, the selected model and data used to fit the model must be reported at the time of the first verification event.

Such models must comply with requirements for models set out in the *VCS Standard*.

9.2.2.2.1 Considering Covariates

In developing a statistical model, project proponents should first develop a list of possible covariates and list sources of potential data for those covariates, which may include direct field measurement, remote sensing, peer-reviewed scientific literature, and technical reports completed by government agencies. Covariates to be considered may include but are not limited to soil salinity, water salinity, soil temperature, water temperature, air temperature, flooding, spectral reflectance, elevation, flooding frequency, flooding depth, soil organic carbon, and sulfate concentrations. From the initially considered covariates, identify those whose data availability and expected relationship with methane flux are most relevant to the project needs.

Possible and selected covariates and sources for covariates must be validated.

PD Requirements: Covariates for Proxy Methane Models
The project description must include the following if a proxy model is used to estimate methane flux: **PDR.63** A list of possible covariates and the sources of data available for each. **PDR.64** A list of selected covariates to be used for model fitting.

9.2.2.2.2 Collecting Data for Model Fitting and Response Variables

Data for model fitting may be collected from a combination of direct field measurements (see Appendix B), peer-reviewed scientific literature and/or technical reports issued by government agencies. Field data must be collected to cover the entire range of methane emissions flux potentially expected by the project, as well as the values of covariates that correspond to that range. Additional guidance is provided in Section 4.1.7 of the *VCS Standard v3.3*.

When data are collected directly by the project proponent in the field, a data collection plan (or protocol) must be prepared, detailing the data collection methods and referencing appropriate technical source documents.

Monitoring Requirements: Data Collection for Proxy Methane Model
The first monitoring report must include the following if an proxy model is used to estimate methane flux:
MRR.57 Complete references to the source of any data collected from literature or reports.
MRR.58 Data collection procedures, plans or protocols for any data collected directly from the project area.

9.2.2.2.3 Model Fitting, Selection, and Goodness of Fit

This methodology is not prescriptive with regard to model form and fitting procedures, as various types of models may be appropriate depending on the observed relationship between covariates and response variables. However, the model must be fit using sound and well documented statistical methods. The model must predict methane flux in tCO_2e/day (or units that can be converted appropriately) from some combination of measurable covariates. The project proponents must consider a variety of model forms and data transformations as appropriate to the data collected. During model fitting, attention should be paid to outliers and overly influential data points. Residual plots should be analyzed to confirm that model fitting assumptions have been met. Model selection and goodness of fit must be evaluated as described in Appendix F.

Monitoring Requirements: Model Fit for Methane
The first monitoring report must include the following if a proxy model is used to estimate methane flux:
MRR.59 The form of the selected model.
MRR.60 Summary statistics of the model fit as appropriate to the fitting of the model.
MRR.61 The estimated model parameters.
MRR.62 A description of the range of covariate data with which the model was fit.

9.2.2.2.4 Predicting Methane Flux

When a proxy model is used, measurement of the selected covariates replaces direct measurement of methane flux at each verification event. Covariates must be measured according to the procedures outlined by the project proponent in Section 9.2.2.2.1 and their actual values reported. Use the measured values as inputs to the statistical model. In the case that there is uncertainty about the value of a covariate model input, choose the value that results in the most conservative (ie, largest) estimate of methane emissions flux. Models must not be extrapolated more than 10% (that is, no independent variables that exceed the range from which the model was fit by more than 10% must be input into the model).

Monitoring Requirements: Model Prediction for Methane
The first monitoring report must include the following if an proxy model is used to estimate methane flux: **MRR.63** The values of any measured covariates. **MRR.64** The predicted methane flux.

9.2.2.3 Direct Measurement

Either chamber measurements (Section 9.2.2.3.2), eddy covariance measurements (Section 9.2.2.3.3), or other substantive equivalent techniques must be used. The project proponent must select the measurement method at the time of validation.

Monitoring of gas fluxes is inherently uncertain when aggregated over space and time. This methodology addresses this uncertainty by providing requirements that ensure the fluxes are overestimated, rather than underestimated, using conservativeness as a mediator to accuracy. These requirements include guidelines for stratification, a requirement for making measurements in the stratum expected to have the highest emissions, and guidelines for the points in time during which measurements are made.

To convert monitoring data from flux per acre per day to flux per day as required in Section 8.2.2, use equation [G.10].

Monitoring Requirements: Processed Chamber and Eddy Covariance Flux Data
The monitoring report must include the following: **MRR.65** A table of chamber flux or eddy covariance emission summary statistics of the mean (±1SEM) and number of samples for each mean in tCO_2e/ac/day for each sample location within a stratum.

9.2.2.3.1 Stratification

Stratification must be used to determine the stratum that is likely to yield the greatest methane emissions flux over the course of a year. Appendix A, Section A.1, provides general guidelines for stratifying the project area. Direct measurements must be conducted in the stratum that is likely to yield the greatest methane emissions flux, and may optionally be conducted in other strata as well, using appropriate area weighted stratification estimators as provided in appendix A.

The following factors predominantly affect methane emissions flux:

1. Carbon source: Methane emissions are associated with productive emergent plants that supply labile organic matter for methane producing bacteria. Areas with stressed plants or low plant productivity may have limited emissions over an annual period.

2. Soil saturation or reduction-oxidation potential: Persistent soil saturation or inundation above the wetland surface indicates reduced conditions and a likelihood of enhanced methane emissions. Methane production occurs when the reduction-oxidation potential is less than < 200mV. Optimal methane production occurs when redox is below -200mV.

3. Sulfate (salinity): The absence of sulfate favors methane production. The regular replenishment of sulfate with seawater from tidal action can suppress methane production. Methane production can occur when sulfate is less than 4mM umol (or typically when salinity < 18ppt).

4. Plant traits: 'Shunt' plant species are capable of conducting methane from the soil to atmosphere. A comprehensive list of species is not known, however, candidate genera that contain substantial aerenhymatous roots and shoots includes: *Typha*, *Sagittaria*, *Peltandra*, *Nuphar*, *Nymphaea*, *Phragmites*, and *Cladium* (see Couwenberg 2009).

5. Electron acceptors: In the absence of sulfate and other electron acceptors, such as nitrate and iron, methane production may be enhanced.

These factors must be considered when determining the stratum that is likely to yield the greatest methane emissions flux. The project proponent must justify the selected strata for direct measurement, including time considerations related to cyclical changes in the tidal frame.

Strata boundaries may change over time. If this occurs, the project proponent must ensure that the stratum likely to yield the greatest methane flux is always measured.

PD Requirements: Stratification for Methane Emissions
The project description must include the following if direct measurement is used to estimate methane flux: **PDR.65** Description for how the strata were delineated. **PDR.66** Map(s) of the initial strata boundaries indicating which stratum is likely to yield the greatest methane emissions flux. **PDR.67** Justification per the criteria in Section 9.2.2.3.1 for the stratum that is likely to yield the greatest methane emissions flux.

Monitoring Requirements: Stratification for Methane Emissions
The monitoring report must include the following if direct measurement is used to estimate methane flux:
MRR.66 Map(s) of the current strata boundaries.
MRR.67 A description of changes to the strata boundaries (if applicable).

9.2.2.3.2 Chamber Measurements

If the chamber measurement method is selected, the project proponent must take direct measurements of methane flux using chambers. The project proponent may use the protocols prescribed in Appendix B as the basis for flux measurement in the monitoring plan.

Within stratum, chambers must be located in areas that are likely to yield the greatest methane emissions flux over the course of a year (see factors in Section 9.2.2.3.1).

PD Requirements: Instrumentation for Chambers
The project description must include the following:
PDR.68 Diagram of chamber design.

Monitoring Requirements: Instrumentation for Chambers
The monitoring report must include the following:
MRR.68 Diagram of chamber design.
MRR.69 Map showing the location of chambers in the project area.

9.2.2.3.3 Eddy Covariance Measurements

The project proponent may take direct measurements of methane flux using eddy covariance. The project proponent may use the protocols prescribed in Appendix C as the basis for flux measurement in the monitoring plan.

The footprint of the eddy covariance tower must be more than half in the stratum determined to yield the greatest methane emissions flux over the course of a year (see factors in Section 9.2.2.3.1). The tower must be located in the stratum determined to yield the greatest methane emissions flux over the course of a year. The footprint of the tower must be defined using a published model (eg, Kljun et al. 2004, Kormann and Meixner 2001).

Monitoring Requirements: Instrumentation for Eddy Covariance	
The monitoring report must include the following:	
MRR.70	Diagram or map of eddy covariance tower delineating the selected footprint area where flux was integrated from and the computed mean 80% footprint distance (including the footprint model used) from the tower during the period of analysis. A table of computed estimates for each of the following parameters: σ_w = standard deviation of the vertical velocity fluctuations (m/s) u^*= surface friction velocity (m/sec) z_m= measurement height (m) z_0= roughness length (m) (or canopy height and density to be used to estimate roughness length)
MRR.71	Description of the published model used to define the footprint.
MRR.72	Map showing the location of eddy covariance towers in the project area.
MRR.73	Documentation of adherence to manufacturer-recommended procedures for calibration of the methane analyzer.

The project proponent must use one of the software packages for eddy covariance data processing listed below. An inter-comparison of some of these software packages for eddy covariance data quality control was reviewed by Mauder et al. (2008), and any of these packages must be considered equally acceptable for computing GHG fluxes. Eddy covariance algorithms may be used in other commercial software, such as MatLab, but will require justification from the project proponent.

- EddyPro 4.0 (fully documented, maintained, and supported by LI-COR®, Inc.)
- ECO_2S (IMECC-EU)
- EdiRe (Rob Clement, University of Edinburgh)
- TK3 (Matthias Mauder and Thomas Foken, University of Bayreuth)
- ECPack (GNU Public License; Wageningen University);
- EddySoft (Olaf Kolle and Corinna Rebmann, Max-Planck Institute for Biogeochemistry)
- Alteddy (Jan Elbers, Alterra Institute in Wageningen)

The project proponent must plot a time series of 30 min data including methane concentration, surface friction velocity and temperature. Data points must be omitted based on the following thresholds:

- Methane concentration must not be less than ambient (< 1.7 ppm) or the regional average, which is available from the nearest NOAA ERSL laboratory field station.

- Surface friction velocities less than 0.10 m/s or greater than 1.2 m/s.

Upper and lower limits of daily temperature should be within norms of the nearest meteorological station.

Monitoring Requirements: Eddy Covariance Data Processing and Flux Computation
The monitoring report must include the following: **MRR.74** Frequency diagram of wind direction (0-359° with 30° intervals) and velocity (m/s) for the period of analysis. **MRR.75** Summary of the dates of data collection, the selected approach for averaging over each period, explicit formulas used for computing flux, number of 0.5-hr samples used in calculations. **MRR.76** Graphical plot of 0.5-hr GHG concentration (ppmv), wind velocity and direction, and temperature used for the flux calculations **MRR.77** Summary statistics (number of samples, mean, median, variance) of GHG flux for each averaging period.

9.2.2.4 Frequency of Measurement

The project proponent must monitor methane flux periodically during a sampling period. The frequency of measurement is dependent upon the measurement method selection (ie, chamber or eddy covariance).

9.2.2.4.1 Chamber Measurements

The sampling period must be defined by a chamber sampling type selected from Table 13; guidance on the appropriate seasons for sampling activities is given for the northern hemisphere. The chamber sampling type may change from monitoring period to monitoring period, but must never change within a monitoring period. The project proponent must justify their selection of the chamber sampling type every monitoring period.

Table 13: Measurement requirements for chambers

Chamber Sampling Type	Sampling Period	Frequency	Period Flux Calculation ($tCO_2e/ac/d$)	Annual Flux Calculation ($tCO_2e/ac/yr$)
Peak	June - August	Minimum of two sampling events. If only two, no less than 30 days between events.	Mean of all measurements during the sampling period.	Mean period flux * 365 days.
Seasonal	October – February (winter) March – May (spring) June – September (summer)	Minimum of four sampling events. Each season must have at least one event and the summer season must have at least two, with no less than 30 days between events.	Mean of all measurements per each sampling season.	SUM of the mean winter season flux * 151 days and the mean spring season flux * 92 days and the mean summer season flux * 122 days.
Monthly	January - December	Minimum of 12 sampling events with no less than seven days between events. Minimum of one event per each calendar month.	Mean of all monthly measurements during the sampling period.	Mean period flux * 365 days.

Methane production from wetland soils predominantly occurs when mean soil and water temperatures exceeds 20°C (Whalen 2005). Because the peak chamber sampling type is during the hottest months in the northern hemisphere, this sampling type is most conservative; it also requires the least amount of sampling. Seasonal and Monthly chamber sampling types may provide a more accurate estimate of seasonal and inter-annual fluxes.

Sampling must occur when water levels are within mean low and mean high water (ie, not during extended low water events).

Monitoring Requirements: Chamber Sampling for Methane	
The monitoring report must include the following:	
MRR.78	Table of sampling event dates for the monitoring period, including the time of day samples were collected, water level relative to the soil surface, soil temperature, and air temperature.
MRR.79	Copy of field data sheets documenting time intervals when samples were collected, sample identification number, and verification of the total number of samples received by the laboratory.

9.2.2.4.2 Eddy Covariance Measurements

The sampling period must be defined by the eddy covariance sampling type and the eddy covariance sampling type must be selected from Table 14; sampling periods are given for the northern hemisphere. The eddy covariance sampling type may change from monitoring period to monitoring period, but must never change within a monitoring period. The project proponent must justify their selection of the eddy covariance sampling type every monitoring period.

Flux measurements must not be verified during the sampling period if the selected eddy covariance sampling type is peak or seasonal.

Table 14: Measurement requirements for Eddy Covariance

Eddy Covariance Sampling Type	Sampling Period	Frequency	Period Flux Calculation ($tCO_2e/ac/d$)	Annual Flux Calculation ($tCO_2e/ac/yr$)
Peak	July 1 – September 30	Minimum of 21 days.	Mean of all measurements during the 21 cumulative days (or more).	Mean period flux * 365 days.
Seasonal	March 1 – May 30 (spring) July 15 – September 15 (summer)	Minimum of 21 days sampled in the spring and minimum of 21 days sampled in the summer.	Mean of all measurements during the 21 cumulative days (or more) per each season.	SUM of the mean spring season flux * 243 days and the mean summer season flux * 122 days.
Monthly	January - December	Minimum of 3 days sampled per calendar month. No less than 7 days between sampling events.	Mean of all measurements during the 36 days (or more).	Mean period flux * 365 days.

The following criteria establish the frequency of measurements within each day:

1) A sample interval is 0.5 hr.

2) A minimum of 12 samples must comprise a daily flux mean.

3) One missing sample between two samples may be linearly interpolated. No interpolation is allowed for time periods greater than 1 hr.

4) A list of interpolated samples must be recorded and provided to the verifier.

PD Requirements: Eddy Covariance Measurement
The project description must include the following: **PDR.69** The type of analyzer selected for direct measurements of methane, including a description of the resolution of measurements (in ppb) and the frequency at which measurements are to be taken (in Hz). **PDR.70** A table of meteorological variables selected for measurement. For each variable in the table, justification for its selection, the unit of measurement, resolution of measurement and frequency of measurement. **PDR.71** A description the eddy covariance tower configuration including the distances between sensors (vertical, northward and eastward separation). **PDR.72** A scale diagram of the eddy covariance tower configuration showing the relative location and distance of the anemometer relative to the methane sensor. **PDR.73** Plan view diagram or map of the eddy covariance tower delineating strata and the area of highest anticipated emissions within a 100m radius of the tower. Delineation of any patch vegetation (twice the dominant canopy height and occupying >100m^2 in area) occurring within the estimated 80% footprint area. **PDR.74** Description of dominant plant canopy height (in m) over an annual cycle. An estimate of the 80% flux footprint distance (in m) and parameter estimates, as follows: σ_w= standard deviation of the vertical velocity fluctuations (m/s) u_*= surface friction velocity (m/sec) z_m= measurement height (m) h_m= planetary boundary layer height (m) or 1000m z_m= roughness length (m) or 1/10th of the average canopy height

Monitoring Requirements: Eddy Covariance Measurement
The monitoring report must include the following: **MRR.80** A table of meteorological variables selected for measurement. For each variable in the table, an indication of whether the variable was measured, the make and model of the instrument used for measurement. **MRR.81** For each measured variable, a graphical plot or table of the data with respect to time during the monitoring period. A data table or plot must include at minimum: air temperature, methane concentration, methane flux. A list of interpolated/missing samples. **MRR.82** Documentation of calibration dates and zero checks for methane analyzer. Provide the date of last full calibration (0-10 ppm methane standard). Provide dates of carbon-free air gas checks for methane analyzer.

9.2.3 Monitoring Project Nitrous Oxide Flux

Nitrous oxide may be *de minimis* as determined per Section 8.4.3.2 and current VCS requirements. If it is not *de minimis*, the project proponent must monitor nitrous oxide flux $F_{P\,\Delta\,N2O}^{[m]}$ using one of three approaches: applying default values (Section 9.2.3.1), proxy methods developed by the project proponent (Section 9.2.3.2) or direct measurement of flux from the project area (Section 9.2.3.3). All three approaches result in an estimate of flux in units of tCO_2e/day, which is then used in equation [G.13] to predict emissions as a result of project activities (see Section 8.2.3). Specific field methods for measuring nitrous oxide flux are described in Appendix B.

In deciding which monitoring approach to use, it should be kept in mind that direct measurement is usually the most demanding in terms of time and cost. If the project proponent is able to identify a default value or model that meets the requirements herein, these will likely be the most efficient methods.

Once an approach is selected, it cannot be changed after the first verification event.

PD Requirements: Monitoring Nitrous Oxide
The project description must include the following: **PDR.75** The selected approach for monitoring nitrous oxide.

9.2.3.1 Default Values

This section provides peer-reviewed estimates for nitrous oxide emissions flux in a variety of wetland ecosystems in several regions of North America (primarily Louisiana). The values provided in Table 16 may be used to determine a default value for nitrous oxide emissions.

If the project proponent demonstrates that the project area is not located within a direct 'outfall' of a NPDES major discharger (as described in this section) and is not located within a CWA Section 303d designated impaired water, the project proponent may use an applicable default value provided in Table 16 of Section 9.2.3.1.1, taking into consideration the issues described in this section in order to determine if the values in Table 16 are applicable to the project. If the project area is determined to be within the 'outfall' of a NPDES major discharger (ie, affected by external nitrate loading) or is located within a CWA Section 303d designated impaired water, the project proponent must either apply a proxy model (see Section 9.2.3.2) or conduct direct monitoring (see Section 9.2.3.3).

Prior to selecting a default value from Table 16, the project proponent must determine whether there exists an external nitrogen loading that is likely to influence gas fluxes in the project area. The project proponent must provide supporting evidence to show where major point sources of nitrogen are located relative to the project area and to define the hydrologic connections that lead to direct discharge into the project area. Major point sources of nitrogen may include state-authorized NPDES permits (industrial or municipal wastewater effluent) or public works projects resulting in the alteration of surface water flow into wetlands and estuaries (eg wetland restoration projects with freshwater/sediment river diversions). Major non-point nitrogen sources from surface runoff or wastewater – including agricultural, urban and suburban areas, leach fields, and leaking sewer pipes – also must be considered.

Specifically, the project proponent must demonstrate:

1. The project area is not located within a direct 'outfall,' nor is it downstream and in close proximity of a NPDES major discharger (>1 mgd) or public works project (river diversion) discharging elevated nitrogen effluent (>3 mg TN/L);

2. The project area is not located within a CWA Section 303d designated impaired water, where nitrogen (or 'nutrients') is the suspected causal factor of impairment; and

3. The project area does not receive direct surface runoff from agricultural, urban or suburban areas, and is not immediately adjacent to areas with sewer lines or leach fields.

Acceptable sources of supporting documentation to demonstrate the presence or absence of external nitrogen loading may include: state-authorized National Pollutant Discharge Elimination System (NPDES) documentation; Clean Water Act 303d Impaired Waters documentation; watershed-based Total Maximum Daily Load (TMDL) regulations; project-specific monitoring reports; first order, area-based water quality models; and ambient water quality monitoring data.

PD Requirements: Determining Project Area Exposure to Nitrogen Loading
The project description must include the following: **PDR.76** Location of the project area within a minimum definable watershed, using a USGS, EPA or state delineated watershed. **PDR.77** Locations of all NPDES major dischargers and public works projects producing > 1 MGD of elevated nitrogen effluent (>3 mg TN/L) discharging into the project area and located within the minimum definable watershed. **PDR.78** List of EPA CWA Section 303d designated impaired waters for the state.

Alternatively, other peer-reviewed estimates may be used, in which case the project proponent must demonstrate and justify the selected default value. Where default factors are used, they must be consistent with the current version of the VCS Standard's requirements for default factors (currently located in Section 4.5.6 of the VCS Standard version 3.3). The project proponent must calculate the selected default value in terms of tCO_2e/year and apply this calculated default to determine emissions in equation [G.13]. Models must be publicly available, though not necessarily free of charge, from a reputable and recognized source (eg, the model developer’s website, IPCC or government agency).

PD Requirements: Default Values for Nitrous Oxide Monitoring
The project description must include the following if a default value is used to estimate nitrous oxide flux: **PDR. 79** Justification for the selected default value.

9.2.3.1.1 Default Factors in Absence of External Nitrate Loading

Under background wetland conditions, defined as those wetland areas not exposed to external nitrate loading sources (eg, a river diversion or wastewater treatment outflows, or other significant point sources), in the Mississippi River delta plain, nitrous oxide emissions flux to the atmosphere is ≤0.1 t CO2e/ac/yr (Smith et al. 1983). Under these conditions, the project proponent may use a value from Table 16, making sure to justify its applicability to the project area.

Table 15 shows annual estimates of nitrous oxide emissions fluxes from vegetated wetland and open water habitats across a salinity gradient in Louisiana (Smith et al. 1983),. The study was done over 2 years with samples taken on ~6 week intervals (17 sampling events) using static flux chambers at sites representative of background conditions for Louisiana wetlands (in the absence of external nitrate loading). The emissions fluxes are presented relative to an anticipated annual sequestration rate of 3 tCO_2e/ac/yr.

Table 15: Background annual nitrous oxide flux values from vegetated wetland and open water habitats across a salinity gradient in Louisiana (Smith et al. 1983)

Wetland Type	Annual mg N20-N/m2/yr	Annual $tCO_2e/ac/yr$	% of Benefit @ 3 $tCO_2e/ac/yr$
Salt marsh	31	0.06	2.0%
open water	10	0.02	
Brackish marsh	48	0.09	3.2%
open water	21	0.04	
Fresh marsh	55	0.11	3.6%
open water	34	0.07	

For projects in Louisiana, the values provided in Table 15 may be used to estimate nitrous oxide flux. For projects outside Louisiana, the project proponent must identify appropriate flux estimates from peer-reviewed literature and must demonstrate that they are applicable to the project.

The effects of river diversions on nitrous emissions flux to the atmosphere are less predictable than background conditions. Nitrous oxide emissions flux from freshwater wetlands near the outfall of river diversions may depend on whether the diversion is operating (positive flux to the atmosphere ~0.4 t CO2e/ac/yr; Yu et al. 2006) or not operating (flux from the atmosphere to the wetland -0.17 t CO2e/ac/yr; Table 15, Yu et al. 2006). The study of Lundberg (2012) conducted along a salinity gradient from the outfall of one river diversion showed that wetland nitrous emissions flux to the atmosphere are relatively low (< 0.07 t CO2e/ac/yr).

9.2.3.1.2 Projects in Presence of External Nitrate Loading

Exposure to high external nitrate loads may result in increased nitrous oxide emissions flux compared to background conditions. For project areas in the presence of external nitrate loading, the project proponent must either apply a proxy model (see Section 9.2.3.2) or conduct direct monitoring (see Section 9.2.3.3).

9.2.3.2 Proxy Modeling

Project proponents may develop new proxy models to predict nitrous oxide flux from wetland ecosystems. In building such a predictive model, the project proponent must measure or collect published data on response variables (nitrous oxide flux) using the guidance in Appendix B as well as possible covariates, consider a range of alternative models and select a model using statistically sound procedures, and apply the model at each verification event to predict nitrous oxide flux. Use Sections 9.2.3.2.1, 9.2.3.2.2, 9.2.3.2.3 and 9.2.3.2.4 to develop new proxy models.

Although the possible covariates to nitrous oxide flux must be reported at the time of validation, the selected model and data used to fit the model must be reported at the time of the first verification event.

9.2.3.2.1 Considering Covariates

In developing a statistical model, project proponents must first develop a list of possible covariates and list sources of potential data for those covariates, which may include direct field measurement, remote sensing, peer-reviewed scientific literature, and technical reports completed by government agencies. From the initially considered covariates, identify those whose data availability and expected relationship with methane flux are most relevant to the project needs.

Possible and selected covariates and sources for covariates must be validated.

PD Requirements: Covariates for Proxy Nitrous Oxide Models
The project description must include the following if an proxy model is used to estimate nitrous oxide flux: **PDR.80** A list of possible covariates and the sources of data available for each. **PDR.81** A list of selected covariates to be used for model fitting.

9.2.3.2.2 Collecting Data for Model Fitting and Response Variables

Data for model fitting may be collected from a combination of direct field measurements (see Appendix B), peer reviewed scientific literature and/or technical reports issued by government agencies. Field data must be collected to cover the entire range of nitrous oxide emissions flux potentially expected by the project, as well as the values of covariates that correspond to that range.

When data are collected directly by the project proponent in the field, a data collection plan (or protocol) must be prepared, detailing the data collection methods and referencing appropriate technical source documents.

Monitoring Requirements: Data Collection for Proxy Nitrous Oxide Model
The first monitoring report must include the following if an proxy model is used to estimate nitrous oxide flux: **MRR.83** Complete references to the source of any data collected from literature or reports. **MRR.84** Data collection procedures, plans or protocols for any data collected directly from the project area.

9.2.3.2.3 Model Fitting, Selection, and Goodness of Fit

This methodology is not prescriptive with regard to model form and fitting procedures, as various types of models may be appropriate depending on the observed relationship between covariates and response variables. However, the model must be fit using sound and well-documented statistical methods. The model must predict nitrous oxide flux in tCO_2e/day (or units that can be converted appropriately) from some combination of measureable covariates. The project proponents must consider a variety of model forms and data transformations as appropriate to the data collected. During model fitting, attention should be paid to outliers and overly influential data points. Residual plots should be analyzed to confirm that model fitting assumptions have been met. Model selection and goodness of fit must be evaluated as described in Appendix F.

PD Requirements: Model Fit for Nitrous Oxide
The project description must include the following if an proxy model is used to estimate nitrous oxide flux: **PDR.82** Justification that the proxy is an equivalent or better method (in terms of reliability, consistency or practicality) to determine the value of interest than direct measurement.

Monitoring Requirements: Model Fit for Nitrous Oxide
The first monitoring report must include the following if an proxy model is used to estimate nitrous oxide flux: **MRR.85** The form of the selected model. **MRR.86** Summary statistics of the model fit as appropriate to the fitting of the model. **MRR.87** The estimated model parameters. **MRR.88** A description of the range of covariate data with which the model was fit.

9.2.3.2.4 Predicting Nitrous Oxide Flux

When a proxy model is used, measurement of the selected covariates replaces direct measurement of nitrous oxide flux at each verification event. Covariates must be measured according to the procedures outlined by the project proponent in Section 9.2.2.2.1 and their actual values reported. Use the measured values as inputs to the statistical model. In the case that there is uncertainty about the value of a covariate model input, choose the value that results in the most conservative (ie, largest) estimate of nitrous oxide emissions flux. Models must not be extrapolated more than 10% (that is, no independent variables that exceed the range from which the model was fit by more than 10% must be input into the model).

Monitoring Requirements: Model Prediction for Nitrous Oxide
The first monitoring report must include the following if an proxy model is used to estimate nitrous oxide flux: **MRR.89** The values of any measured covariates. **MRR.90** The predicted nitrous oxide flux.

9.2.3.3 Direct Measurement

If using direct measurements, the project proponent must measure nitrous oxide flux using chambers. The project proponent may use the protocols prescribed in Appendix B as the basis for flux measurement in the monitoring plan.

Monitoring of gas fluxes is inherently uncertain when aggregated over space and time. This methodology addresses this uncertainty by providing requirements that ensure the fluxes are overestimated, rather than underestimated, using conservativeness as a mediator to accuracy. These requirements include guidelines for stratification, a requirement for making measurements in the stratum expected to have the highest emissions, and guidelines for the points in time during which measurements are made.

To convert monitoring data from flux per acre per day to flux per day as required in Section 8.2.3, use equation [G.12].

9.2.3.3.1 Stratification

Stratification must be used to determine the stratum that is likely to yield the greatest nitrous oxide emissions flux over the course of a year. Appendix A, Section A.1, provides general guidelines for stratifying the project area. Direct measurements must occur in the stratum that is likely to yield the greatest nitrous oxide emissions flux, and may optionally be made in other strata as well, using appropriate area-weighted stratification estimators as provided in Appendix A to determine a weighted-average estimate of flux for the project area. Strata boundaries may change over time. If this occurs, the project proponent must ensure that the stratum likely to yield the greatest nitrous oxide flux is always measured.

PD Requirements: Stratification for Nitrous Oxide Emissions
The project description must include the following if direct measurement is used to estimate nitrous oxide flux: **PDR.83** Description for how the strata were delineated. **PDR.84** Map(s) of the initial strata boundaries indicating which stratum is likely to yield the greatest nitrous oxide emissions flux. **PDR.85** Justification per the criteria in Section 9.2.2.3.1 for the stratum that is likely to yield the greatest nitrous oxide emissions flux.

Monitoring Requirements: Stratification for Nitrous Oxide Emissions
The monitoring report must include the following if direct measurement is used to estimate nitrous oxide flux: **MRR.91** Map(s) of the current strata boundaries. **MRR.92** A description of changes to the strata boundaries (if applicable).

9.2.3.3.2 Chamber Measurements

In most cases, chamber measurements for nitrous oxide flux will be collocated with methane flux. In the event that they are not collocated, the requirements of Section 9.2.2.4.1 must be used to identify the location of chambers for nitrous oxide.

9.2.3.4 Frequency of Measurement

There are two options for the frequency of nitrous oxide flux measurements:

1. In conjunction with chamber samples of methane flux per Section 9.2.2.4.1 (if applicable); or

2. Approximately once per calendar month, a minimum of 12 samples that are no less than seven days apart.

For either option, nitrous oxide flux must be calculated as the mean of all measurements.

Monitoring Requirements: Chamber Sampling for Nitrous Oxide
The monitoring report must include the following: **MRR.93** Table of sampling event dates for the monitoring period, including the time of day samples were collected, water level relative to the soil surface, soil temperature, and air temperature. **MRR.94** Copy of field data sheets documenting time intervals when samples were collected, sample identification number, and verification of the total number of samples received by the laboratory.

9.2.4 Monitoring Project Energy Consumption

Units of energy that are consumed as a result of project activities and monitoring activities must be monitored using the direct measurement approach or the cost approach (see Sections 9.2.4.1 and 9.2.4.2).

Monitoring Requirements: Energy Consumption Measurement Method
The monitoring report must include the following: **MRR.95** The selected approach to monitoring energy consumption.

9.2.4.1 Direct Measurement of Energy Consumption

If direct measurement is used, the project proponent must maintain separate records of energy consumption for each energy type listed in Table 10 (see Section 8.1.1). The total units of energy consumed during the monitoring period for each energy type is recorded as $G^{[m]}_{P\,\Delta\,(ty)}$.

Monitoring Requirements: Direct Measurement of Energy Consumption
The monitoring report must include the following: **MRR.96** Energy consumption for each energy type listed in Section 8.1.1. **MRR.97** References to records of energy consumption.

9.2.4.2 Cost Approach to Energy Consumption

The cost approach to estimating energy consumption assumes that the project proponent does not possess definitive, itemized records of energy expenditures, given that energy and fuel costs often are paid directly by dredging subcontractors and actual energy consumption is not often reported. If the cost approach is used, the project proponent must extrapolate energy consumption based on the project budget and historic energy costs. The project proponent must adhere to the following procedure:

1. Determine the proportion of the dredging budget estimated for fuel (or electricity) purchases,
2. Identify the energy type(s) likely to have been used in the course of dredging, and
3. Calculate the estimated energy consumption by energy type using published historic energy prices (eg, U.S. Energy Information Administration) at the time of dredging activities. The estimate of total units of energy consumed during the monitoring period for each energy type is recorded as $G_{P\,\Delta\,(ty)}^{[m]}$.

The project proponent must justify how the energy prices and proportion allocated to energy type is conservative; the most conservative scenario will always be to assume the lowest energy prices and allocate the highest emission factor for each type.

Monitoring Requirements: Cost Approach to Energy Consumption	
The monitoring report must include the following:	
MRR.98	Justification for the proportion of dredging budget allocated for fuel (or electricity) purchases.
MRR.99	Justification for choice of energy type(s).
MRR.100	Documentation of historic energy costs at the time of dredging activities.
MRR.101	Justification of estimate of energy consumption.

9.2.5 Monitoring Project Sediment Transport

Emissions from energy consumption are based upon the mass of sediment transported as a result of project activities. The mass of sediment transported is given by equation [G.2] where $M_{P\,\Delta}^{[m]}$ is the mass of sediment dredged from the sediment source as a result of project activities during the monitoring period, $V_{P\,\Delta}^{[m]}$ is the volume of transported sediment, and $d_{P\,\Delta}^{[m]}$ is the density of the transported sediment. The estimated volume of transported sediment must be based upon the volume of the catchment area to which dredged sediment is transported. Given that dredged sediment is likely to be a solid-liquid mixture, the density must be measured as equation [G.1].

Monitoring Requirements: Monitoring Sediment Transport	
The monitoring report must include the following:	
MRR. 102	Justification for the estimate of volume of dredged sediment transported.
MRR. 103	Justification for the estimate of the density of dredged sediment.
MRR.104	Estimated mass of sediment transported.

9.2.6 Monitoring Allochthonous Carbon

For projects that do not meet the criteria for the conservative exclusion of allochthonous carbon import (per Section 5.2.1), the project proponent must monitor allochthonous carbon sedimentation. Accretion measurements (ie, with a marker horizon technique) must be used to estimate the fraction of allochthonous mineral-associated carbon with sedimentation.

Based on literature values for the project area, a conservative deduction must be assessed according to the procedures described in Appendix E.6.4 and using equation [E.4]. Using regionally appropriate literature, the project proponent must use a peer-accepted correction factor (typically ≤3% of the mineral content is bound by organic matter, see Andrews et al. 2011) for the type of wetland system (eg, fluvial, non-fluvial) in order to compute the mass of the mineral-associated carbon that must be subtracted from total soil carbon accumulation during the monitoring period.

Monitoring Requirements: Monitoring Allochthonous Carbon	
The monitoring report must include the following:	
MRR.105	Reference(s) to the regionally appropriate literature used to determine the correct factor for mineral-associated carbon.

9.2.7 Monitoring Baseline Methane Flux

Baseline monitoring for methane must be conducted in a suitable reference area (as defined in Section 6.3.1). Methane monitoring (chamber or eddy covariance) must conform to the requirements in Sections 9.2.2 and must use the sampling designs and specifications outlined in Appendices B and C.

9.2.8 Procedures for Quality Control and Assurance

The monitoring plan must specify specific measures for quality control and assurance. These measures must conform to the requirements in Sections 9.2.8.1, 9.2.8.2 and 9.2.8.3.

9.2.8.1 Field Measurements

The project proponent must develop a monitoring plan that includes a detailed field sampling protocol. Field data must be spot-checked for errors in sampling, transcription, and analysis (see Section 9). The project description must describe the type and frequency of training for field personnel responsible for sampling carbon stocks, fluxes, and covariates. The monitoring report must document the type and training field personnel received during the monitoring period.

PD Requirements: Field Training for Field Sampling
The project description must include the following: **PDR.86** A description of the type and frequency of training of field personnel responsible for sampling carbon stocks, fluxes, and covariates.

Monitoring Requirements: Field Training for Field Sampling
The monitoring report must include the following: **MRR.106** The type and frequency of training of field personnel during the monitoring period.

9.2.8.2 Data Transcription and Analysis

Project proponents must document a procedure for ensuring high quality data is used in determining emissions reductions and removals. This procedure must include methods for recording and archiving data, checking data for errors, and analyzing data in a transparent manner. To the extent possible, analysis methods should be maintained throughout the lifetime of the project (eg, using the same spreadsheets, software, and computer code for all calculations made during the project lifetime). A percentage of any data entered manually should be randomly checked for transcription errors, preferably by a person not involved in the initial entry.

9.2.8.3 Carbon Stock Measurements

All carbon stock data from individual plots must be provided to the validation/verification body, along with all spreadsheets or computer code used to calculate project-level carbon stocks and associated uncertainties. Data analysis should be carefully checked for transcription or calculation errors. The distribution of biomass estimates by plot should be examined and compared to available literature to confirm that reasonable results have been achieved; a similar procedure must be followed for SOC. Any plots with unusually high or low biomass or SOC (ie, outliers) should be examined closely. It is good practice to re-measure a subset of biomass plots to verify the accuracy of field measurements when non-destructive sampling techniques are used. When destructive sampling is used, evidence of calibration of instruments (such as scales) must be provided.

Monitoring Requirements: Carbon Stock Measurements	
The monitoring report must include the following:	
MRR.107	Biomass and SOC carbon stock data for all plots, along with any ancillary spreadsheets or computer code used to generate these predictions.
MRR.108	List of outliers with unusually high or low biomass or SOC, including justification for their continued inclusion.
MRR.109	Results of accuracy assessment if non-destructive sampling techniques are used. Otherwise, justification for why accuracy need not be formally addressed.

9.2.8.4 Eddy Covariance Data

The project proponent must take direct measurements of methane flux using eddy covariance. The project proponent may use the protocols prescribed in Appendix C as the basis for flux measurement in the monitoring plan.. Refer to Section 9.2.2.4.2 for eddy covariance sampling requirements. Requirements for calibration are found in Section C.2.5.

PD Requirements: Quality Control and Assurance of Eddy Covariance Data	
The project description must include the following:	
PDR.87	Any methodology deviations. Such deviations must include the text that is being modified and the proposed new language.

Monitoring Requirements: Quality Control and Assurance of Eddy Covariance Data	
The monitoring report must include the following:	
MRR.110	Description of processing software used, assumptions, and data quality control measures, which must include the selected method of coordinate rotation, detrending, and density fluctuation correction.

9.2.8.5 Laboratory Analyses

The analysis of methane and/or nitrous oxide from chamber samples (see Sections 9.2.2.3.2 and 9.2.3.3, Appendix B) must meet or exceed USEPA QA/QC requirements. The selected laboratory must provide written pre-analysis sample processing procedures, specific chemistry test methods and detection limits for the analysis.

Sample analyses must follow the EPA Method 3C (Determination of Carbon Dioxide, Methane, Nitrogen, and Oxygen from Stationary Sources). Instrument calibration must comply with EPA Protocol Gaseous Calibration Standards.

Soil samples must be analyzed for bulk density and SOC by a qualified laboratory following the methods of Nelson and Sommers 1996 and Ball 1964, respectively, or comparable methods. The chosen laboratory must have a rigorous Quality Assurance program that meets or exceeds the USEPA QA/QC requirements or similar international standards for laboratory procedures, analysis reproducibility, and chain of custody. The laboratory must also provide a document that defines the pre-analysis sample processing procedures, and the specific chemistry test methods they use at the laboratory, including the minimum detection limits for each constituent analyzed.

Monitoring Requirements: Laboratory Analyses	
The monitoring report must include the following if samples are sent to a laboratory:	
MRR.111	Documentation of the laboratory QA/QC protocols, the methods of sample analysis, and general calibration procedures used the laboratories conducting the analysis.

9.3 Data and Parameters Available at Validation

Data Unit / Parameter	A_{PA}
Data unit	acre
Description	Size of project area
Equations	[G.10], [G.12]
Source of data	GIS analysis prior to sampling
Justification of choice of data or description of measurement methods and procedures applied	-
Purpose of data	
Comments	

Data Unit / Parameter	$e_{(ty)}$
Data unit	tCO_2e/gal, tCO_2e/scf, tCO_2e/kWh
Description	Emissions coefficient for energy type *ty*
Equations	[G.3], [G.14]
Source of data	Emission factors in Section 8.1.1, Table 10
Justification of choice of data or description of measurement methods and procedures applied	Selected from published values
Purpose of data	
Comments	

Data Unit / Parameter	$g_{B\ (ty)}$
Data unit	gal/tonne, scf/tonne, kWh/tonne
Description	Energy consumed per metric tonne of sediment dredged in the baseline
Equations	[G.3]
Source of data	Documentation provided by project proponent
Justification of choice of data or description of measurement methods and procedures applied	Direct measurement

Purpose of data	
Comments	

Data Unit / Parameter	$p_{B\ (ty)}$
Data unit	proportion (unitless)
Description	Proportion of energy for energy type *ty* consumed in the baseline scenario
Equations	[G.3]
Source of data	Documentation provided by project proponent
Justification of choice of data or description of measurement methods and procedures applied	Calculated from direct measurement
Purpose of data	
Comments	

PD Requirements: Data and Parameters Available at Validation
The project description must include the following: **PDR.88** The value of each variable, data and parameter. **PDR.89** The units, descriptions, source, purpose and comments for each variable reported in the PD.

9.4 Data and Parameters Monitored

Data Unit / Parameter	$C_{P\ CS\ (c)}^{[m]}$
Data unit	tCO_2e
Description	Cumulative project carbon stock in pool *c* at end of monitoring period
Equations	[G.7]
Source of data	Sampling of carbon stocks
Description of measurement methods and procedures to be applied	See Appendix D
Frequency of	At least every five years

monitoring/recording	
QA/QC procedures to be applied	Independent review of equations and check against literature estimates. See Section 9.2.8.3
Purpose of data	
Calculation method	
Comments	

Data Unit / Parameter	$d_{LQD}^{[m]}$
Data unit	kg/m3
Description	Density of liquid in dredged sediment
Equations	[G.1]
Source of data	Direct measurement
Description of measurement methods and procedures to be applied	See Section 9.2.5
Frequency of monitoring/recording	Where sediment is transported, Every monitoring period.
QA/QC procedures to be applied	Compare data from multiple samples. See Section 9.2.8.1
Purpose of data	
Comments	

Data Unit / Parameter	$d_{SLD}^{[m]}$
Data unit	kg/m^3
Description	Density of solids in dredged sediment
Equations	[G.1]
Source of data	Direct measurement
Description of measurement methods and procedures to be applied	See Section 9.2.5
Frequency of monitoring/recording	Where sediment is transported, Every monitoring period
QA/QC procedures to be applied	Compare data from multiple samples. See Section 9.2.8.1
Purpose of data	

Comments	

Data Unit / Parameter	$f_{B\,\Delta\,CH4}^{[m]}$
Data unit	$tCO_2e/ac/day$
Description	Baseline methane emissions flux per unit area
Equations	[G.5]
Source of data	Static chamber or eddy covariance measurement
Description of measurement methods and procedures to be applied	See Section 9.2.7
Frequency of monitoring/recording	Every monitoring period
QA/QC procedures to be applied	Comparison of data from multiple samples and independent review of calculations. See Sections 9.2.8.1, 9.2.8.4, and 9.2.8.5
Purpose of data	
Comments	

Data Unit / Parameter	$f_{P\,\Delta\,CH4}^{[m]}$
Data unit	$tCO_2e/ac/day$
Description	Methane emissions flux per unit area within project area
Equations	[G.10]
Source of data	Static chamber or eddy covariance measurement
Description of measurement methods and procedures to be applied	See Section 9.2.2.3
Frequency of monitoring/recording	Every monitoring period
QA/QC procedures to be applied	Comparison of data from multiple samples and review of monitoring records. See Sections 9.2.8.1, 9.2.8.4, and 9.2.8.5
Purpose of data	
Comments	

Data Unit / Parameter	$f_{P\,\Delta\,N2O}^{[m]}$

Data unit	tCO_2e/ac/day
Description	Nitrous oxide emissions flux per unit area within project area
Equations	[G.12]
Source of data	Static chamber or eddy covariance measurement
Description of measurement methods and procedures to be applied	See Section 9.2.3.3
Frequency of monitoring/recording	Every monitoring period
QA/QC procedures to be applied	Comparison of data from multiple samples and review of monitoring records. See Sections 9.2.8.1, 9.2.8.4, and 9.2.8.5
Purpose of data	
Comments	

Data Unit / Parameter	$G_{P\,\Delta\,(ty)}^{[m]}$
Data unit	gal, scf, kW
Description	Energy consumed in project area for energy type *ty* over monitoring period
Equations	[G.14]
Source of data	Direct measurement approach or cost approach
Description of measurement methods and procedures to be applied	See Sections 9.2.4.1 and 9.2.4.2
Frequency of monitoring/recording	Every monitoring period when sediment is transported
QA/QC procedures to be applied	Independent review of calculations and monitoring records. See Sections 9.2.8.1 and 9.2.8.2
Purpose of data	
Comments	

Data Unit / Parameter	${p_{SLD}}^{[m]}$
Data unit	proportion (unitless)
Description	Proportion of solids by weight in the dredged sediment
Equations	[G.1]
Source of data	Direct measurement of dredged sediment

Description of measurement methods and procedures to be applied	See Section 9.2.5
Frequency of monitoring/recording	Every monitoring period when sediment is transported
QA/QC procedures to be applied	Comparison of data from multiple samples and review of monitoring records. See Sections 9.2.8.1 and 9.2.8.2
Purpose of data	
Comments	

Data Unit / Parameter	$t^{[m]}$
Data unit	days
Description	Elapsed time from project start at the end of the monitoring period
Equations	[G.11], [G.13]
Source of data	Monitoring records
Description of measurement methods and procedures to be applied	N/A
Frequency of monitoring/recording	Every monitoring period
QA/QC procedures to be applied	N/A
Purpose of data	
Comments	

Data Unit / Parameter	$t^{[m-1]}$
Data unit	days
Description	Elapsed time from project start at the beginning of the monitoring period
Equations	[G.11], [G.13]
Source of data	Monitoring records
Description of measurement methods and procedures to be applied	N/A
Frequency of	Every monitoring period

monitoring/recording	
QA/QC procedures to be applied	N/A
Purpose of data	
Comments	

Data Unit / Parameter	$V_{P\,\Delta}^{[m]}$
Data unit	m^3
Description	Volume of sediment dredged from the sediment source over monitoring period
Equations	[G.2]
Source of data	Direct measurement
Description of measurement methods and procedures to be applied	See Section 9.2.5
Frequency of monitoring/recording	Every monitoring period when sediment is transported
QA/QC procedures to be applied	Independent review of calculations and monitoring records. See Section 9.2.8.2
Purpose of data	
Comments	

Monitoring Requirements: Data and Parameters Monitored	
The monitoring report must include the following:	
MRR.112	The value of each variable, data and parameter.
MRR.113	The units, descriptions, source, purpose, references to calculations and comments for each variable reported in the Monitoring Report.
MRR.114	For those variables obtained from direct measurement, a description of measurement methods and procedures. These may simply be references to components of the monitoring plan.
MRR.115	For those variables obtained from direct measurement, a description of monitoring equipment including type, accuracy class and serial number (if applicable). These may simply be references to components of the monitoring plan.
MRR.116	Procedures for quality assurance and control, including calibration of equipment (if applicable).

9.5 Grouped Projects

Grouped projects are allowable in order to permit the expansion of project activities after initial validation. For such projects, project documentation may differ by project activity instance with respect to carbon stock estimation, as stratification and plot location will vary. Otherwise, the same monitoring requirements set out in Section 9 apply.

As per Section 9.2.1.1, during the first verification including new project activity instances, all new plots must be measured.

If the original project area is stratified for SOC or biomass, then subsequent project activity instances must be similarly stratified as well, per Section 9.2.1.2.

Monitoring Requirements: Monitoring Grouped Projects	
The monitoring report must include the following when new project activity instances are added to the project:	
MRR.117	List and descriptions of all project activity instances in the project.
MRR.118	Project activity instance start dates.
MRR.119	Map indicating locations of project activity instances added to the group.
MRR.120	List of additional stratifications used for additional project activity instances; justification for why flux measurements are still located in the most conservative stratum (9.2.2, 9.2.3).
MRR.121	As project activity instances are added, the monitoring plan must be updated to reflect additional monitoring times and plot locations.

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APPENDIX A: DEFAULT STRATIFICATION AND SAMPLE UNIT ALLOCATION METHODS

Stratification, in which a population to be sampled is divided into sub-populations of known size, can be used in measurements of many variables to improve sampling effectiveness, and can help reduce uncertainty when it would be cost-prohibitive to conduct statistical sampling of sufficient density to adequately represent the entire population. The default stratification methods, including guidelines for the stratification criteria of individual variables, are described in Sections 9.1, 9.2.1.2, 9.2.2.3.1, and 9.3.2.3.1. Here, formulas that can be used to estimate means and totals from stratified samples are provided, as well as guidelines for efficiently allocating sampling units to identified strata.

Stratification should always be done prior to measurement, such that the stratum sizes are known exactly. Stratification may be performed prior to any measurement event. Different stratification schemes may be used for estimating different variables according to the preferences of the project proponent.

A.1 Sample Size and Plot Allocation

In stratified random sampling, the following equations may be used to estimate the sample size required to attain a targeted precision level. Note that this methodology does not require that sample size be calculated in this way—these equations are provided solely for the convenience of the user. Estimating sample size as described here requires an estimate of the mean and standard deviation of the variable to be estimated. These quantities may be estimated from literature or from a pilot sample. The project proponent should recognize that actual standard error of a sampled statistic will be subject to random error, and that if the mean and standard deviation used to estimate the sample size differ significantly from those properties in the actual population, the sample size actually required for the targeted precision level will also from that estimated. The most efficient allocation of plots to strata depends on the relative sizes of the strata, the estimated means and within strata variability, and potentially the costs of sampling each stratum. Three methods are available for allocating sample units, which are described below. Actual sampling units within strata should be chosen systematically with a random starting point or randomly.

A.1.1 Proportional Allocation

Proportional allocation allocates sampling units to strata in proportion to their size. Given a targeted precision level, the total required sample size may be calculated as:

$$\hat{n}_{TOTAL} = \frac{1}{\left(\frac{\mathrm{E}\times\bar{x}}{Z\times\hat{\sigma}_{\bar{x}}}\right)^2 + \frac{\mathrm{n}}{\mathrm{N}}}$$		[A.1]
Variables	E - The allowable degree of error (eg, 0.15 for +/- 15%) $\bar{x}$ - The estimated mean of the quantity to be estimated Z - Z statistic from a normal distribution associated with the desired confidence level (1.96 for 95% confidence). $\hat{\sigma}_{\bar{x}}$ - The estimated standard deviation of the quantity to be estimated $\frac{\mathrm{n}}{\mathrm{N}}$ - The relative size of a sampling unit with respect to the entire population to be sampled (for example, in sampling with fixed area plots, this is the ratio of the plot size to the total project area size)	
Section References	9.2.1, Appendix D, Appendix E	
Comments	The estimated required sample size	

The plots are allocated to strata in proportion to strata size as follows:

$$\hat{n}_{(k)} = \hat{n}_{TOTAL}\frac{a_{(k)}}{A_{PA}}$$		[A.2]
Variables	$\hat{n}_{TOTAL}$ - The estimated total required number of plots $a_{(k)}$ - The area of stratum *k* A_{PA} - The total project area	
Section References	9.2.1, Appendix D, Appendix E	
Comments	The number of plots to be allocated to stratum *k*	

A.1.2 Neyman Allocation

Sometimes strata differ in their degree of within-stratum variability. In this case, the overall standard error will be minimized if sampling efforts are concentrated toward those strata with highest variability. If estimates of the standard deviation of each stratum are available, the following equations may be used to allocate sampling units:

$$w_{(k)} = \frac{a_{(k)}\hat{\sigma}_{(k)}}{\sum_{(j)\in\mathcal{S}} a_{(j)}\,\hat{\sigma}_{(j)}} \quad \text{[A.3]}$$

Variables	$a_{(k)}$ - The area of stratum *k* $\hat{\sigma}_{(k)}$ - The estimated standard deviation of the quantity to be estimated within stratum $\mathcal{S}$ - The set of all strata $a_{(i)}$ – The area $\hat{\sigma}_{(j)}$ – The standard deviation
Section References	9.2.1, Appendix D, Appendix E
Comments	The proportion of total sample size to be allocated to stratum k

$$\hat{n}_{TOTAL} = \frac{\sum_{(k)\in\mathcal{S}} \frac{a^2_{(k)}\hat{\sigma}^2_{(k)}}{w_{(k)}}}{\left(\frac{\mathrm{E}\times\bar{x}}{\mathrm{Z}} \times \frac{\mathrm{n}}{\mathrm{N}}\right)^2 + \sum_{(k)\in\mathcal{S}} a_{(k)}\,\hat{\sigma}_{(k)}{}^2}$$ [A.4]	
Variables	$a^2{}_{(k)}$ - $a_{(k)}$ - The area of stratum *k* $\hat{\sigma}^2{}_{(k)}$ - The estimated standard deviation of the quantity to be estimated within stratum $\mathcal{S}$ - The set of all strata E - The allowable degree of error (eg, 0.15 for +/- 15%) $\bar{x}$ - The estimated mean of the quantity to be estimated $w_{(k)}$ – proportion of total sample size to be allocated to stratum k Z - Z statistic from a normal distribution associated with the desired confidence level (1.96 for 95% confidence). $\frac{\mathrm{n}}{\mathrm{N}}$ - The relative size of a sampling unit with respect to the entire population to be sampled (for example, in sampling with fixed area plots, this is the ratio of the plot size to the total project area size)
Section References	9.2.1, Appendix D, Appendix E
Comments	The estimated total required number of plots

$$\hat{n}_{(k)} = \hat{n}_{TOTAL} w_{(k)}$$	[A.5]
Variables	$w_{(k)}$ – proportion of total sample size to be allocated to stratum k $\hat{n}_{TOTAL}$ - The estimated total required number of plots
Section References	9.2.1, Appendix D, Appendix E
Comments	The number of plots to be allocated to stratum *k*

A.1.3 Optimal Allocation

A third allocation method incorporates both information about within strata variability and the potential for varying costs for sampling different strata:

$$w_{(k)} = \frac{a_{(k)}\hat{\sigma}_{(k)}/\sqrt{c_{(k)}}}{\sum_{(j)\in\mathcal{S}} a_{(j)}\,\hat{\sigma}_{(j)}/\sqrt{c_{(j)}}}$$	[A.6]
Variables	$a_{(k)}$ - The area of stratum *k* $a_{(j)}$ – The area of stratum *j* $\hat{\sigma}_{(k)}$ - The estimated standard deviation of the quantity to be estimated within stratum $\mathcal{S}$ - The set of all strata E - The allowable degree of error (eg, 0.15 for +/- 15%) $c_{(k)}$ or $c_{(j)}$ - The cost of sampling stratum *k* or *j*
Section References	9.2.1, Appendix D, Appendix E
Comments	The proportion of total sample size to be allocated to stratum k

A.2 Totals and Standard Errors from Stratified Samples

The total of a quantity of interest may be estimated from a stratified sample

$$\hat{T} = \sum_{(k)\in\mathcal{S}} \frac{a_{(k)}}{n_{(k)}} \sum_{(j)\in\mathcal{P}_{(k)}} y_{(j,k)}$$ [A.7]	
Variables	$a_{(k)}$ - The area of stratum *k* $\mathcal{S}$ - The set of all strata $n_{(k)}$ – Number of sampling units in stratum k $\mathcal{P}_{(k)}$ – Set of all sampling units in stratum k $y_{(j,k)}$ - A quantity estimated for or measured on sampling unit j in stratum k
Section References	9.2.1, Appendix D, Appendix E
Comments	The estimated total quantity in the sampled area

$$\sqrt{\sum_{(k)\in\mathcal{S}} \left[\frac{a_{(k)}^2 \hat{\sigma}_{(k)}^2}{\#\left(\mathcal{P}_{(k)}\right)}\left(\frac{N_{POSSIBLE\ (k)} - \#\left(\mathcal{P}_{(k)}\right)}{N_{POSSIBLE\ (k)}}\right)\right]}$$ [A.8]	
Variables	$a_{(k)}$ - The area of stratum *k* $\hat{\sigma}_{(k)}^2$ - The estimated within-stratum variance of stratum *k* $\mathcal{S}$ - The set of all strata $\mathcal{P}_{(k)}$ – Set of all sampling units in stratum k $N_{POSSIBLE\ (k)}$ = total number of possible plots in stratum k
Section References	D.1, D.2
Comments	The estimated standard error of the total

APPENDIX B: DEFAULT STATIC CHAMBER MEASUREMENT METHODS

The project proponent may deviate from the methods provided in this appendix per the requirements of Section 9.

GHG emissions fluxes have been measured with the static (closed) or dynamic (with air circulation) chamber techniques on a wide variety of wetland sites (Moore and Roulet 1991). There are a number of chamber techniques that are used to isolate soil respiration or develop carbon budgets and sophisticated soil flux systems are commercially available. While there are acceptable variations in equipment and techniques, this guidance focuses on describing a static chamber method, with discrete time series of gas measurements during each monitoring period, to calculate methane flux for baseline and project monitoring. Nitrous oxide or carbon dioxide fluxes may be sampled in the same manner, depending on project requirements. With attention to minimizing chamber and soil disturbance, periodic sampling with static chambers can provide an estimate of project area GHG emissions on a daily time scale, which is then extrapolated to annual estimates.

The methods described here are specific to herbaceous marshes where vegetation heights are typically less than 1.0 m, and present optimal conditions to sample all contributions of GHG exchange, particularly soil diffusion, ebullition, and plant-mediated transport of methane. Closed chamber methods that only isolate soil processes, by excluding vegetation, may underestimate the contribution of methane release from plants (through xylem transport to the atmosphere), which can be considerable from certain wetland 'shunt' species that have well developed aerenchyma. Therefore, vegetation must not be excluded from wetland-based sampling, but an exception exists when open water sampling may be necessary for quantifying fluxes from this habitat type. Clipping of emergent plants above the water level to accommodate the dimensions of the flux chamber is allowable immediately prior to sampling. The technique of using dynamic chambers with semi-continuous measurements of GHGs may also be used but will require a justification of the technique and description by the project proponent.

B.1 Chamber Description

Chamber size or design must be scaled to accommodate the existing vegetation height and seal the soil surface so that plant-mediated, diffusion, and ebullition fluxes are captured. Chamber design guidelines described here follow that of Yu et al. (2008) and Parkin and Venterea (2010). A cylinder or box chamber must not have a cross-sectional area less than 200 cm^2. The base seals the soil column and is permanently installed and left in the field during the monitoring period. If the base is disturbed by natural or human causes, it must be reinstalled and allowed to equilibrate for a minimum of two weeks prior to additional sample collection.

The chamber top must be less than 1.0 m in vertical height, and is only installed or fit to the permanently installed base during sampling periods. It contains two or more sealed (syringe septa) gas collection ports that allow sampling when water levels are high or low. One port will have a tube that extends lower in the chamber for retrieving samples when water level is low, and the other port(s) must have a shorter tube(s) to collect samples higher in the chamber when water level is high. Where the chamber base and top seal together there must be a gas-impermeable gasket or water trough.

Cylinder or box chamber materials may consist of stainless steel, aluminum, PVC, polypropylene, polyethylene, or plexiglass. Opaque or clear chambers are acceptable. Black material must not be used given its potential for excessive heating of the chamber in sunlight. The chamber base must have drainage ports along its vertical length to eliminate chamber flooding between monitoring periods.

For sampling open water habitats, chamber specifications are the same as above; however, a permanent chamber base or collar is not required. Rather the chamber top may be outfitted with floatation that can form a seal with the water surface.

B.2 Plot Establishment for Chambers

B.2.1 Replication

Within a stratum, there must be a minimum of two plots comprising three replicate chambers per plot. Each plot must occur within a 100 m radius of a randomly chosen sampling location center point.

From the center point, chambers may be randomly located within a 100 m radius of habitat that is representative of the stratum. Factors that must be considered for plot location include dominant vegetation type and marsh surface elevation. In choosing sample locations, project proponents must justify that the locations chosen are conservative – that is, within a stratum, chambers should be located in areas in which methane flux is expected to be greatest (see section 9.2.2.3.1 for a description methane flux indications). Typically, this involves positioning chambers in areas that occupy lower elevations in the landscape that still support dense vegetation coverage. The arrangement of chambers within this radius will be dependent on the marsh topography and a suitable amount of existing habitat to re-locate chamber plots if needed in the future. There are no minimum or maximum distance requirements between replicate chambers but the chambers should be placed such that sampling can occur within the prescribed time intervals.

B.3 Chamber Installation

Most wetland conditions will require the construction of boardwalks to minimize soil disturbance during chamber deployment and subsequent sampling. Site specific conditions (water table depth, soil permeability) will dictate the depth to which the base of the chamber is fitted into the soil; the base should be installed to a depth no lower than the mean water table depth of the site. Installation of chambers may take place anytime of the year and should occur when water levels are at or below the soil surface.

The chamber base is installed to the soil by slicing and excavating a trench that will accommodate its dimensions. The base must capture representative vegetation cover and species and disturbance to vegetation in the chamber area must be minimized. To allow soil/plant disturbance effects to diminish, the chamber must equilibrate for a minimum of two weeks prior to any sampling. Drainage ports will remain open during the equilibration period and between verification events.

PD Requirements: Chamber Description
The project description must include the following: **PDR.90** A description of the chamber design, with its dimensions or total volume, and cross-sectional area. **PDR.91** Diagram of chamber plot randomization design and the resulting chamber locations within each stratum, with the chambers identified as replicates. Provide dates when chambers were deployed in each stratum. Provide a justification that the locations chosen are conservative (ie, that they are likely to predict methane emissions flux for the entire stratum for which they are representative.)

B.4 Chamber Sampling

Flux chamber measurements require collecting syringe gas samples of ambient air outside of the chamber, replicate samples within the chamber base prior to sealing with the chamber top, and then successive samples over an incubation period less than 2 hours after sealing the chamber. A minimum of three sample intervals should be collected: time = 0 hours (unsealed chamber), time = 0.5 hours (30 min after chamber sealed), t = 1.0 hours (60 min after chamber sealed). Exact sample times are recorded during sampling.

Steps:

1. Inspect the chamber base for any physical disturbance.
2. Drainage ports that are open to atmosphere are plugged before inserting the chamber top.
3. Sample vials are vacuumed with a 10 ml syringe.
4. Collect one ambient atmosphere gas sample outside of the chamber and inject into the sample vacuum vial.
5. Duplicate (n=2) gas samples are collected inside the chamber base prior to sealing with the top of the chamber.
6. The chamber top is sealed to the base. Stopwatch is started at t=0.
7. With the chamber sealed, duplicate samples are collected at 30 min intervals and injected into vacuum vials. One minute prior to each sample collection, a stirring procedure is done by

inserting a 30 ml syringe into the chamber septa and withdrawing and expelling the full volume twice.

8. After sampling is complete, the chamber top is removed and the drainage ports are unplugged.

Samples must be stored out of direct sunlight during transport to the laboratory. A chain of custody form should be completed by the field lead and submitted to the laboratory with the samples to be maintained with their records. The steps for open water sampling follow those for wetland-based sampling.

B.5 Data Processing and Analysis

Gas concentration data from lab analyses are in volumetric units (L trace gas : L total gas) and are corrected for chamber volume, cross-sectional area and linear change with time to yield flux volume (L trace gas m^{-2} hr^{-1}), according to the following equation:

$$f_v = v_{CHAM} * c_v * 1/a_{CHAM} \quad [B.1]$$

Variables	f_v - flux of trace gas (volume basis) in the chamber headspace over the enclosure period, corrected for chamber volume and cross sectional area (L trace gas m^{-2} hr^{-1}) v_{CHAM} - chamber volume (L) c_v - change in gas concentration over the enclosure period, or slope of best fit line calculated from simple linear regression (L trace gas L^{-1} total gas hr^{-1}) a_{CHAM} - cross-sectional area of soil enclosed by the chamber base (m^2).
Section References	9.2.2.3
Comments	Guidance for assessing goodness of fit is provided in section F.3 of Appendix F. Curve fitting methods for non-linear rates of trace gas change are outlined in: Parkin, T.B. and R.T. Venterea. 2010. Sampling protocols. Chapter 3. Chamber–based Trace Gas Flux Measurements. In: Sampling Protocols R. F. Follett, ed. P.3-1 to 3-39. www.ars.usda.gov/research/GRACEnet

To convert from volumetric to mass flux basis, the ideal gas law is used in the following equation:

$$f_{P\,\Delta} = \frac{f_v * P}{R * T} * M * 24 * 0.000001 * GHGcf$$ [B.2]	
Variables	$f_{P\,\Delta}$ - mass of trace gas flux (tCO_2e ac/day) f_v - flux of trace gas (volume basis) (L trace gas m^{-2} hr^{-1}) *P* - barometric pressure (atm) *T* - air temperature (°K) *R* - universal gas constant (0.0820575 L atm/°K mol) *M* - molecular weight of trace gas (g/mol)
Section References	9.2.2.3
Comments	24 = conversion from hr to day 0.000001 = conversion from g to tonnes $GHGcf$ = GHG correction factor to CO2e, use 21 (CH_4) and 310 (N_2O)

With the series of repeated measures of gas concentration from a chamber, simple linear regression is used to compute the slope of gas concentration with time (c_t), which represents one replicate of gas flux (see equation [B.1]). A minimum of three replicate chambers (or plots) must be used to compute a mean flux (±1SEM) for a given location within a stratum for each verification event or sample date. Refer to Section 9.2.2.3 for chamber flux calculations.

APPENDIX C: DEFAULT EDDY COVARIANCE MEASUREMENT METHODS FOR METHANE

The project proponent may deviate from the methods provided in this appendix per the requirements of Section 9.

Eddy covariance or eddy correlation is a widely accepted micrometeorological technique to estimate flux of heat, water, atmospheric trace gases and pollutants and relies on turbulence to calculate fluxes. The semi-continuous nature of sampling allows for diurnal, seasonal, and annual budgets of energy and GHGs between the biosphere and atmosphere. Measuring carbon fluxes with the eddy covariance method has the advantage of covering broader space and more continuous measurements, unlike chamber flux techniques. The two methods may be used in concert in a heterogeneous landscape to evaluate flux contribution of distinct landforms (hummocks, hollows, ditches, open water; Teh et al. 2011, Baldocchi et al. 2011) to create a more accurate landscape or project area GHG budget.

Standard operating procedures for designing flux studies and data analyses are being unified by global and regional bio-meteorological communities, such as FLUXNET and AMERIFLUX, respectively. The information presented here draws from their basic guidelines for eddy covariance methods. Open source software is increasingly available for computing GHG fluxes that have been validated by a 'Gold Standard' (see AMERIFLUX, http://public.ornl.gov/ameriflux/sop.shtml) and a selection of the available software is given in Section 9.2.8.4.

Eddy flux is equivalent to the mean dry air density, multiplied by the mean covariance of instantaneous deviations of vertical wind velocity and the mixing ratio of a constituent (methane and carbon dioxide) in air. These covariances are corrected for density fluctuations due to water vapor (Baldocchi et al. 2011).

The eddy covariance technique, while applied in many different ecosystems, is most easily applied in areas where the canopy is relatively homogeneous and the terrain is horizontal. Thus herbaceous wetlands lend themselves well to this technique. Caution is needed when deploying eddy covariance stations, so that vertical disruptions (canopy height changes, trees, buildings) to the boundary layer of interest are minimized. The seven main assumptions for eddy covariance technique are outlined here (from Burba and Anderson 2007) and specific requirements to satisfy these assumptions are described throughout this appendix.

1. Measurements at a point represent an upwind area
2. Measurements are collected in the layer of interest (eg, constant flux layer)
3. The fetch is assumed to be adequate and measures the area of interest
4. Flux is fully turbulent
5. Terrain is horizontal
6. Average of vertical fluctuations is zero, density fluctuations are negligible, and flow convergence and divergence does not occur.

7. Instruments are capable of detecting small changes and measuring at a high frequency (>10 Hz).

There are sources of error that can affect flux computations; however, these errors, such as time lags in measurements and unleveled instruments, are adjusted according to accepted methods during data processing (see Section 9.2.8.4).

C.1 Eddy Covariance Instrumentation

Direct measurements of methane at high frequencies (10-20 Hz) are needed for eddy covariance calculations. For methane, laser absorption spectroscopy is common, and suitable instrumentation is equivalent to those of the closed path Los Gatos tunable diode laser spectrometer (DLT-100 Fast Methane Analyzer), the open path LICOR 7700 (Wave Modulated Spectroscopy), and the Campbell Scientific Trace Gas Analyzers. The chosen methane analyzer must have a resolution of ≤5 ppb methane at 10 Hz (@ 2000 ppb methane) and measurement frequencies must not be less than 10 Hz.

In addition to methane, other meteorological variables must be measured at a frequency (≥10 Hz) equivalent to the gas measurements, including wind and turbulence (three-dimensional sonic anemometer), water vapor, and air temperature. The chosen water vapor analyzer must have a resolution ≤ 0.005 mmol H20/mol air (@ 10 mmol H20/mol air). The sonic anemometer must have a resolution ≤ 0.01 m/sec (@ standard velocity of 12 m/sec). Water vapor measurements will be used to correct for air density fluctuations.

C.2 Tower Configuration

C.2.1 Orientation of Sensors and Equipment

A single tower must be used with the elevated array of eddy covariance instruments contained within a 3 m radius from the center of the tower. If a platform is used, the maximum footprint of the platform and support equipment (solar panels, flow modules, batteries) must not exceed a 5 m radius from the center of the tower base.

High frequency measurements of air properties for eddy covariance require short distances between sensors to minimize time response errors. Instrumentation on the tower must be integrated (ie, trace gas analyzers, anemometer, and temperature sensors) such that distance and orientation between sensors sample the representative air mass properties and allow frequency response corrections.

While configurations may vary depending on the wind direction of interest, the maximum horizontal distance of methane sensor or water vapor intake must not exceed 1.0 m from the center of the anemometer, unless the project proponent provides justification. The distance of the intake sensor for air density and methane sensor must be measured and recorded for elevation, in addition to the northward and eastward separation relative to the center of the sonic anemometer.

C.2.2 Landscape Location of Tower

For conservative project emissions estimates, a primary requirement is to locate the tower within the strata where the highest emissions are anticipated, and at least one-half of the footprint area (as defined by the 80% mean footprint distance) must include the highest emitting strata (see Section 9.2.2.3.1, which defines criteria for determining areas likely to have highest emissions).

The slope of the site must not exceed 1% (1 m vertical /100 m horizontal distance) in any direction within a 200m radius of the eddy covariance tower. The tower may be positioned in the landscape to capture specified wind direction(s) or it may be centrally placed within a homogeneous habitat with adequate fetch to measure all wind directions. In either case, the terrain must be homogeneous with respect to the *mean 80% footprint distance*. Homogeneous terrain here is defined as an area that contains no more than 25% areal coverage of patch vegetation that exceeds twice the dominant plant canopy height. A patch is defined as ≥100 m^2 of species (twice the dominant plant canopy height) covering >70% of the 100 m^2.

C.2.3 Sensor Height

As a general rule a sensor height of 1.0 m above the canopy can integrate fluxes from 100 m upwind under turbulent conditions. Sensor height above the canopy must be no less than one and one-half greater than the dominant plant canopy height in the footprint area. It is permissible to increase or decrease sensor height on the tower to accommodate changes in plant canopy height, as long as the sensor height is maintained above twice the canopy height. Alternately, during data post-processing vegetation canopy height may be adjusted without changing sensor height. Physical changes in sensor height must be recorded and incorporated as offsets during data processing.

C.2.4 Fetch and Flux Footprint

Fetch is described as the horizontal extent from the tower where flux is sampled, whereas the flux footprint describes how much of the measured flux comes from an area at a given horizontal distance. Sufficient fetch is needed to develop an internal boundary layer where fluxes are constant with height (Baldocchi et al. 2001). For every 1.0 m increase in vertical plant structure above an effective surface, approximately 100 m of fetch is needed to readjust the internal boundary layer (Businger 1986, in Baldocchi et al. 1988). To provide adequate fetch, the effective surface (dominant canopy height of interest) must be provided by the project proponent and the sensor height must be twice the dominant canopy height within a minimum radius of 100 m from the tower. If patch vegetation is present it must not exceed the 25% area threshold identified in Section C.2.2.

C.2.4.1 Footprint Distance Estimation

The *mean 80% footprint distance* provides the verifier with information to confirm that flux measurements are being collected within an area that is homogeneous. Here, *mean 80% footprint distance* can be estimated with a predictive model and using daytime turbulence parameters that are typical of the region (ie, from a nearby meteorological station) and the characteristics of the site.

The predicted *mean 80% footprint distance* must be estimated by the project proponent based on the methodology by Klujn et al. (2004), which uses turbulence parameters to predict the location or distance that influences a percentage of the flux. In this case, the project proponent must provide parameter estimates and the results of the predicted footprint distance with 80% flux contribution (online footprint parameterization, http://footprint.kljun.net/varinput.php) to the verifier, based on data known for the project site or estimates from local meteorological stations for the time period of measurement. The parameter estimates must include:

σ_W = standard deviation of daytime vertical velocity fluctuations (m/s)
u_* = surface friction velocity (m/sec)
z_m = measurement height (m)
h_m = planetary boundary layer height (m) or 1000 m
z_m = roughness length (m) or 1/10th of the average canopy height

C.2.5 Calibration

Calibration of methane sensors must be performed by the factory or user according to manufacturer guidelines. When LICOR equipment is used, the intervals for checks and calibration are provided here, while detailed calibration/zero instructions can be accessed via the LICOR website. The methane analyzer (LI-7700) must be fully calibrated spanning a 0 and 10 ppm methane concentration standard at least once annually with standard gases (1% accuracy). Zero and 10 ppm checks of the methane analyzer with hydrocarbon-free and 10 ppm standard gases (accuracy for zero gases = <0.1 ppm Total Hydrocarbon Concentration; accuracy for 10 ppm methane = <0.5 ppm methane) must be conducted at a minimum of twice every six months over one year of data collection. The LI-7200, which measures water vapor and carbon dioxide, must be returned to the factory at least once every three years to confirm the stability of coefficient values on the factory drift table.

C.3 Scale to Project Area

Project field monitoring designs may fall into one of several general approaches that may embrace one uniform habitat type or multiple habitat types in a single location, periodic habitat sampling, or multiple eddy covariance towers contemporaneously measuring different habitats.

1. Stationary single habitat: The simplest case is restricting long-term measurements to a single location that maximizes flux estimates from a homogeneous habitat across seasonal atmospheric and environmental events. The assumption of this approach is that the range of project-scale variability in GHG emissions is adequately characterized over an annual period.

2. Stationary multiple habitats: The eddy covariance tower may be placed a single location that generates information from different habitats that have different source/sink effects. In this case,

data are isolated by the wind direction or quadrant that corresponds to the habitat (open water, scrub-shrub, herbaceous).

3. Complete or periodic coverage of multiple habitats: For project areas with diverse habitats, each habitat type is individually instrumented and measuring simultaneously for valid inter-habitat comparisons. Another approach is to make periodic movements to different habitats with an eddy covariance tower. The degree to which periodic deployments in different locations approximate average conditions must be demonstrated by the project proponent.

Regardless of the method chosen above to scale from the tower location to the project area, project proponents must justify that the tower locations selected result in conservative estimates of methane emissions flux. To do this, project proponents must:

1. Stratify the project area based on measureable factors expected to impact methane emissions flux. These factors may include but are not limited to elevation, vegetation cover, and salinity.

2. Calculate the percentage of the total project area that falls into each methane emissions flux stratum.

3. Using the mean 80% footprint distance defined above, calculate the percentage of the expected tower footprint that falls within each stratum.

4. Demonstrate that, if the proportion of the tower footprint area that falls within each stratum differs from the proportion of the total project area that falls within each stratum, the tower footprint area contains a proportionally greater area of strata expected to have high methane emissions flux. For example, if two strata are identified (low and high emissions flux), and the project area is 40% low and 60% high, a tower footprint that includes 70% high emissions flux strata and 30% low is acceptable, while a footprint that includes 55% high emissions flux strata and 45% low is not. If evidence can be presented that a tower footprint is completely homogenous and all strata are sampled separately, this requirement can be considered satisfied.

$$f_{P\,\Delta\,CH4} = (\overline{\rho a}\,\overline{w's'}) \times 5.61 \times 10^{-3} \times 21$$		[C.1]
Variables	$f_{P\,\Delta\,CH4}$ = CH_4 daily flux (tCO_2e/ac/day) $\overline{\rho a}$ - mean air density for a 0.5 hour sample interval (μmol air/m^3) $\overline{w's'}$ - mean covariance of instantaneous vertical wind velocity and mixing ratio of CH_4 in air w' - instantaneous vertical wind velocity (m/sec) s' - instantaneous mixing ratio of CH_4 in air (μmol gas/μmol air)	
Section References	9.2.2.3	
Comments	5.61×10^{-3} = unit conversion of μmol $CH_4/m^2/s$ to tCH_4/ac/day 21 = conversion of tCH4 to tCO_2e	

C.4 Data Processing and Analyses

Decades of eddy covariance methodology research has resulted in some widely accepted sequences of processing steps and corrections that should be applied. As an evolving science, however, there are debatable topics under discussion. The traditional steps in eddy covariance data processing are outlined below and the project proponent is responsible for specifying how data processing conforms to accepted methods (adapted from Burba and Anderson 2007).

Table 16: Steps to eddy covariance data processing

	Step	Accepted methods	References
1.	**Raw data unit conversion**	- raw voltage to unit conversion	
2.	**Despike**	-signals greater than 6 times the standard deviation for a given averaging period (30 min) must be removed for vertical wind velocity and gas concentration	
3.	**Calibration coefficients**	-may be done during data post processing; or, -user input corrections embedded in the instrument software and metadata	
4.	**Coordinate rotation**	- rotation to mean vertical velocity is equal to zero over a 30 min sample interval; or, -planar fit method; or, -sonic tilt correction algorithms	
5.	**Detrending**	-30 min block averaging must be used -linear and non-linear de-trending should be justified by project proponent	
6.	**Frequency response corrections**	-corrections may include: sensor separation, scalar path averaging, high-low pass filtering.	Moore, C.J. 1986. Frequency response corrections for eddy correlation systems. Boundary Layer Meteorology, 37:17-35.
7.	**Density fluctuation**	WPL correction applied to uncorrected covariances or final fluxes.	Webb, E.K., Pearman, G., and Leuning, R. 1980. Correction of flux measurements for density effects due to heat and water vapor transfer. Quarterly Journal of the Royal Meteorological Society, 106:85-100.

C.5 Flux Footprint Calculations

Flux footprint calculations must employ one of the following methods: Klujn et al. 2004 or Kormann and Meixner 2001. With either method, the project proponent must provide a summary table describing the measured meteorological conditions and the mean 80% footprint distance for the monitoring period. See equation [C.1].

APPENDIX D: DEFAULT BIOMASS MEASUREMENT METHODS

The project proponent must develop a detailed sampling protocol for the purposes of field crew consistency and documentation. The project proponent may deviate from the methods provided in this appendix per the requirements of Section 9.

D.1 Above Ground Tree Biomass

Above ground tree (AGT) biomass includes only trees above a specified diameter and is estimated using allometric equations. For each tree within a given measurement plot, diameter at breast height (dbh) is measured and input into an equation to yield an estimate of above ground biomass. Some equations may also require tree height and/or wood density. Tree biomass is then summed for each plot, and plot biomass estimates are extrapolated across the entire project area to estimate total carbon stocks in AGT biomass.

Project proponents must choose plot size and design. For example, a nested plot configuration may be utilized in order to decrease sampling size necessary to obtain an acceptable level of error. The sampling protocol should reflect the selected sampling scheme.

In each plot, required measurements are taken on every tree falling within the plot based on the sampling protocol. The sampling protocol should explain how to determine whether a given tree is “in” or “out.” The project proponent may decide whether to collect height or wood density based on which metrics are required by selected allometric equations.

When a list of tree species present in the project area is available, allometric equations are to be compiled. Equations may be obtained from peer-reviewed scientific journals or developed by the project proponent, and may be species-specific, genus-specific, or generic form equations. Equations must be validated. When form equations are used, the project proponent must justify that they are conservative for species considered in the project. Since small errors in equations can lead to significant error in the biomass estimate across the entire project, it is important that equations are representative of the trees for which they are utilized—species, locale, and diameter range used to develop the equations should be considered when making selections. If equations require wood density, the project proponent may choose to employ species- or genus-specific values from peer-reviewed scientific journals instead of using field-collected data.

After field measurements are complete, the following steps are taken to calculate total project area carbon stocks in AGT:

- Using Equation [D.1], apply the appropriate allometric equation and convert the resulting biomass to carbon stocks for each tree.
- Using Equation [D.2], AGT carbon stocks are summed for each plot then divided by plot area to yield plot-wide carbon stock density.
- Using Equation [D.4], carbon stocks in each stratum are extrapolated from plot-wide carbon stock density and summed across all strata to yield average AGT carbon stocks for the project.

- Using Equations [A.8], calculate standard error of the average project carbon stock estimate.

D.2 Above Ground Non-Tree Biomass

Grasses, sedges, other herbaceous plants, shrubs, and trees smaller than the AGT pool minimum diameter are included in above ground non-tree (AGNT) biomass. Woody plants (small trees and shrubs) may be measured using either destructively-sampled clip plots or allometric equations, while herbaceous plants, if included, must be measured using clip plots. If a distinction in sampling is made between woody and herbaceous plants, a procedure to ensure that each plant is counted only once must be outlined in the sampling protocol.

Plot size will be chosen by the project proponent and will likely be much smaller than AGT plots. Though plots for AGNT sampling are separate measuring units from AGT plots, they may exist within AGT plots.

D.2.1 Destructive Sampling – Clip Plots

In the destructive sampling method, all plants in the sampling frame within a plot are cut and weighed to measure plot-wide AGNT biomass. Plants should be cut at a consistent height as close to the ground as possible. To aid in determining the extent of the plot, a sampling frame of the desired plot size must be laid on the ground and all plants within must be cut. If possible, biomass must be refrigerated as soon as possible after clipping in order to avoid mass loss due to respiration.

If the project proponent desires, woody and herbaceous plants may be destructively sampled separately, with a smaller plot size for herbaceous plants to improve sampling efficiency.

After harvest, all biomass should be placed in a drying oven at 70° C and weighed periodically until weight is static, indicating that drying is complete. Weigh all dry biomass to determine plot-wide dry weight.

Alternatively, the project proponent may elect to measure wet weight of all biomass in the field and collect a representative and well mixed subsample of which to measure dry weight. The ratio of dry-to-wet weight determined by the subsample would then be multiplied by the plot-wide wet weight to determine plot-wide dry weight.

After measurements are complete, the following steps must be taken to calculate total project area carbon stocks in AGNT:

- Using Equation [D.3], AGNT biomass is converted to carbon stocks and then divided by plot area to yield plot-wide carbon density.
- Using Equation [D.4], carbon stocks in each stratum are extrapolated from plot-wide carbon stock density and summed across all strata to yield average AGNT carbon stocks for the project.
- Using Equations [A.8], calculate standard error of the average project carbon stock estimate.

D.2.2 Allometric Equations

Allometric equations may be used to estimate biomass of trees smaller than the AGT minimum and small shrubs. It is not only less important but also potentially impractical for equations to be specific to the species level in this scenario. The project proponent may wish to destructively sample a subset of shrubs in order to develop one or more allometric equations since doing so for shrubs is far easier than for trees.

The same procedure used to estimate biomass through allometric equations used for AGT biomass must be used to find AGNT; refer to the AGT section. Note that shrub equations may use a different metric such as diameter near root collar (drc) as the independent variable.

D.3 Below ground Biomass

Below ground biomass must be estimated using proportional relationships between above ground and below ground biomass (ie, root-shoot ratios) or by SOC measurement, but not both.

D.3.1 Coarse roots

Coarse roots are defined as roots ≥ 2 mm in diameter, the IPCC suggested minimum diameter for below ground biomass. In partially or wholly forested wetlands, below ground biomass may be estimated with either root-shoot ratios or SOC measurement. In herbaceous wetland creation projects, carbon stock in coarse roots (> 2 mm) is captured by SOC measurement (see Appendix E); root-shoot ratios may not be used to calculate coarse root carbon stock in herbaceous wetlands.

D.3.1.1 Estimation using root-shoot ratios

Carbon stocks in below ground biomass may be estimated by applying a root-shoot ratio to the estimate of above ground tree and/or non-tree biomass yielded in Equation [D.4]. Root-shoot ratios from peer-reviewed literature (eg, Vadeboncoeur, Hamburg, & Yanai, 2007) in a comparable ecosystem and latitude must be used when available. If not available, the root-shoot ratios from the IPCC 2006 Guidelines may be used if appropriate for the ecosystem. The carbon concentration of roots may be determined by taking samples from roots leaving the tree base, using 50% carbon content, or by using the carbon content of above ground biomass.

If this approach is utilized, roots ≥ 2 mm must be removed from soil samples prior to analysis (see Appendix E).

D.3.1.2 SOC Measurement

In the case of herbaceous wetlands—and in forested wetlands, if the project proponent prefers—carbon stocks in coarse root biomass may be included in the SOC pool. If this approach is utilized, root-shoot ratios must not be used.

D.3.2 Fine roots

The carbon stock in fine roots (< 2 mm) is included in the SOC pool (see Appendix E).

D.4 Biomass Measurement Equations

$$x_{(i,j,k)} = \frac{44}{12} \times \frac{1}{1{,}000} \times f_{SPC}(\bullet) \times p_{(SPC)CF}$$	[D.1]
Variables	$f_{SPC}(\bullet)$ - allometric equation for species SPC, with output in kg $p_{(SPC)CF}$ - carbon fraction for species SPC
Section References	D.1
Comments	Carbon stocks in the i^{th} tree in plot j in stratum k (tCO_2e). $\frac{44}{12}$ is the ratio of the mass of carbon dioxide to the mass of carbon and is used to convert to CO2e units. $\frac{1}{1{,}000}$ represents a conversion from kg to tonnes.

$$y_{(j,k)} = \frac{1}{a_{(j,k)}} \sum_{i \in \mathcal{X}_{(j,k)}} x_{(i,j,k)}$$	[D.2]
Variables	$a_{(j,k)}$ - area of plot j in stratum k (ac) $x_{(i,j,k)}$ - estimated carbon stocks in the i^{th} tree in plot j in stratum k (tCO_2e) $\mathcal{X}_{(j,k)}$ - set of all measurements of a type in plot j in stratum k
Section References	D.1
Comments	Carbon stock density in above ground tree biomass in plot j in stratum k (tCO_2e/ac).

$$y_{(j,k)} = \frac{44}{12} \times \frac{1}{1{,}000} \times \frac{p_{(SPC)CF} \times md_{(j,k)}}{a_{(j,k)}}$$ [D.3]	
Variables	$p_{(SPC)CF}$ - carbon fraction for species SPC $md_{(j,k)\_}$ - dry mass of non-tree sample harvested from clip plots in plot j, stratum k (kg) $a_{(j,k)}$ - area of plot j in stratum k (ac)
Section References	D.2.1
Comments	Carbon stock density in above ground non-tree biomass in plot j in stratum k (tCO_2e/ha).

$$C_{P\,CS\,(c)} = \sum_{k \in \mathcal{S}} \frac{A_{(k)}}{n_{(k)}} \sum_{j \in \mathcal{P}_{(k)}} y_{(j,k)}$$ [D.4]	
Variables	$A_{(k)}$ - the area of stratum k (ac) $n_{(k)}$ - number of plots in stratum k $y_{(j,k)}$ - Carbon stock density in plot j in stratum k (tCO_2e/ac) $\mathcal{S}$ - set of all strata for monitoring period m $\mathcal{P}_{(k)}$ - set of all plots in stratum k
Section References	D.1, D.2
Comments	Carbon stocks in pool *c* in the sampled area (tCO_2e).

$$c_{BG\ (p,i)} = c_{AG\ (p,i)} \times r/s$$		[D.5]
Variables	$c_{(p,i)AGx}$ - carbon in above ground biomass in pool p in stratum i for a given monitoring period r/s – root-shoot ratio selected	
Section References	D.3	
Comments	Carbon stock in below ground biomass for a given pool in stratum i.	

APPENDIX E: DEFAULT SOC MEASUREMENT METHODS

Wetland soil carbon can comprise elemental (charcoal, soot), inorganic (carbonates) and organic states (dead and living plant-animal tissue). The organic form is dominant in alluvial soils which are typically poor in carbonate or calcite content. Elemental analyzers can provide direct measurements of total soil carbon, whereas the loss on ignition technique of organic matter combustion can provide an estimate of organic carbon. Chemical oxidation of organic carbon may also be used (Nelson and Sommers 1996).

Soil organic carbon (OC) in mature gulf coast wetlands is relatively constant with depth and averages 26 mg/ml (Gosselink and Hatton 1984). This vertical consistency develops as soils are saturated for extended periods and compaction/oxidation is minimal. Once wetland creation projects attain full plant coverage and long-duration hydroperiods, the process of organic matter vertical accumulation can proceed rapidly (1.0 cm/yr) both above the soil surface (via litter deposition and adventitious root growth) and within the emplaced soil (via root growth). Wetland creation projects will typically begin with a mineral-based soil that is homogeneous in elevation, soil texture, and relatively low in carbon content. The created wetland surface, or original project soil surface, becomes a long-lived marker where carbon accumulation rates can be estimated by measuring changes: (1) within the original project soil, and (2) in vertical accretion above the original project soil surface.

Accretion above the surface and within the original project soil compartments may have carbon infilling (via root growth) and vertical accretion rates. With time, the wetland soil in general may reach an equilibrium point with regards to carbon density. When this happens, changes in soil carbon stocks largely take the form of increasing vertical accretion and not necessarily increasing soil carbon density. A combined approach of soil coring and artificial marker horizons (such as feldspar clay; Knaus and Cahoon 1990) or reference devices (such as sediment reference pins; Steiger et al. 2003; USACE 1993) may be used to account for changes in carbon stocks within both compartments.

E.1 Sampling Design

Project proponents must choose plot size and design. For example, a nested plot configuration may be utilized in order to decrease sampling size necessary to obtain an acceptable level of error. The sampling protocol should reflect the selected sampling scheme.

Guidance for the design, allocation, and demarcation of core locations within a soil measurement plot is provided in VCS Module VMD0021: Estimation of Stocks in the Soil Carbon Pool.

E.2 Description of Soil Compartments

Two soil compartments may be monitored for changes in carbon stocks with time: (1) the original project soil, and (2) newly accreted material above the original project soil surface.

The project proponent may monitor both compartments, or choose to monitor stock changes only within a fixed soil sample depth, for the project lifetime. The project proponent must identify prior to the project start date either of these two methods:

1) fixed soil sample depth; or,

2) fixed soil sample depth *plus* accretion depth.

If for any reason during a monitoring event accretion measurements become unreliable, the fixed soil sample depth becomes the basis for detecting stock changes for the monitoring period.

E.2.1 Original Project Soil

Prior to the project start date, the project proponent must specify a fixed soil sample depth for the original project soil, and this depth will be fixed for the life of the project. The fixed soil sample depth must not exceed 100 cm. The fixed soil sample depth must be sampled in a manner to inventory carbon and bulk properties on a mass- volume basis. There is no requirement on the number of additional depth intervals from the original project soil that must be sampled and analyzed separately.

E.2.2 Accretion above the Original Project Soil Surface

Artificial marker horizons (described in Section E.4) must be used to assess the vertical depth ($d_{accretion}$) of material that has accreted above the original project soil from $t^{[m-1]}$ to $t^{[m]}$. Marker horizons must be deployed at a minimum of once every five years.

E.3 Coring Devices

When soils are sampled for carbon and bulk property analyses, coring devices must be used that are adequate to retrieve volumetrically intact samples. Accretion depth measurements may be taken on soil samples that are excavated with a knife or slicing instrument, but the accretion layer must be collected with a volumetrically controlled corer for carbon and bulk property analysis.

Soil density largely determines the smallest diameter corer than can be used without creating significant compaction. Highly compressible organic soils (bulk density ≤0.20 g/ cm^3) should be collected with a core tube diameter ≥7.6 cm. Soils with a bulk density >0.20 g/cm^3 can be sampled with a core tube diameter < 7.6 cm. Corer materials may consist of but are not limited to aluminum, stainless steel, PVC, or acrylic.

Core devices must allow inspection/measurement of vertical compaction of sample versus field condition. Piston corers should have a sampling base that limits the sample collection to the specified depth. McCauley peat augers may be used to collect organic soils and are designed to minimize compaction.

E.4 Artificial Marker Horizon Establishment

Marker horizons may be established with a feldspar marker technique (Knaus and Cahoon 1990; Folse et al. 2012), which consists of a 1-cm layer of white feldspar clay that is evenly sprinkled on the wetland sediment surface to create a white layer which is easily distinguishable from the natural substrate and can be used to measure surface accretion of sediments over time. Plot size must be approximately 0.25 m^2 or greater. A minimum of three marker horizon plots must be deployed in each stratum.

E.5 Soil Sample Collection

Soil from the accretion layer and the original project soil may be collected as one unit unless discrete horizons are identifiable within the sampling depth found in the original project soil, in which case the soil must be sampled in sub-increments of the sampling depth. However, the accretion layer formed from $t^{[m-1]}$ to $t^{[m]}$ must be separated from the original project soil. The accretion layer and the original project soil must be analyzed for bulk density and carbon content separately, except when an accretion layer is < 1.0 cm, in which case the accretion layer may be incorporated and analyzed for bulk density and carbon content with the original project soil. To properly adjust coring depth, a mean accretion estimate from a stratum must be known prior to sampling soil from the fixed soil sample depth. Thus, there are two soil sampling depth options available for monitoring.

- Soil Sampling Depth Option 1: fixed soil sample depth
- Soil Sampling Depth Option 2: fixed soil sample depth plus accretion depth.

Specific methods for efficient sampling will depend on local soil conditions, so prescriptive requirements for sample size, volume, and sampling depth are not provided in this methodology. Rather, project proponents must develop a locally appropriate sampling plan. In developing this plan, care must be taken that the sampling procedures employed across the depth profile do not bias the estimation of soil organic carbon. In the case that discrete soil horizons can be identified within the selected fixed soil sample depth, each horizon must be sampled separately. The volume of each soil sample taken should be large enough to capture inherent soil structure variability across the depth range represented by the sample.

In the case that a single sample is used to represent a depth range, the sample must be well homogenized prior to analysis, and care must be taken that the sample used for organic carbon determination and bulk density determination are representative of the same depth range. If multiple samples are taken across a vertical soil profile (such as by division of a core into segments), a weighted average should be used to estimate the mean carbon content across the entire depth profile, where the weights are proportional to the percentage of the total sample depth range represented by each subsample.

Refer to the most recent version of VCS Module VMD0021: Estimation of Stocks in the Soil Carbon Pool, the IPCC Good Practice Guidance for Land Use, Land Use Change, and Forestry, and Nelson and Sommers (1996) for more detailed guidance on establishing appropriate sampling protocols.

E.5.1 Accretion above the Original Project Soil Surface

The accretion depth will be measured from a minimum of three feldspar plots per sampling location within a stratum. The mean of the individual measurements from each plot will represent ($d_{accretion}$). The accretion depth from the marker horizons may be sampled by conventional coring, knife excavation, or cryogenic coring techniques. Regardless of technique, at least three measurements of the material thickness above the marker horizon must be taken with calipers or a ruler to the nearest 1.0 mm and recorded on a data sheet. The mean accretion depth will inform the total depth of subsequent soil sampling. The accretion depth must be known prior to determining the overall depth required for soil coring.

E.5.2 Original Project Soil

The original project soil must be sampled with a coring tube of an appropriate diameter (as described in Section E.3). The thickness of ($d_{accretion}$) sediment accretion above the original project soil must be accounted for, when applicable. Otherwise the original project soil is sampled to the fixed soil sample depth defined for the project.

Soil Coring Process:

1. Locate pre-determined sample plot. Remove emergent vegetation by clipping to the soil surface. Insert core tube and drive approximately 5-10 cm deeper than the fixed soil sample depth or the sum of the fixed depth and accretion depth.

2. Measure the vertical height of the soil surface relative to top of the core tube, both inside and outside of core tube to calculate compaction. If height difference is ≥ 10% of the sample depth, remove the core tube and re-sample. If height difference ≤ 10%, remove the core, aided by a cap on the top of the core tube to create a vacuum, or by inserting a hand at the base of the core tube. The core compaction estimate must be documented.

3. Transfer core to an extruding base, which may consist of a 'Meriwether extruder' (Folse et al. 2012) or equivalent device that permits extrusion from the base of the core, such that the upper soil is sectioned first, and deeper layers thereafter.

4. If the accretion depth ($d_{accretion}$) is ≤1 cm, it must be considered to be conservative to include this layer within the original project soil (ie, only core to the original fixed soil sample depth). If the accretion layer is > 1 cm, record the layer thickness as $d_{accretion}$.

5. Extrude the core to the mean accretion depth ($d_{accretion}$) as defined by the marker horizon technique (described in Section E.4 and E.5.1). The soil from this sample depth is removed and placed in a plastic bag labeled with sample location information and the sample depth to the nearest 1.0 cm.

6. After the surface accretion layer has been removed, continue the extrusion process to the original fixed soil sample depth, sectioning at the pre-defined intervals of the original project soil (as described in section E.2.1). Place the sample in a plastic bag with sample location information and deposit depth to the nearest 1.0 cm.

E.6 Soil Sample Analyses

All soil samples must be stored on ice following collection and during transport. A chain of custody form should be completed by the field lead and submitted to the laboratory with the samples to be maintained with their records.

Soil samples must be analyzed for bulk density and SOC by a qualified laboratory following the methods of Nelson and Sommers 1996 and Ball 1964, respectively, or comparable methods.

The chosen laboratory must have a rigorous Quality Assurance program that meets or exceeds the USEPA QA/QC requirements or similar international standards for laboratory procedures, analysis reproducibility, and chain of custody. The laboratory must also provide a document that defines the pre-analysis sample processing procedures, and the specific chemistry test methods they use at the laboratory, including the minimum detection limits for each constituent analyzed.

If root-shoot ratios are used to estimate carbon stocks in coarse roots (≥ 2 mm), such roots must be removed from soil samples prior to analysis. In this case, note that although coarse roots do not count toward mass or carbon content in SOC calculations, their volume should still contribute to soil core volume.

E.6.1 Bulk Density

For bulk density determination, core samples of known volume are collected in the field and oven dried to a constant weight at 105°C (for a minimum of 48 hours). The total sample is then weighed.

The bulk density of the soil core is estimated as:

$$\rho_{SOIL} = M_{soil} \ / \ V_{soil}$$ [E.1]	
Variables	M_{soil} - oven-dried mass of sample soil core (g) V_{soil} - volume of soil core (cm^3)
Section References	
Comments	Bulk density of soil core *j* in stratum *k* (g/cm^3)

Further guidance is provided in Nelson and Sommers (1996).

E.6.2 Direct Carbon Determination

For direct soil carbon determination, individual core samples collected in the field are oven dried to a constant weight at 105°C (for a minimum of 48 hours). Dried samples must be homogenized or ground with a Wiley Mill or ball grinder.

The prepared sample is analyzed for percent organic carbon or g C/g soil (cf_{soil}) using either dry combustion using a controlled-temperature furnace (eg, LECO CHN-2000, LECO RC-412 multi-carbon analyzer, or equivalent), dichromate oxidation with heating, or Walkley-Black method. Further guidance is provided in the IPCC LULUCF Good Practice Guidance (2003) and in Nelson and Sommers (1996).

E.6.3 Indirect Carbon Determination

Indirect carbon estimation techniques may be substituted for direct determination. Organic carbon (OC) can be estimated reliably with the loss-on-ignition (LOI) method, which combusts organic matter from a soil sample, leading to a direct relationship between soil organic matter content and organic carbon content. LOI lab techniques should adhere to those of described in Ball 1964 or Henri et al. 2001. While some variability may exist among samples, OC content should not exceed 50% of the OM content. Table 17 presents the relationships that are acceptable for converting from organic matter to organic carbon.

Table 17: Default equations for estimating organic carbon content from organic matter content with soil samples analyzed with the loss-on-ignition technique

Region	Relationship (OC and OM on a percent dry basis)	Reference
Atlantic	$OC = 0.40 * OM + 0.0025 * OM^2$	Craft et al. 1991
Gulf of Mexico	$OC = 0.4541 * OM$	Steyer et al. 2012
Pacific	$OC = 0.38 * OM + 0.0012 * OM^2$	Callaway et al. 2012

$$c_{SOC\ j} = \left[\sum_{l}^{1-x}\left(cf_{soil,l} * \rho_{soil,l} * \ d_{soil,l}\right) + \sum_{l}^{1-x}\left(cf_{soil,l} * \rho_{soil,l} * \ d_{accretion,l}\right)\right] * \frac{44}{12} * 40.47 - \ c_{alloch,j}$$ [E.2]	
Variables	$c_{SOC\ j}$ = total soil carbon measured at plot *j* ($tCO_2e\ ac^{-1}$) *x* =number of soil layers *l* = soil layer cf_{soil} = organic carbon content of the soil sample in plot *j* in stratum *k* (g C/g soil) ρ_{soil} = soil bulk density of sample in plot *j* in stratum *k* (g/cm3) d_{soil} = depth of a soil sample collected below the surface of the original project soil surface in plot *j* in stratum *k* (cm) $d_{accretion}$ = depth of soil sample collected above a marker horizon (feldspar) or control rod or pin in plot *j* in stratum *k* (cm) $c_{alloch,j}$ = allochthonous soil carbon measured at plot *j* (tCO2e/ac). This quantity is zero if the project meets the criteria in section 5.2.1.
Section References	
Comments	$\frac{44}{12}$ is the ratio of the mass of carbon dioxide to the mass of carbon and is used to convert to CO2e units. 40.47= conversion to t/ac

$$C = \sum_{k \in \mathcal{S}} \frac{A_{(k)}}{n_{(k)}} \sum_{j \in \mathcal{P}_{(k)}} y_{(j,k)}$$	[E.3]
Variables	$A_{(k)}$ - the area of stratum k $n_{(k)}$ - number of plots in stratum k $y_{(j,k)}$ - a quantity estimated for or measured on plot j in stratum k $\mathcal{S}$ - set of all strata for monitoring period m $\mathcal{P}_{(k)}$ - set of all plots in stratum k
Section References	D.1
Comments	Estimated total SOC stock in the sampled area

E.6.4 Allochthonous Carbon Determination

Allochthonous carbon is estimated using a marker horizon technique in order to determine the amount of mineral matter that has been deposited over the monitoring period. The mineral-associated carbon is the component that is classified as allochthonous carbon.

1. Measure the total amount of soil accumulation (accretion depth) during the monitoring period.
2. From the accretion depth, collect soil sediment samples and analyze the samples for bulk density.
3. Calculate the mineral fraction of the soil sample.
4. Use a correction factor to estimate the amount of mineral-associated carbon (allochthonous carbon) to be deducted from the carbon stocks associated with recently deposited sediment.

Core samples of known volume are collected in the field, homogenized in the laboratory, and the homogenized material is sub-sampled for combustion (with the loss-on-ignition technique, described in Section E.6.3), which removes the organic matter/carbon. (The dry bulk density of total sample is measured first; then the organic and mineral content are separated by combustion.) The total remaining material is mineral, and mineral density of the sample is calculated from the original soil sample volume.

The mass of allochthonous carbon of the soil sample above the marker horizon is estimated as:

$$c_{alloch,j} = \sum_{l}^{1-x}(mcf_{soil,l} * \rho_{minsoil,l} * d_{accretion,l}) * \frac{44}{12} * 40.47$$ [E.4]	
Variables	$c_{alloch,j}$- allochthonous soil carbon measured at plot *j* (tCO2e/ac) *x* =number of soil layers *l* = soil layer mcf_{soil} – mineral-associated carbon fraction of the soil sample in plot j in stratum k (%) $\rho_{minsoil}$ – mineral density of sample in plot j in stratum k (g cm^{-3}) $d_{accretion}$- depth of soil sample collected above a marker horizon (feldspar) or control rod or pin in plot j in stratum k (cm)
Section References	9.2.6
Comments	$\frac{44}{12}$ is the ratio of the mass of carbon dioxide to the mass of carbon and is used to convert to CO2e units. 40.47= conversion to t/ac Mineral associated carbon fraction of estuarine soils is typically less than 3% and a locally relevant data source may be used, or see, Andrews JE, Jickells TD, Adams CA, Parkes DJ, and Kelly SD (2011) Sediment Record and Storage of Organic Carbon and the Nutrient Elements (N, P, and Si) in Estuaries and Near-Coastal Seas. In: Wolanski E and McLusky DS (eds.) Treatise on Estuarine and Coastal Science, Vol 4, pp. 9–38. Waltham: Academic Press)

APPENDIX F: MODEL ASSESSMENT REQUIREMENTS

The project proponent may not deviate from the methods provided in this appendix because these methods are not related to monitoring or measurement. This appendix must be followed to select and assess proxy models from sections 9.2.2.2 and 9.2.3.2.

All models must be fit using a sample size of at least 30 measurements.

F.1 Model Selection

A candidate set of models to predict methane or nitrous oxide flux (the response) must be fit using an unbiased estimator of model parameters. All models must be fit to the same response data and covariate data. An estimate of Akaike Information Criterion (AIC) must be used for model selection. The model with the lowest AIC must be used to predict methane and nitrous oxide flux.

F.2 Checking Assumptions

The assumptions of the statistical methods used to fit the selected model must be listed. If ordinary least squares (OLS) is used to fit the model, this statistical method assumes the following:

1. Residuals are uncorrelated.
2. Residuals are homoscedastic.
3. Residuals are independent of each other.
4. Residuals are normally distributed.

The assumptions of the statistical method must be confirmed on the basis of sampling design, statistics and diagnostic plots. Diagnostic plots must be used to check for 'outlier' data points, which must be included in the model fitting unless they are determined to be erroneous. If the assumptions of the statistical method are not confirmed, then in some cases, a correction factor may be required. The correction factor must be applied from peer-reviewed literature or a statistical publication.

The selected model must not be used if the assumptions of the model are unconfirmed or if an appropriate correction factor has not been applied.

F.3 Determining Goodness of Fit

Goodness of fit must be determined based on the parameter values of the selected model. The parameter estimates must be unbiased and predictions must be monotonic on the interval of the range of plausible predicted emissions. The covariate and response data used to parameterize the model must be obtained per the requirements of Sections 9.2.2.3 or 9.2.3.3 to ensure conservativeness of model predictions. Because data for the parameterization of the model is derived from conservative measurements as described in these sections, there are no requirements on the precision of the model predictions or parameter estimates.

F.3.1 Estimates of Parameter Bias

Leave-one-out cross validation must be used to estimate the bias of parameter estimates. The estimated bias must not exceed 15% of the estimated parameter value, on average across parameters.

F.3.2 Confirmation of Monotonicity

In order to confirm that the selected model is conservative, the project proponent must provide graphical plots of the model predictions across the range of plausible input covariate values. Within this range, the function must be monotonic—that is, predictions must not change concavity and be increasing throughout the range of plausible predicted emissions. For example, if the function is increasing at a decreasing rate, it must continue to increase at a decreasing rate across the interval of plausible predicted emissions.

APPENDIX G: EQUATIONS IN METHODOLOGY

$$d_{P\,\Delta}^{[m]} = {p_{SLD}}^{[m]} d_{SLD}^{[m]} + (1 - {p_{SLD}}^{[m]}) d_{LQD}^{[m]}$$ [G.1]	
Variables	$\boldsymbol{d_{P\,\Delta}^{[m]}}$, $\boldsymbol{{p_{SLD}}^{[m]}}$, $\boldsymbol{d_{SLD}^{[m]}}$, $\boldsymbol{d_{LQD}^{[m]}}$
Section References	9.2.5
Comments	Density of sediment dredged from sediment source.

$$M_{P\,\Delta}^{[m]} = \frac{V_{P\,\Delta}^{[m]} d_{P\,\Delta}^{[m]}}{1000}$$ [G.2]	
Variables	$\boldsymbol{M_{P\,\Delta}^{[m]}}$, $\boldsymbol{V_{P\,\Delta}^{[m]}}$, $\boldsymbol{d_{P\,\Delta}^{[m]}}$
Section References	9.2.5
Comments	Mass of sediment dredged from the sediment source as a result of project activities.

$$E_{B\,\Delta\,EC}^{[m]} = -M_{P\,\Delta}^{[m]} \sum_{(ty)\in\mathcal{T}_{B\,EC}} e_{(ty)}\, g_{B\,(ty)}$$ [G.3]	
Variables	$\boldsymbol{E_{B\,\Delta\,EC}^{[m]}}$, $\boldsymbol{M_{P\,\Delta}^{[m]}}$, $\boldsymbol{e_{(ty)}}$, $\boldsymbol{g_{B\,(ty)}}$
Section References	8.1.1
Comments	Total baseline emissions from energy consumption in the monitoring period (tCO_2e).

$$F_{B\,\Delta\,CH4}^{[m]} = A_{PA} \times f_{B\,\Delta\,CH4}^{[m]}$$ [G.4]	
Variables	$\boldsymbol{F_{B\,\Delta\,CH4}^{[m]}}$, $\mathrm{A_{PA}}$, $\boldsymbol{f_{B\,\Delta\,CH4}^{[m]}}$
Section References	8.1.2, 9.2.2
Comments	Baseline methane emissions flux (tCO_2e/day).

$$E_{B\,\Delta\,CH4}^{[m]} = -\left(t^{[m]} - t^{[m-1]}\right) F_{B\,\Delta\,CH4}^{[m]}$$ [G.5]	
Variables	$\boldsymbol{E_{B\,\Delta\,CH4}^{[m]}}$, $\boldsymbol{t^{[m]}}$, $\boldsymbol{t^{[m-1]}}$, $\boldsymbol{F_{B\,\Delta\,CH4}^{[m]}}$
Section References	8.1.2
Comments	Total baseline methane emissions from methane over monitoring period (tCO_2e).

$$E_{B\,\Delta}^{[m]} = E_{B\,\Delta\,EC}^{[m]} + E_{B\,\Delta\,CH4}^{[m]}$$ [G.6]	
Variables	$\boldsymbol{E_{B\,\Delta}^{[m]}}$, $\boldsymbol{E_{B\,\Delta\,EC}^{[m]}}$, $\boldsymbol{E_{B\,\Delta\,CH4}^{[m]}}$
Section References	8.1
Comments	Total baseline emissions over monitoring period (tCO_2e). (If dredging is not included in the baseline scenario, emissions from energy consumption are zero (see section 6.2); if methane ebullition is not included in the baseline scenario, methane emissions are zero.)

$$C_{P\,CS}^{[m]} = \sum_{(c)\in\mathcal{C}} C_{P\,CS\,(c)}^{[m]}$$	[G.7]
Variables	$\boldsymbol{C_{P\,CS}^{[m]}}$, $\boldsymbol{C_{P\,CS\,(c)}^{[m]}}$
Section References	9.2.1, 9.2.1.1
Comments	Cumulative carbon stocks in project area at end of monitoring period.

$$E_{P\,\Delta\,CS}^{[m]} = C_{P\,CS}^{[m]} - C_{P\,CS}^{[m-1]} - 0.131 E_{P\,\Delta\,CH4}^{[m]}$$	[G.8]
Variables	$E_{P\,\Delta\,CS}^{[m]}$, $\boldsymbol{C_{P\,CS}^{[m]}}$, $\boldsymbol{C_{P\,CS}^{[m-1]}}$, $\boldsymbol{E_{P\,\Delta\,CH4}^{[m]}}$,
Section References	8.2.1
Comments	Total carbon stock emissions or emissions reductions and/or removals in the project area for the monitoring period (tCO_2e). For the first monitoring period $C_{P\,CS}^{[m-1]} = C_{P\,CS}^{[m=0]}$ or the carbon stocks in the project area prior to the project start date. Last term in equation ($0.131 E_{P\,\Delta\,CH4}^{[m]}$) is included in order to avoid double-counting of sequestered carbon that subsequently was released as a methane flux. The coefficient (0.131) represents a conversion for the differences in mass (44 CO_2 = 16 CH_4) and global warming potential (1 CO_2 = 21 CH_4): 1 ton CO2 = (44/16)*(1/21) = 0.131.

$$E_{P\,\Delta\,CS}^{[m]} = -0.131E_{P\,\Delta\,CH4}^{[m]} + \sum_{(i)\in\mathcal{G}} C_{P\,CS\,(i)}^{[m]} - C_{P\,CS\,(i)}^{[m-1]}$$ [G.9]	
Variables	$\boldsymbol{E_{P\,\Delta\,CH4}^{[m]}}$, $\boldsymbol{C_{P\,CS}^{[m-1]}}$, $\boldsymbol{C_{P\,CS}^{[m]}}$ $\boldsymbol{E_{P\,\Delta\,CS}^{[m]}}$
Section References	8.2.1
Comments	Total carbon stock emissions or emissions reductions and/or removals in the project area for the monitoring period for project activity instances in a grouped project (tCO_2e). First term in equation ($0.131E_{P\,\Delta\,CH4}^{[m]}$) is included in order to avoid double-counting of sequestered carbon that subsequently was released as a methane flux. The coefficient (0.131) represents a conversion for the differences in mass (44 CO_2 = 16 CH_4) and global warming potential (1 CO_2 = 21 CH_4): 1 ton CO2 = (44/16)*(1/21) = 0.131.

$$F_{P\,\Delta\,CH4}^{[m]} = A_{PA} \times f_{P\,\Delta\,CH4}^{[m]}$$ [G.10]	
Variables	$\boldsymbol{F_{P\,\Delta\,CH4}^{[m]}}$, $\boldsymbol{A_{PA}}$, $\boldsymbol{f_{P\,\Delta\,CH4}^{[m]} F_{P\,\Delta\,CH4}^{[m]}}$
Section References	8.2.2, 9.3.2.3
Comments	Methane emissions flux within project area (tCO_2e/day).

$$E^{[m]}_{P\,\Delta\,CH4} = -\left(t^{[m]} - t^{[m-1]}\right)F^{[m]}_{P\,\Delta\,CH4}$$ [G.11]	
Variables	$\boldsymbol{E^{[m]}_{P\,\Delta\,CH4}}$, $\boldsymbol{t^{[m]}}$, $\boldsymbol{t^{[m-1]}}$, $\boldsymbol{F^{[m]}_{P\,\Delta\,CH4}}$
Section References	8.2.2, 9.2.2, 9.2.2.1
Comments	Total methane emissions in project area over monitoring period (tCO_2e).

$$F^{[m]}_{P\,\Delta\,N2O} = A_{PA} \times f^{[m]}_{P\,\Delta\,N2O}$$ [G.12]	
Variables	$\boldsymbol{F^{[m]}_{P\,\Delta\,N2O}}$, $\boldsymbol{A_{PA}}$, $\boldsymbol{f^{[m]}_{P\,\Delta\,N2O}}$
Section References	9.3.3.3
Comments	Nitrous oxide emissions flux within project area (tCO_2e/day).

$$E^{[m]}_{P\,\Delta\,N2O} = -\left(t^{[m]} - t^{[m-1]}\right)F^{[m]}_{P\,\Delta\,N2O}$$ [G.13]	
Variables	$\boldsymbol{E^{[m]}_{P\,\Delta\,N2O}}$, $\boldsymbol{t^{[m]}}$, $\boldsymbol{t^{[m-1]}}$, $\boldsymbol{F^{[m]}_{P\,\Delta\,N2O}}$
Section References	8.2.3, 9.2.3, 9.2.3.1
Comments	Total nitrous oxide emissions in project area over monitoring period (tCO_2e).

$$E_{P\,\Delta\,EC}^{[m]} = -\sum_{(ty)\in\mathcal{T}_{P\,EC}} G_{P\,\Delta\,(ty)}^{[m]} e_{(ty)}$$	[G.14]
Variables	$\boldsymbol{E_{P\,\Delta\,EC}^{[m]}}$, $\boldsymbol{G_{P\,\Delta\,(ty)}^{[m]}}$, $e_{(ty)}$
Section References	8.2.4
Comments	Total emissions from energy consumption in project area over monitoring period (tCO_2e).

$$E_{P\,\Delta}^{[m]} = E_{P\,\Delta\,CS}^{[m]} + E_{P\,\Delta\,CH4}^{[m]} + E_{P\,\Delta\,N2O}^{[m]} + E_{P\,\Delta\,EC}^{[m]}$$	[G.15]
Variables	$\boldsymbol{E_{P\,\Delta}^{[m]}}$, $\boldsymbol{E_{P\,\Delta\,CS}^{[m]}}$, $\boldsymbol{E_{P\,\Delta\,N2O}^{[m]}}$, $\boldsymbol{E_{P\,\Delta\,CH4}^{[m]}}$, $\boldsymbol{E_{P\,\Delta\,EC}^{[m]}}$
Section References	8.2
Comments	Total emissions or emissions reductions and/or removals in project area over monitoring period (tCO_2e).

$$E_{GER\,\Delta}^{[m]} = E_{P\,\Delta}^{[m]} - E_{B\,\Delta}^{[m]}$$	[G.16]
Variables	$\boldsymbol{E_{GER\,\Delta}^{[m]}}$, $\boldsymbol{E_{B\,\Delta}^{[m]}}$, $\boldsymbol{E_{P\,\Delta}^{[m]}}$
Section References	8.4.1
Comments	Total gross emissions reductions and/or removals over monitoring period (tCO_2e).

$$E_{GER}^{[m]} = \sum_{m \in \mathcal{M}} E_{GER\,\Delta}^{[m]}$$	[G.17]
Variables	$\boldsymbol{E_{GER}^{[m]}}$, $\boldsymbol{E_{GER\,\Delta}^{[m]}}$ $\boldsymbol{E_{GER\,\Delta}^{[m]}}$
Section References	8.4.1.1
Comments	Cumulative gross emissions reductions and/or removals over monitoring period (tCO_2e).

$$U_{P\,CS}^{[m]} = \sqrt{\sum_{(c) \in \mathcal{C}} \left(U_{P\,CS\,(c)}^{[m]}\right)^2}$$	[G.18]
Variables	$\boldsymbol{U_{P\,CS}^{[m]}}$, $\boldsymbol{U_{P\,CS\,(c)}^{[m]}}$
Section References	8.4.2.1
Comments	Total standard error of carbon stocks over monitoring period (tCO_2e).

$$E_{U\,\Delta}^{[m]} = E_{GER\,\Delta}^{[m]} \left[\frac{1.645 \times U_{P\,CS}^{[m]}}{C_{P\,CS}^{[m]}} - 0.15\right]$$	[G.19]
Variables	$\boldsymbol{E_{U\,\Delta}^{[m]}}$, $\boldsymbol{E_{GER\,\Delta}^{[m]}}$, $\boldsymbol{U_{P\,CS}^{[m]}}$, $\boldsymbol{C_{P\,CS}^{[m]}}$
Section References	8.4.2.1
Comments	Confidence deduction for monitoring period (tCO_2e). This quantity must be greater than or equal to zero.

$$E_{BA\,\Delta}^{[m]} = b^{[m]} E_{P\,\Delta\,CS}^{[m]}$$ [G.20]	
Variables	$\boldsymbol{E_{BA\,\Delta}^{[m]}}$, $\boldsymbol{b^{[m]}}$, $\boldsymbol{E_{P\,\Delta\,CS}^{[m]}}$
Section References	8.4.2.2
Comments	Total emissions reductions and/or removals allocated to AFOLU pooled buffer account over monitoring period.

$$E_{NER\,\Delta}^{[m]} = E_{GER\,\Delta}^{[m]} - E_{U\,\Delta}^{[m]} - E_{BA\,\Delta}^{[m]} + E_{BR\,\Delta}^{[m]}$$ [G.21]	
Variables	$\boldsymbol{E_{NER\,\Delta}^{[m]}}$, $\boldsymbol{E_{GER\,\Delta}^{[m]}}$, $\boldsymbol{E_{U\,\Delta}^{[m]}}$, $\boldsymbol{E_{BA\,\Delta}^{[m]}}$, $\boldsymbol{E_{BR\,\Delta}^{[m]}}$
Section References	8.4.2
Comments	Total net emissions reductions and/or removals over monitoring period (tCO_2e).

APPENDIX H: SUPPORTING INFORMATION ON DEVELOPMENT OF POSITIVE LIST

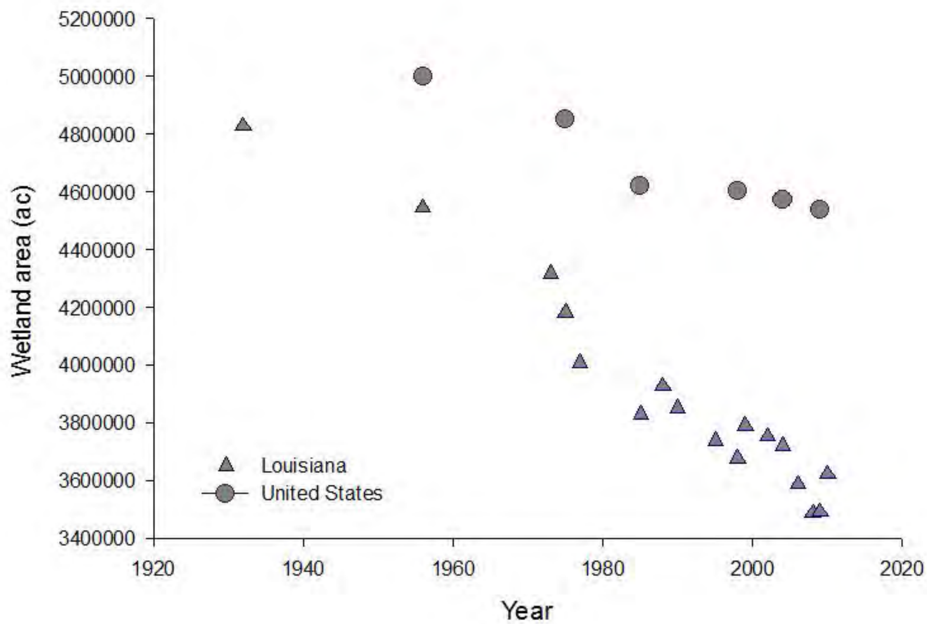
The methodology specifies a positive list for additionality based on activity penetration in specific geographic scopes. The level of activity penetration for a project activity in a given geographic region is determined using appropriate credible data, including from federal agencies (eg, USACE, USGS, USFWS). In order to define the activity and geographic scope for the positive list, the methodology developer demonstrated both the maximum adoption potential and the observed adoption of the project activity (eg, the number and extent of the activity which has been implemented). The calculated level of activity penetration of RWE project activities is currently determined to be less than 5 percent and the level of activity penetration of ARR+RWE project activities meeting the applicability conditions of this methodology is negligible.

The maximum adoption potential takes into account the relevant factors affecting the adoption of the activity within the applicable geographic scope, including implementation potential (ie, the extent of wetland loss within the geographic scope), resource availability (ie, the local supply of dredged sediments), technological capacity (ie, the amount of locally available dredging equipment), level of service (ie, the availability of dredging equipment), socio-economic conditions (ie, the presence of competing economic activities occurring in the coastal zone), and climatic conditions (ie, the incidence of hurricanes and extreme tidal fluctuations). In the case of socio-economic conditions and competing economic activities (eg, oyster farming), the methodology developers concluded that such competing activities are not common enough to limit or displace coastal wetland reestablishment activities, and moreover such economic activities do not vary significantly among regions within the geographic scope. The methodology developers also considered the spatial heterogeneity of climate conditions across the geographic scope, and concluded that regardless of the likelihood of such extreme climate events, the project proponent must demonstrate a long-term trend of wetland loss (see section 6.1). Further, once a project has been established, the methodology ensures that the impacts of a climate event will be captured by the monitoring activities and will be reflected in the carbon accounting. Maximum adoption potential does not consider cost of adoption, cultural or behavioral barriers, and laws, statues, regulatory frameworks or policies.

H.1 Synopsis

This methodology deems project activities as additional, and qualifies them for a positive list based on low rates of adoption in the United States. The total need or adoption potential for coastal wetland creation is conservatively ~1.482 million ac, based on historic loss in the lower 48 states since the 1930's (Figure 1). Approximately 2.7% (39,834) ac of the total coastal wetlands lost in the U.S. has been rebuilt. Therefore, creation of wetlands as described in this methodology, for both RWE and ARR+RWE projects, is deemed additional in accordance with VCS requirements.

Figure 1: Estimates of estuarine vegetated wetland in the U.S. and coastal land area in Louisiana



The following sections—*Analysis* and *Supporting Technical Information*—present the adoption potential analysis and summaries of national and region-specific wetland changes and creation efforts.

H.2 Analysis

This analysis demonstrates that the level of "activity penetration" for creation of coastal wetlands is currently much less than 5%. Substantial needs exist for rebuilding of wetlands lost due to various direct and indirect anthropogenic factors. However, due to funding constraints only a small fraction of the need has been satisfied as of the completion of this methodology.

The positive list for activities established under this methodology is based on a demonstration that the project activities have achieved a low level of penetration relative to their maximum adoption potential, in accordance with VCS requirements. This activity penetration level is estimated using the following equation:

$$AP_y = OA_y / MAP_y$$

Where,

AP_y =	Activity penetration of the project activity in year y (percentage)
OA_y =	Observed adoption of the project activity in year y (eg, total number of instances installed at a given date in year y, or amount of energy supplied in year y)
MAP_y =	Maximum adoption potential of the project activity in year y (eg, total number of instances that potentially could have been installed at a given date in year y, or the amount of energy that potentially could have been supplied in year y)

The following analysis estimates penetration level, current as of 2012, for the conterminous United States. Since a key location for application of this methodology is Louisiana, it will also be demonstrated using state-specific data.

Given adequate time and funding, adequate supplies of sediment for wetland are available, either from rivers or nearshore/offshore locations where they are routinely dredged. Resource availability is not a constraint. As an ecosystem restoration activity, total demand, market access, and market price are not relevant factors in this analysis. Implementation potential is the need for wetland restoration and is therefore considered equal to maximum adoption potential.

In order to arrive at a conservative estimate for the maximum adoption potential, data from two studies are used. The first (Couvillion et al. 2012) provides data from Louisiana only and indicates that total coastal wetland loss in Louisiana amounted to 1,205,120 ac. This study provides a comprehensive and detailed estimate of wetland loss, including both coastal fresh and saltwater wetlands. The second is a national level study (Dahl 2000, 2006, 2011) that estimates total U.S. wetland loss of 461,000 ac, but includes only estuarine vegetated wetlands, thus excluding the losses of tidal freshwater wetlands. Because coastal Louisiana loss is commonly accepted to be 40% of the national total, the national vegetated estuarine wetland loss excluding Louisiana was estimated at 276,000 ac. Adding in the long-term historic wetland loss in Louisiana of 1,205,120 ac with the less-comprehensive national estimate of 276,000 ac yields 1,481,720 ac. The two studies used to derive the maximum adoption potential are described in more detail below.

Based on USGS data (Couvillion et al. 2012), approximately 1.205 million acres of Louisiana's coastal wetlands have been lost and converted to open water since the 1930's. Louisiana's Coastal Protection and Restoration Authority (CPRA) has tracked engineered wetland creation projects by the State, in addition to USACE beneficial use projects. CPRA estimates that approximately 16,137 acres have been created since 2005, including both the State's projects and USACE beneficial use projects (Table H3, *Supporting Technical Information*). Therefore, the current level of activity penetration in Louisiana is approximately 1.3% (16,137 ac created/1,205,000 ac lost).

At a national scale, the U.S. Fish & Wildlife Service Status & Trends reports (Dahl 2000, 2006, 2011) estimate that 461,000 acres of vegetated estuarine wetlands have been lost since the 1950s (Table H2, *Supporting Technical Information).* This estimate excludes the losses of tidal freshwater wetlands, which results in a conservative (underestimate) of total tidal and estuarine wetland loss (tidal freshwater wetlands are now reported as 'Palustrine,' which typically includes all inland freshwater systems). For example, a more detailed analysis by Stedman and Dahl (2008) showed that the *coastal watersheds* of the Gulf of Mexico and the Atlantic states lost a total of 370,760 ac and 14,980 ac, respectively, of freshwater and saltwater wetlands.

Given that total coastal wetland creation as described in Section H.3.5 was 39,834 ac and the maximum adoption potential is 1,481,720 ac, the resulting activity penetration level is approximately 2.7%. With observed adoption less than the need for replacement of wetlands, adoption potential is below the 5% threshold set by VCS requirements. Therefore, coastal wetland creation projects are deemed additional.

H.3 Supporting Technical Information

H.3.1 Estuarine Vegetated Wetland Loss in the United States

Estuarine vegetated wetland loss in the United States since the 1950's to 2009 has been estimated at approximately 461,000 ac (Table H1). Based on the most recent analysis from 2004-2009 (Dahl 2011), approximately 111,000 ac of estuarine vegetated wetlands were lost over the 4.5 year period, or approximately 25,000 ac/yr.

Wetland loss prior to the 1980's may have included direct conversion of wetlands to agriculture and coastal development. Since the 1980's, however, conversion of wetlands to deep open water has been responsible for wetland losses, as excerpted from Dahl's analyses:

> "[The 1998-2004 rate of loss] *was consistent with the rate of salt marsh loss recorded from 1986 to 1997 (Dahl 2000). Urban and rural development activities, and the conversion of wetlands to other upland land uses, accounted for an estimated loss of 1,732 acres (700 ha) or about 3.0 percent of all losses of estuarine emergent wetland. Most of the losses of estuarine emergent wetland were due to loss to deep salt water and occurred in coastal Louisiana*." (Dahl 2006)
>
> "[The 2004-2009 rate of loss] *of intertidal emergent wetland increased to three times the previous loss rate between 1998 and 2004. The majority of these losses (83%) was to deepwater bay bottoms or open ocean.*"

H.3.2 Vegetated Wetland Loss in Coastal Watersheds in the Atlantic and Gulf of Mexico

An analysis of *coastal watershed* vegetated wetland changes in the eastern United States (1998-2004) (Stedman and Dahl 2008) showed that the Gulf of Mexico and Atlantic states had net wetland losses in coastal watersheds totaling 370,760 ac and 14,980 ac, respectively, when including both fresh and saltwater wetlands. Total saltwater vegetated wetland loss was 64,970 ac, of which 96% (or 62,370 ac) was conversion to open saltwater.

Table H1: Historic and contemporary estimates of estuarine vegetated wetland acreage since the mid-1950's for the United States and Atlantic/Gulf of Mexico regions based on similar mapping techniques

Time period	**Conterminous US** Estuarine vegetated wetland (ac) (Dahl 2006, Dahl 2011)	**Atlantic Coastal Watershed** Vegetated wetland (ac) (Stedman and Dahl 2008)	**GOM Coastal Watershed** Vegetated wetland (ac) (Stedman and Dahl 2008)
1950's	5,000,000		
1970's	4,854,000		
1980's	4,623,000		
1998	4,604,200	1,842,320	3,108,110
2004	4,571,700	1,822,780	3,062,680
2009	4,539,700		
Notes	US wetland loss (1950's-2009) 461,000 ac	Atlantic wetland loss (98-04) 19,540 ac	GOM wetland loss (98-04) 45,430 ac

H.3.3 Wetland Loss in Louisiana

The most recent study by Couvillion et al. (2012) summarized wetland loss during 1932-2010 and intervals in between. Cumulative wetland loss in Louisiana from 1932-2010 was estimated at 1,205,120 ac. Trend analyses of comparable satellite imagery were limited to the 1985-2010[4] time period, which showed a loss rate of 10,605 ac/yr.

H.3.4 Proportion of Coastal Wetland Loss in Louisiana Compared to the U.S.

Based on a number of analyses, Louisiana wetland loss has been commonly accepted to be ~ 40% of the national total. This is supported by the recent analyses by Couvillion et al. (2012) and Dahl (2011), which showed that the annual loss rate in Louisiana (-10,605 ac/yr, from 1985-2010) was 42% of the national rate (-25,000 ac/yr 2004-2009).

[4] The calculation of wetland loss rates in Louisiana is sensitive to water level during imagery acquisition. More recent and frequent satellite imagery has allowed for a large number of images to be analyzed and reduced uncertainty.

H.3.5 Wetland Creation in the United States and Louisiana

The most significant nationwide wetland creation effort has been accomplished with beneficial placement of dredged sediments by the USACE (Table H2). More recently, a state wetland creation program has been developed in Louisiana by the Coastal Protection and Restoration Authority (CPRA) (Table H3).

Including Louisiana, marsh creation and nourishment by the USACE has totaled approximately 32,355 ac from 2007-2012 (Table H2). There are several reasons why these data produce a conservative overestimate of actual wetland creation. First, the USACE presents both wetland 'creation' and 'nourishment' together. Second, there are 11 non-coastal districts which are included in the statistics presented in Table H2 (although the non-coastal districts comprise only 5 percent of the total dredging conducted by the USACE). Third, the assumed conversion value of 1 ac = 6,250 CY may be low for some areas. For example, the actual CY of sediment needed for an acre of wetland creation ranges from approximately 6,000 CY to 16,000 CY (calculated from data in Table H3).

In Louisiana, engineered wetland creation projects have been tracked more precisely than USACE nationwide projects. Based on CPRA's data set, approximately 7,479 ac of wetlands have been created in Louisiana during FY 2005-2012 Table H3), not including the USACE's beneficial use projects (which are included in Table H2).

Combining both data sets results in an estimate of 39,834 ac (nationwide USACE = 32,355 ac; Louisiana state projects = 7,479 ac) of wetland creation and nourishment that has occurred nationwide through efforts of the USACE and the State of Louisiana, which comprise the most significant sources of wetland creation with dredged material.

Table H2: Estimated nationwide USACE wetland creation and nourishment from both coastal and non-coastal areas of the U.S. Acreage estimates are derived from dredge disposal statistics from the USACE Navigation Data Center: http://www.navigationdatacenter.us/dredge/drgdisp.htm (Disposal Type = Wetland Creation and Nourishment). For more information, contact U.S. Army Corps of Engineers, CEIWR-NDC, 7701 Telegraph Road, Casey Bldg., Alexandria, Virginia 22315-3868, point of contact: NDC (703) 428-9061**.**

Year	**Contracts**	**Cubic Yards (Bid)**	**Dollars (Bid)**	**Estimated Acres[5]**
2007	9	38,075,031	$69,878,722	6,092
2008	9	49,108,000	$55,467,694	7,857

[5] Assumes that 6,250 CY of sediment is needed to create one acre of wetland, based on USACE, 2006, Louisiana Coastal Area Beneficial Use of Dredge Material: http://www.lca.gov/Studies/budmat.aspx.

2009	7	25,582,361	$56,902,237	4,093
2010	9	37,481,966	$107,437,192	5,997
2011	6	17,705,385	$28,221,454	2,833
2012	8	34,263,868	$94,759,277	5,482
			Estimated Total	32,355 ac

Table H3: Wetland creation acreage constructed in Louisiana during FY2005-2012 by CPRA and USACE (data courtesy of CPRA)

	Louisiana (Federal/State/Other)		Louisiana (USACE Beneficial Use)		Total
Year	CY	AC	CY	AC	AC
2004-2005	244,441	26	14,686,790	515	541
2005-2006	0	0	9,286,170	604	604
2006-2007	6,099,372	920	16,018,350	1,228	2,148
2007-2008	1,593,629	262	8,726,625	522	784
2008-2009	11,653,148	1,350	8,134,849	248	1,598
2009-2010	21,303,000	3,483	19,613,374	1,591	5,074
2010-2011	6,300,000	94	27,325,000	2,514	2,608
2011-2012	16,764,560	1,344	15,125,000	1,437	2,781
Total	63,958,150	7,479	118,916,158	8,658	**16,137**

H.4 References

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APPENDIX I: JUSTIFICATION FOR THE EXCLUSION OF ALLOCHTHONOUS CARBON IN THE LOUISIANA COASTAL ZONE

I.1 Introduction

Many estuarine wetlands are exporters or sources of carbon to the continental shelf, typically termed 'carbon outwelling'. Net burial of carbon in tidal wetland soils is usually on the order of <200 g C/m^2/yr (McLeod et al. 2011), while an excess of 100-200 g C/m^2/yr of carbon is exported to inshore and offshore areas (Nixon 1980; also see Table 1). The source, transport and fate of carbon along the estuary-offshore gradient are complicated processes, but largely, estuarine wetland systems are typically understood as carbon sources to estuarine-offshore systems. High energy, macrotidal salt marshes may receive substantial mineral sediments (and associated carbon) near the mouth of the estuary. The source of carbon may come from upland habitats, which may be replenished, or within the estuarine system as wetlands are eroded or reworked.

Stevenson et al. (1988) raised the consideration of sea level rise and sediment supply as to why estuaries—especially southern microtidal systems—are susceptible to wetland loss. In addition to sea level rise, the authors maintain that sediment starvation through reductions in terrigenous sediment sources is a key factor of undernourishment of wetlands:

> From Stevenson et al. 1988*: Differences in tidal dynamics, seasonal changes in sea levels and higher temperatures may help explain why, in the U.S., southern marshes are more susceptible to export and eventual erosion than northern marshes. We hypothesize that another factor, the recent reductions of terrigenous sediment inputs from the southern river systems of the U.S., may also be critical. Sediment starvation may have led to undernourishment of wetland systems of the coastal zone over the last half century which may be reflected in the net export measured in the tidal marshes in this region. Furthermore, we postulate that changes in sediment inputs are more important than eustatic sea level rise in causing the past losses of marshes which are now undergoing mass erosion.*

There has been a systemic reduction in sediment delivery to coastal wetlands nationwide due to changes in land-use (European settlement and land clearing) and expansion of dam building on major rivers (Syvitski et al. 2009). The Chesapeake Bay area and Louisiana delta serve as examples of the observed modern sediment-driven degradation of wetlands to open water (Kirwan et al. 2011).

I.2 Support from the Literature

The literature from coastal Louisiana broadly supports the understanding that its wetlands are sources of carbon to the Gulf of Mexico (see estimates in Table I.1). Moreover, in the last century there has been a systematic reduction in allochthonous mineral sediment (with its associated carbon) to the wetlands due to construction of levees along the Mississippi River (Blum and Roberts 2009). As a consequence, the estuaries are not receiving substantial external sources of sediments or carbon. The following summary provides a description on carbon exchange in Louisiana estuaries and provides the rationale as to why accounting for the import of carbon to created wetlands projects is not relevant for the coastal region of Louisiana. Namely, there is an absence of real external sources of carbon to the coastal basins, most of the carbon is exchanged among habitats in the coastal basins, and any import of carbon in the project area will be substantially offset by the carbon that the project will export.

1. *Export of Carbon from Louisiana Estuaries*: Louisiana estuaries are ebb-dominated systems exhibiting a consistent pattern of exporting of Particulate Organic Carbon (POC) and Total Organic Carbon (TOC) to the Gulf of Mexico. This has been shown for most of the Louisiana coastal areas, including: Barataria Basin (Li et al. 2011; Das et al. 2010, 2011; Wilson and Allison 2008; Feijtel et al. 1985; Happ et al. 1977), Breton Sound (Wilson and Allison 2008), and Fourleague Bay (Stern et al. 1991; Madden et al., 1988; Perez et al. 2000). Wilson and Allison (2008) estimated that Barataria and Breton Sound estuaries export 3.7 x 10^4 and 4.6 x 10^4 MT POC annually, respectively, and the magnitude of these estimates was corroborated by Das et al. 2011. The magnitude of Dissolved Organic Carbon (DOC) that is exported is six fold greater than particulate forms (Das et al. 2011).

2. *External Sediment Supply Constraints to Louisiana Wetlands*: An allochthonous sediment deficit to Louisiana coastal wetlands occurred following the levee construction along the Mississippi River and persists today (Blum and Roberts 2009). In a review paper of mineral and organic contributions to tidal freshwater wetland accretion from Maine to Louisiana, Neubauer (2008) showed that Louisiana freshwater wetlands exhibited the lowest mineral accumulation rates. Much of the contemporary sediment deposition in Louisiana wetlands is a result of the redistribution of sediment and organic matter within the system. Organic matter (or carbon) can come from upper basin wetlands and be deposited in downstream project areas, or may arrive at the project site from lower in the basin with storms and fronts (Reed 1989). In any case, the source of the carbon comes from either the natural export of surrounding healthy wetlands or from shoreline erosion. DeLaune et al. (2013) described one example of how non-restored wetland erosion can serve as a source of sediments that are transported through the estuary: “as marshes degrade and erode, there is a loss of material through net transport of mineral and organic matter through tidal inlets to the coastal ocean (Li et al 2009, 2011). The translocation of organic and mineral material from the marsh to the coastal waters further exacerbates coastal land loss.”

3. *Carbon Quality, Storage, and Averting Emissions*: Das et al. (2011) proposed that “the fate of carbon from eroded wetlands remains incompletely known” but evidence from their study as well as another recent study (Wilson and Allison, 2008) “potentially suggest that about 40% of POC released from eroding marshes is exported to the coastal Gulf of Mexico”. Thus, organic matter storage is occurring within the estuary’s wetlands and bays. While the fate and transformation of organic matter from interior wetlands to the offshore environment isn’t entirely certain, there is reasonable evidence that the source of allochthonous carbon to a project area in Louisiana will be similar in quality to that which will be released from the project area (Wilson and Allison, 2008). That is, the source of carbon is largely derived within the system. There is also increasing

evidence that Mississippi River water, which could enter from the mouth of adjacent estuaries in Louisiana, has a higher fraction of labile carbon than previously assumed (Mayer et al. 2008).

The design and location of wetland creation projects offer benefits in the form of capturing organic sediments that could otherwise be lost offshore or potentially oxidized in shallow bay waters. The decay of organic matter in the emergent wetland environment is slower than the estuarine open water setting due to the presence of anaerobic conditions, acidic porewater, and the presence of decay inhibitors (secondary metabolic compounds or humic acids) (Bianchi et al. 2011). Along the terrestrial to marine gradient, the likelihood of emissions with organic matter decay is increased as exposure or residence time under oxic conditions is prolonged, a process termed 'diagenetic oxygen exposure time' (Bianchi et al. 2011). The combination of physical energy, photo-degradation, oxygen exposure, and strong ionic gradients can accelerate the carbon decay process along the estuarine-offshore gradient. Thus, under the project condition, allochthonous carbon has a greater likelihood of preservation in the wetland system.

In summary, for Coastal Louisiana, it can be conservatively assumed that transport of organic matter will not cause carbon accretion estimates to be significantly overestimated, and thus allochthonous carbon may be neglected.

Table I.1: Summary of carbon export from estuaries, with special consideration of Louisiana estuaries

Location	Carbon Export[6]	Habitat Type	Source
Review of estuaries	100-200	Salt marshes	Nixon 1980
Barataria Bay, LA	165	Forested upland-estuary interface	Hopkinson and Day 1979
Barataria Bay, LA	150-250	Entire estuary	Feijtel et al. 1985
Barataria Bay, LA	25-540 (150)[7]	Entire estuary	Happ et al. 1977
Barataria Bay, LA	57	Estuary open water area	Das et al. 2010

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[6] Units: g C m^{-2} yr^{-1}

[7] Considering the magnitude of errors involved in the assumptions upon which the calculations were based, the study reported an organic carbon export of 25 to 540 g C m^{-2} yr^{-1} to inshore waters, with the most probable value around 150 g C m^{-2} yr^{-1}.

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APPENDIX J: LIST OF VARIABLES

Data / Parameter	Unit	Description	Source of Data	Measurement Method	Used in Equations	Frequency of Monitoring/ Recording	QA/QC
A_{PA}	acre	Area of project area	GIS analysis prior to sampling		[G.10], [G.12]	-	-
$b^{[m]}$	%	Buffer withholding percentage calculated as required by the VCS AFOLU Non-Permanence Risk Tool	VCS AFOLU Non-Permanence Risk Tool	N/A	[G.20]	Every monitoring period	N/A
$C_{P\ CS}^{[m]}$	tCO_2e	Cumulative project carbon stocks at end of current monitoring period	Sampling activities	[G.7]	[G.8], [G.9], [G.19]	At least every five years	Independent review of equations and check against literature estimates. See Section 9.2.8.3
$C_{P\ CS}^{[m-1]}$	tCO_2e	Cumulative project carbon at beginning of current monitoring period	Sampling activities	[G.7]	[G.8], [G.9]	At least every five years	Independent review of equations and check against literature estimates. See Section 9.2.8.3
$C_{P\ CS\ (c)}^{[m]}$	tCO_2e	Cumulative project carbon in pool *c* at end of current monitoring period	Sampling activities	Appendix D	[G.7]	At least every five years	Independent review of equations and check against literature estimates. See Section 9.2.8.3

Data / Parameter	Unit	Description	Source of Data	Measurement Method	Used in Equations	Frequency of Monitoring/ Recording	QA/QC
$d_{LQD}^{[m]}$	kg/m^3	Density of liquid in dredged sediment	Monitoring records, direct measureme nt	9.2.5	[G.1]	Every monitoring period when sediment is transported	Compare data from multiple samples. See Section 9.2.8.1
$d_{SLD}^{[m]}$	kg/m^3	Density of solids in dredged sediment	Monitoring records. direct measureme nt	9.2.5	[G.1]	Every monitoring period when sediment is transported	Compare data from multiple samples. See Section 9.2.8.1
$d_{P\,\Delta}^{[m]}$	kg/m^3	Density of sediment dredged from sediment source	Monitoring records, direct measureme nt	9.2.5	[G.2], [G.1]	Every monitoring period when sediment is transported	Compare data from multiple samples. See Section 9.2.8.1
$E_{BA\,\Delta}^{[m]}$	tCO_2e	Emissions reductions and/or removals allocated to AFOLU pooled buffer account over current monitoring period	Monitoring records	8.4.2	[G.21], [G.20]	Every monitoring period	Independent review of equations and monitoring records. See Section 9.2.8.2
$E_{B\,\Delta}^{[m]}$	tCO_2e	Total baseline emissions over current monitoring period	Monitoring records	8.1	[G.6], [G.16]	Every monitoring period	Independent review of equations and monitoring records. See Section 9.2.8.2

Data / Parameter	Unit	Description	Source of Data	Measurement Method	Used in Equations	Frequency of Monitoring/ Recording	QA/QC
$E^{[m]}_{B\,\Delta\,CH4}$	tCO_2e	Total baseline emissions from methane over current monitoring period	Monitoring records	8.1.2	[G.5]	Every monitoring period	Independent review of equations and monitoring records. See Section 9.2.8.2
$E^{[m]}_{B\,\Delta\,EC}$	tCO_2e	Total baseline emissions from energy consumption over current monitoring period	Monitoring records	8.1.1	[G.6], [G.3]	Every monitoring period when sediment is transported	Independent review of equations and monitoring records. See Section 9.2.8.2
$E^{[m]}_{BR\,\Delta}$	tCO_2e	Total emissions reductions and/or removals for buffer release over current monitoring period	Monitoring records	8.4.2	[G.21]	Every monitoring period	Independent review of calculations and monitoring records. See Section 9.2.8.2
$E^{[m]}_{GER}$	tCO_2e	Cumulative gross emissions reductions and/or removals at end of current monitoring period	Monitoring records	8.4.1.1	[G.17]	Every monitoring period	Independent review of GER calculations. See Section 9.2.8.2
$E^{[m]}_{GER\,\Delta}$	tCO_2e	Total gross emissions reductions and/or removals over current monitoring period	Monitoring records	8.4.1, 8.4.2	[G.16],[G.17], [G.19], [G.20], [G.21]	Every monitoring period	Independent review of GER calculations. See Section 9.2.8.2
$E^{[m]}_{NER\,\Delta}$	tCO_2e	Total net emissions reductions and/or removals over current monitoring period	Monitoring records	8.4.2	[G.21]	Every monitoring period	Independent review of NER calculations. See Section 9.2.8.2

Data / Parameter	Unit	Description	Source of Data	Measurement Method	Used in Equations	Frequency of Monitoring/ Recording	QA/QC
$E_{P\,\Delta}^{[m]}$	tCO_2e	Total project area emissions/ emissions removals over current monitoring period	Monitoring records	8.2	[G.15], [G.16]	Every monitoring period	Independent review of calculations and monitoring records. See Section 9.2.8.2
$E_{P\,\Delta\,CH4}^{[m]}$	tCO_2e	Total methane emissions in project area over current monitoring period	Monitoring records	8.2.2	[G.15],[G.8], [G.9], [G.11]	Every monitoring period	Independent review of calculations and monitoring records. See Section 9.2.8.2
$E_{P\,\Delta\,CS}^{[m]}$	tCO_2e	Total carbon stock emissions or emissions reductions and/or removals in project area over current monitoring period	Monitoring records	8.2.1	[G.15], [G.8], [G.9],	Every monitoring period	Independent review of calculations and monitoring records. See Sections 9.2.8.2 and 9.2.8.3
$E_{P\,\Delta\,EC}^{[m]}$	tCO_2e	Total emissions from energy consumption in project area over current monitoring period	Monitoring records	8.2.4	[G.15], [G.14]	Every monitoring period when sediment is transported	Independent review of calculations and monitoring records. See Section 9.2.8.2
$E_{P\,\Delta\,N2O}^{[m]}$	tCO_2e	Total nitrous oxide emissions within project area over current monitoring period	Monitoring records	8.2.3,	[G.15], [G.13]	Every monitoring period	Independent review of calculations. See Section 9.2.8.2

Data / Parameter	Unit	Description	Source of Data	Measurement Method	Used in Equations	Frequency of Monitoring/ Recording	QA/QC
$e_{(ty)}$	tCO_2e /gal, tCO_2e /scf, tCO_2e /kWh	Emissions coefficient for energy type *ty*	Emission factors in Section 8.1.1, Table 10	Selected from published values	[G.3], [G.14]		
$E_{U\,\Delta}^{[m]}$	tCO_2e	Confidence deduction for current monitoring period	Monitoring records	8.4.2.1	[G.19], [G.21]	Every monitoring period	Independent review of calculations and monitoring records. See Section 9.2.8.2
$f_{B\,\Delta\,CH4}^{[m]}$	tCO_2e /ac/day	Baseline methane emissions flux per unit area	Monitoring records and static chamber or eddy covariance measurement	9.2.7	[G.5]	Every monitoring period	Comparison of data from multiple samples and independent review of calculations. See Sections 9.2.8.1, 9.2.8.4, and 9.2.8.5
$F_{B\,\Delta\,CH4}^{[m]}$	tCO_2e /day	Baseline methane emissions flux	Monitoring records and static chamber or eddy covariance measurement	9.2.7	[G.5]	Every monitoring period	Comparison of data from multiple samples and review of monitoring records. See Sections 9.2.8.1, 9.2.8.4, and 9.2.8.5

Data / Parameter	Unit	Description	Source of Data	Measurement Method	Used in Equations	Frequency of Monitoring/ Recording	QA/QC
$f^{[m]}_{P\,\Delta\,CH4}$	tCO_2e /ac/day	Methane emissions flux per unit area within project area	Monitoring records and static chamber or eddy covariance measurement	9.2.2.3	[G.10]	Every monitoring period	Comparison of data from multiple samples and review of monitoring records. See Sections 9.2.8.1, 9.2.8.4, and 9.2.8.5
$f^{[m]}_{P\,\Delta\,N2O}$	tCO_2e /ac/day	Nitrous oxide emissions flux per unit area within project area	Monitoring records and static chamber or eddy covariance measurement	9.2.3.3	[G.12]	Every monitoring period	Comparison of data from multiple samples and review of monitoring records. See Sections 9.2.8.1, 9.2.8.4, and 9.2.8.5
$F^{[m]}_{P\,\Delta\,CH4}$	tCO_2e /day	Methane emissions flux within project area	Monitoring records and static chamber or eddy covariance measurement	9.2.2.3	[G.11], [G.10]	Every monitoring period	Comparison of data from multiple samples and independent review of calculations. See Sections 9.2.8.1, 9.2.8.4, and 9.2.8.5

Data / Parameter	Unit	Description	Source of Data	Measurement Method	Used in Equations	Frequency of Monitoring/ Recording	QA/QC
$F^{[m]}_{P\,\Delta\,N2O}$	tCO_2e /day	Nitrous oxide emissions flux within project	Monitoring records and direct measurement, default values, or proxy values developed by the project proponent	9.2.3	[G.13], [G.12]	Every monitoring period	Comparison of data from multiple samples and independent review of calculations. See Sections 9.2.8.1, 9.2.8.4, and 9.2.8.5
$g_{B\,(ty)}$	gal/tonne, scf/tonne, kWh/tonne	Energy consumed per metric tonne of sediment dredged in the baseline	Documentation provided by proponent	Direct measurement	[G.3]	-	-
$G^{[m]}_{P\,\Delta\,(ty)}$	gal, scf, kW	Energy consumed in project area for energy type *ty* over current monitoring period	Monitoring records and direct measurement or cost approach	8.2.4	[G.14]	Every monitoring period when sediment is transported	Independent review of calculations and monitoring records. See Sections 9.2.8.1 and 9.2.8.2
$M^{[m]}_{P\,\Delta}$	tonnes	Mass of sediment dredged from the sediment source over current monitoring period	Monitoring records	8.1.1, 9.2.5	[G.3], [G.2]	Every monitoring period when sediment is transported	Project verification and independent review of calculations. See Section 9.2.8.2

Data / Parameter	Unit	Description	Source of Data	Measurement Method	Used in Equations	Frequency of Monitoring/ Recording	QA/QC
$p_{B\,(ty)}$	proportion (unitless)	Proportion of energy for energy type *ty* consumed in the baseline scenario	Documentation provided by proponent	Calculated from direct measurement	[G.3]	-	-
$p_{SLD}{}^{[m]}$	proportion (unitless)	Proportion of solids by weight in the dredged sediment	Sampling activities, direct measurement	9.2.5	[G.1]	Every monitoring period when sediment is transported	Comparison of data from multiple samples and review of monitoring records. See Sections 9.2.8.1 and 9.2.8.2
$t^{[m]}$	days	Elapsed time from project start at the end of the current monitoring period	Monitoring records	N/A	[G.11], [G.13]	Every monitoring period	N/A
$t^{[m-1]}$	days	Elapsed time from project start at the beginning of the current monitoring period	Monitoring records	N/A	[G.11], [G.13]	Every monitoring period	N/A
$U_{P\,CS}^{[m]}$	tCO_2e	Total standard error in project carbon stocks measured during the current monitoring period	Monitoring records	N/A	[G.19], [G.18]	Every monitoring period	Independent review of calculations and monitoring records. See Section 9.2.8.2

Data / Parameter	Unit	Description	Source of Data	Measurement Method	Used in Equations	Frequency of Monitoring/ Recording	QA/QC
$\boldsymbol{U_{P\,CS\,(c)}^{[m]}}$	tCO_2e	Total standard error in project carbon stocks for pool *c* measured during the current monitoring period	Monitoring records	[A.8]	[G.18]	Every monitoring period	Independent review of calculations and monitoring records. See Section 9.2.8.2
$\boldsymbol{V_{P\,\Delta}^{[m]}}$	m^3	Volume of sediment dredged from the sediment source over current monitoring period	Monitoring records	9.2.5	[G.2]	Every monitoring period when sediment is transported	Independent review of calculations and monitoring records. See Section 9.2.8.2

APPENDIX K: SUMMARY OF PROJECT DESCRIPTION REQUIREMENTS

PDR#	Category	Requirements
PDR.1	Applicability Conditions	For each applicability condition, credible evidence in the form of analysis, documentation or third-party reports to satisfy the condition.
PDR.2	GHG Sources	A list of the included GHG sources.
PDR.3	Carbon Pools	A list of the selected carbon pools.
PDR.4	Allochthonous Carbon in Soil Carbon Pool	Narrative justification that the import of organic matter will not cause carbon accretion estimates to be significantly overestimated including citations to case studies, literature or models.
PDR.5	Allochthonous Carbon in Soil Carbon Pool	Description of the dominant sources of sediments with respect to external (ie, fluvial) inputs or internal (within estuary or tidal freshwater wetland) recycling.
PDR.6	Allochthonous Carbon in Soil Carbon Pool	Proximity of the project area with respect to direct fluvial inputs or near-shore sediment sources.
PDR.7	Allochthonous Carbon in Soil Carbon Pool	An annual mass estimate of the total carbon imported or exported from the estuary or tidal freshwater wetland where the project is located.
PDR.8	Allochthonous Carbon in Soil Carbon Pool	Description of the project area with respect to tidal energy (such as flood- or ebb-dominated) or tidal dispersive flux.
PDR.9	Delineating Spatial Boundaries	GIS-based maps of the project area with, at a minimum, the features listed above.
PDR.10	Delineating Spatial Boundaries	Documentation that the entire project area is/was open water at the project start date.
PDR.11	Delineating Spatial Boundaries	Evidence that the project area meets the definition of tidal or estuarine open water wetlands which once supported emergent wetland vegetation.
PDR.12	Delineating Spatial Boundaries	Evidence that the project area is compliant with the most current version of the VCS AFOLU Requirements regarding the clearing of native ecosystems.
PDR.13	Delineating Spatial Boundaries	If emissions from methane are included in the baseline scenario, an estimate of the average water depth in the project area prior to the implementation of project activities (see Section 6.3).
PDR.14	Delineating Spatial Boundaries	Documentation that the project proponent has control over the project area as described in most recent version of the VCS AFOLU Requirements, Section 3.4.
PDR.15	Delineating Spatial Boundaries	Documentation of the assessment of effects to hydrologically connected areas as further

		described in Section 8.3.1.
PDR.16	Delineating Spatial Boundaries	Documentation of projected sea level rise in the vicinity of the project area, evidence that existing landforms or constructed features are expected to withstand project sea level rise, and a description of the post-construction soil surface elevation relative to mean sea level.
PDR.17	Temporal Project Boundaries	The project start date.
PDR.18	Temporal Project Boundaries	The project crediting period start date and length.
PDR.19	Temporal Project Boundaries	The date by which mandatory baseline reassessment must occur after the project start date.
PDR.20	Temporal Project Boundaries	A timeline including the first anticipated monitoring period showing when project activities will be implemented.
PDR.21	Temporal Project Boundaries	A timeline for anticipated subsequent monitoring periods.
PDR.22	Grouped Projects	A list and descriptions of all enrolled project activity instances in the group at the time of validation.
PDR.23	Grouped Projects	A map of the designated geographic area within which all project activity instances in the group may be located, indicating that all instances are in the same region.
PDR.24	Grouped Projects	A list of eligibility criteria for project activity instances.
PDR.25	Baseline Scenario	Results of a comparative assessment of the implementation barriers and net benefits faced by the project and its alternatives, and justification for the most plausible baseline scenario.
PDR.26	Baseline Scenario	Documentation to demonstrate that the project area previously met the definition of a wetland before converting to open water or similar degraded state. Documentation must include hydrological data to show evidence of long-term patterns of wetland loss.
PDR.27	Baseline Scenario	The selected method for demonstrating the baseline scenario in the project area (regional land use change or spatial analysis).
PDR.28	Regional Land Use Change For Baseline Scenario	A reference to the document providing evidence of continued land loss or static condition in the basin for a period of 10 years prior to the project start date.
PDR.29	Regional Land Use Change For Baseline Scenario	A summary of the referenced document indicating where in the document the evidence is provided.
PDR.30	Regional Land Use Change For Baseline Scenario	Documentation of water management activities (eg, river diversions) that could influence the baseline scenario.
PDR.31	Spatial Analysis for Baseline Scenario	A report describing how the analysis was conducted, including data sources and dates, demonstration of conformance with the requirements listed in Section 6.1.2, and justification

		for the selection of the region in which the analysis was conducted.
PDR.32	Spatial Analysis for Baseline Scenario	A map of the region in which the analysis was conducted.
PDR.33	Spatial Analysis for Baseline Scenario	The quantified change in water area.
PDR.34	Determination of Dredging	Determination (yes or no) whether dredging is included in the baseline scenario.
PDR.35	Determination of Dredging	If dredging is included in the baseline scenario, a description of the single event or programmatic dredging projects, including the likely fate of dredged sediments in the baseline scenario.
PDR.36	Demonstration of Navigability	Map of dredging activities, including justification for planned dredging locations.
PDR.37	Demonstration of Navigability	Documents that demonstrate dredging would have occurred.
PDR.38	Determination of Baseline Energy Consumption	For each energy type in Table 11, the estimate of the unit of energy consumed per metric tonne of sediment dredged.
PDR.39	Determination of Baseline Energy Consumption	Description of equipment types and method or process of sediment dredging, transport, disposal, re-handling, sediment production rates, duration of operations and conveyance distances.
PDR.40	Determination of Baseline Energy Consumption	Estimates of cumulative sediment quantity excavated and re-handled, including temporary disposal and displacement activities, if applicable.
PDR.41	Determination of Baseline Energy Consumption	Source of procedures or data on which these estimates are based.
PDR.42	Determination of Baseline Methane Emissions	Description and justification for the selected reference area.
PDR.43	Demonstration of Project Additionality	Demonstration that pertinent laws and regulations have been reviewed and that none mandate the project activities.
PDR.44	Demonstration of Project Additionality	Evidence that project activities comply with all applicability conditions set out under Section 4.
PDR.45	Emissions or Emissions Reductions and/or Removals Events in Project Area	The selected definition of a significant disturbance.
PDR.46	Hydrologic Effects	Description of the expected impacts on hydrologically connected areas, and the agency process which is expected to take place prior to the commencement of project activities.
PDR.47	Monitoring Plan	A summary of carbon stock sampling procedures for the project area, with a copy of a sampling protocol used by field personnel to carry out measurements.
PDR.48	Monitoring Plan	A summary of flux measurement procedures for the project area, with a copy of a flux

		measurement protocol used by field personnel to carry out measurements.
PDR.49	Monitoring Plan	A reference to the monitoring plan.
PDR.50	Monitoring Plan	Any methodology deviations. Such deviations must include the text that is being modified and the proposed new language.
PDR.51	Stratification	Justification for not stratifying carbon stocks.
PDR.52	Stratification for SOC	Description for how the strata were delineated.
PDR.53	Stratification for SOC	Map(s) of the initial strata boundaries.
PDR.54	Stratification for Biomass	Description for how the strata were delineated.
PDR.55	Stratification for Biomass	Map(s) of the initial strata boundaries.
PDR.56	Measuring Carbon Stocks	Proposed method for allocating plots to stratum.
PDR.57	Measuring Carbon Stocks	Description of plot sizes and layout (such as the use of nests and their sizes) for each carbon pool.
PDR.58	Soil Plot Design	Diagram of a soil plot showing the locations of artificial marker horizons and core samples within the plot over time.
PDR.59	Soil Plot Design	Description of the fixed soil sample depth.
PDR.60	Frequency of Carbon Stock Measurements	The anticipated frequency of monitoring for each plot and flux measurement location – all carbon stock plots should be measured for the first verification.
PDR.61	Monitoring Methane	The selected approach for monitoring methane.
PDR.62	Methane Models from Literature	Justification of methane flux model from the literature, per the requirements of Section 9.2.2.1.
PDR.63	Covariates for Proxy Methane Models	A list of possible covariates and the sources of data available for each.
PDR.64	Covariates for Proxy Methane Models	A list of selected covariates to be used for model fitting.
PDR.65	Stratification for Methane Emissions	Description for how the strata were delineated.
PDR.66	Stratification for Methane Emissions	Map(s) of the initial strata boundaries indicating which stratum is likely to yield the greatest methane emissions flux.
PDR.67	Stratification for Methane Emissions	Justification per the criteria in Section 9.2.2.3.1 for the stratum that is likely to yield the greatest methane emissions flux.
PDR.68	Instrumentation for Chambers	Diagram of chamber design.

PDR.69	Eddy Covariance Measurements	The type of analyzer selected for direct measurements of methane, including a description of the resolution of measurements (in ppb) and the frequency at which measurements are to be taken (in Hz).
PDR.70	Eddy Covariance Measurements	A table of meteorological variables selected for measurement. For each variable in the table, justification for its selection, the unit of measurement, resolution of measurement and frequency of measurement.
PDR.71	Eddy Covariance Measurements	A description the eddy covariance tower configuration including the distances between sensors (vertical, northward and eastward separation).
PDR.72	Eddy Covariance Measurements	A scale diagram of the eddy covariance tower configuration showing the relative location and distance of the anemometer relative to the methane sensor.
PDR.73	Eddy Covariance Measurements	Plan view diagram or map of the eddy covariance tower delineating strata and the area of highest anticipated emissions within a 100m radius of the tower. Delineation of any patch vegetation (twice the dominant canopy height and occupying >100m^2 in area) occurring within the estimated 80% footprint area.
PDR.74	Eddy Covariance Measurements	Description of dominant plant canopy height (in m) over an annual cycle. An estimate of the 80% flux footprint distance (in m) and parameter estimates, as follows: σw= standard deviation of the vertical velocity fluctuations (m/s) $u*$= surface friction velocity (m/sec) zm= measurement height (m) hm= planetary boundary layer height (m) or 1000m zm= roughness length (m) or 1/10th of the average canopy height
PDR.75	Monitoring Nitrous Oxide	The selected approach for monitoring nitrous oxide.
PDR.76	Determining Project Area Exposure to Nitrogen Loading	Location of the project area within a minimum definable watershed, using a USGS, EPA or state delineated watershed.
PDR.77	Determining Project Area Exposure to Nitrogen Loading	Locations of all NPDES major dischargers and public works projects producing > 1 MGD of elevated nitrogen effluent (>3 mg TN/L) discharging into the project area and located within the minimum definable watershed.
PDR.78	Determining Project Area Exposure to Nitrogen Loading	List of EPA CWA Section 303d designated impaired waters for the state.
PDR. 79	Default Values for Nitrous Oxide Monitoring	Justification for the selected default value.
PDR.80	Covariates for Proxy Nitrous Oxide Models	A list of possible covariates and the sources of data available for each.
PDR.81	Covariates for Proxy Nitrous Oxide Models	A list of selected covariates to be used for model fitting.

PDR.82	Model Fit for Nitrous Oxide	Justification that the proxy is an equivalent or better method (in terms of reliability, consistency or practicality) to determine the value of interest than direct measurement.
PDR.83	Stratification for Nitrous Oxide Emissions	Description for how the strata were delineated.
PDR.84	Stratification for Nitrous Oxide Emissions	Map(s) of the initial strata boundaries indicating which stratum is likely to yield the greatest nitrous oxide emissions flux.
PDR.85	Stratification for Nitrous Oxide Emissions	Justification per the criteria in Section 9.2.2.3.1 for the stratum that is likely to yield the greatest nitrous oxide emissions flux.
PDR.86	Field Training for Field Sampling	A description of the type and frequency of training of field personnel responsible for sampling carbon stocks, fluxes, and covariates.
PDR.87	Quality Control and Assurance of Eddy Covariance Data	Any methodology deviations. Such deviations must include the text that is being modified and the proposed new language.
PDR.88	Data and Parameters Available at Validation	The value of each variable, data and parameter in Appendix I.
PDR.89	Data and Parameters Available at Validation	The units, descriptions, source, purpose and comments for each variable reported in the PD.
PDR.90	Chamber Description	A description of the chamber design, with its dimensions or total volume, and cross-sectional area.
PDR.91	Chamber Description	Diagram of chamber plot randomization design and the resulting chamber locations within each stratum, with the chambers identified as replicates. Provide dates when chambers were deployed in each stratum. Provide a justification that the locations chosen are conservative (ie, that they are likely to predict methane emissions flux for the entire stratum for which they are representative.)

APPENDIX L: SUMMARY OF MONITORING REPORT REQUIREMENTS

MRR#	Category	Requirements
MRR.1	Project Activities	Plan for establishment of permanent wetland plant community after project construction. Plan must include tracking aerial extent of emergent vegetation long-term monitoring of such communities, as well as plans for continued maintenance if necessary. This documentation must demonstrate that the project activity results in the accumulation or maintenance of soil carbon stock and that, upon completion of the project activities, the project area must meet the definition of a wetland.
MRR.2	Project Activities	Evidence that the project engineering and design takes into account local water level elevation, tidal range, geotechnical characteristics, sea level rise projections, and the range of plant growth within those constraints.
MRR.3	Substrate Establishment	Post-construction report, including an as-built drawing showing plan view and cross section of the project area along with an estimate of post-construction sediment elevation relative to a geodetic or tidal datum.
MRR.4	Substrate Establishment	Aerial image of the project area within three years prior to construction and an aerial image within one year post-construction.
MRR.5	Vegetation Establishment	A description of the quantity, species, date and location of vegetation establishment, and photographs of the operation. This documentation must demonstrate that the project activity results in the accumulation or maintenance of soil carbon stock.
MRR.6	Vegetation Establishment	Aerial image of the project area indicating where species were established.
MRR.7	Temporal Project Boundaries	The project start date.
MRR.8	Temporal Project Boundaries	The project crediting period start date and length.
MRR.9	Temporal Project Boundaries	Evidence of the start of monitoring per the frequency requirements described in Sections 5.4, 9.2.1.1, 9.2.2.4, and 9.2.3.4.
MRR.10	Grouped Projects	A list and description of all project activity instances in the group, including project activity instance start dates.
MRR.11	Grouped Projects	A map of the boundaries of all project activity instances in the group demonstrating that all instances are in the designated geographic region.
MRR.12	Baseline Emissions	Calculations of current baseline emissions $\mathrm{EB}\ \Delta\mathrm{m}$ as of the monitoring period.
MRR.13	Baseline Emissions	Calculations of baseline emissions $\mathrm{EB}\ \Delta\mathrm{m}-1$ from prior monitoring periods.

MRR.14	Emissions Coefficients	Source and date of the emission coefficient.
MRR.15	Emissions Coefficients	Reference to the exact page number or worksheet cell in the source.
MRR.16	Project Emissions or Emissions Reductions and/or Removals	Calculations of current project emissions or emissions reductions and/or removals $\mathrm{EP}\ \Delta\mathrm{m}$ as of the monitoring period.
MRR.17	Project Emissions or Emissions Reductions and/or Removals	Calculations of project emissions or emissions reductions and/or removals $\mathrm{EP}\ \Delta\mathrm{m}-1$ from prior monitoring periods.
MRR.18	Emissions or Emissions Reductions and/or Removals Events in Project Area	The selected definition of a significant disturbance.
MRR.19	Emissions or Emissions Reductions and/or Removals Events in Project Area	A map of the boundaries of any significant disturbance in the project area during the monitoring period.
MRR.20	Emissions or Emissions Reductions and/or Removals Events in Project Area	Evidence that plots were installed into these disturbed areas and were measured per Section 9.2.1.
MRR.21	Hydrologic Effects	Documentation that the project will not have a significant negative impact on hydrologically connected areas. This may include a Clean Water Act permit issued by the USACE, NEPA decision (ROD or FONSI) issued by the appropriate lead federal agency, or compliance documentation from local floodplain management agencies.
MRR.22	Quantification of GERs	Quantified GERs for the monitoring period including references to calculations.
MRR.23	Quantification of GERs	Quantified GERs for the prior monitoring period.
MRR.24	Quantification of GERs	A graph of GERs by monitoring period for all monitoring periods to date.
MRR.25	Quantification of NERs	Quantified NERs for the monitoring period including references to calculations.
MRR.26	Quantification of NERs	Quantified NERs for the prior monitoring period.
MRR.27	Quantification of NERs	A graph of NERs by monitoring period for all monitoring periods to date.
MRR.28	Confidence Deduction	The calculated confidence deduction and supporting calculations.
MRR.29	Confidence Deduction	Any methodology deviations. Such deviations must include the text that is being modified and the proposed new language.

MRR.30	AFOLU Pooled Buffer Account	Reference to the VCS requirements used to determine the AFOLU pooled buffer account allocation.
MRR.31	AFOLU Pooled Buffer Account	Reference to calculations used to determine the AFOLU pooled buffer account allocation.
MRR.32	Buffer Release	Reference to the VCS requirements used to determine the release from the AFOLU pooled buffer account.
MRR.33	Buffer Release	Reference to calculations used to determine the buffer release.
MRR.34	Vintages	Quantified NERs by vintage year for the monitoring period including references to calculations.
MRR.35	Project Performance	Comparison of NERs presented for verification relative to those from *ex-ante* estimates.
MRR.36	Project Performance	Description of the cause and effect of differences from *ex-ante* estimates.
MRR.37	Monitoring Plan	Documentation of training for field measurement crews.
MRR.38	Monitoring Plan	Documentation of data quality assessment.
MRR.39	Monitoring Plan	References to plot allocation for carbon stock measurement.
MRR.40	Monitoring Plan	List of plot GPS coordinates for plots and flux measurement devices.
MRR.41	Monitoring Plan	Description and diagram of flux measurements devices for methane and/or nitrous oxide.
MRR.42	Monitoring Plan	The estimated carbon stock, standard error of the total for each stock, and the sample size for each stratum in the project area.
MRR.43	Monitoring Plan	Any methodology deviations. Such deviations must include the text that is being modified and the proposed new language.
MRR.44	Monitoring Plan	Frequency of monitoring for each plot and flux measurement location – all carbon stock plots should be measured for the first verification.
MRR.45	Stratification for SOC	Map(s) of the current strata boundaries.
MRR.46	Stratification for SOC	A description of changes to the strata boundaries (if applicable).
MRR.47	Stratification for Biomass	Map(s) of the current strata boundaries.
MRR.48	Stratification for Biomass	A description of changes to the strata boundaries (if applicable)
MRR.49	Measuring Carbon Stocks	Method for allocating plots to stratum.
MRR.50	Measuring Carbon Stocks	Map of the location of plots within strata.
MRR.51	Measuring Carbon Stocks	Description of plot sizes and layout (such as the use of nests and their sizes) for each carbon pool.

MRR.52	Soil Plot Design	For each measured soil plot, a diagram showing the location of installed artificial marker horizons and sampled cores.
MRR.53	Soil Plot Design	Field report describing soil sample depths (accretion depth and fixed soil sample depth) and coring devices used to collect samples. The report must also include number of soil samples and their identification in a chain of custody form submitted to the laboratory.
MRR.54	Frequency of Carbon Stock Measurements	List of plots measured during the monitoring period – all carbon stock plots should be measured for the first verification.
MRR.55	Methane Models from Literature	Demonstration that the selected model is applicable to the project area per the requirements of Section 9.2.2.1.
MRR.56	Methane Models from Literature	Description of how model predictions are converted to tCO_2e/day.
MRR.57	Data Collection for Proxy Methane Model	Complete references to the source of any data collected from literature or reports.
MRR.58	Data Collection for Proxy Methane Model	Data collection procedures, plans or protocols for any data collected directly from the project area.
MRR.59	Model Fit for Methane	The form of the selected model.
MRR.60	Model Fit for Methane	Summary statistics of the model fit as appropriate to the fitting of the model.
MRR.61	Model Fit for Methane	The estimated model parameters.
MRR.62	Model Fit for Methane	A description of the range of covariate data with which the model was fit.
MRR.63	Model Prediction for Methane	The values of any measured covariates.
MRR.64	Model Prediction for Methane	The predicted methane flux.
MRR.65	Processed Chamber and Eddy Covariance Flux Data	A table of chamber flux or eddy covariance emission summary statistics of the mean (±1SEM) and number of samples for each mean in tCO_2e/ac/day for each sample location within a stratum.
MRR.66	Stratification for Methane Emissions	Map(s) of the current strata boundaries.
MRR.67	Stratification for Methane Emissions	A description of changes to the strata boundaries (if applicable).
MRR.68	Instrumentation for Chambers	Diagram of chamber design.

MRR.69	Instrumentation for Chambers	Map showing the location of chambers in the project area.
MRR.70	Instrumentation for Eddy Covariance	Diagram or map of eddy covariance tower delineating the selected footprint area where flux was integrated from and the computed mean 80% footprint distance (including the footprint model used) from the tower during the period of analysis. A table of computed estimates for each of the following parameters: σ_w = standard deviation of the vertical velocity fluctuations (m/s) u^*= surface friction velocity (m/sec) z_m= measurement height (m) z_0= roughness length (m) (or canopy height and density to be used to estimate roughness length)
MRR.71	Instrumentation for Eddy Covariance	Description of the published model used to define the footprint.
MRR.72	Instrumentation for Eddy Covariance	Map showing the location of eddy covariance towers in the project area.
MRR.73	Instrumentation for Eddy Covariance	Documentation of adherence to manufacturer-recommended procedures for calibration of the methane analyzer.
MRR.74	Eddy Covariance Data Processing and Flux Computation	Frequency diagram of wind direction (0-359° with 30° intervals) and velocity (m/s) for the period of analysis.
MRR.75	Eddy Covariance Data Processing and Flux Computation	Summary of the dates of data collection, the selected approach for averaging over each period, explicit formulas used for computing flux, number of 0.5-hr samples used in calculations.
MRR.76	Eddy Covariance Data Processing and Flux Computation	Graphical plot of 0.5-hr GHG concentration (ppmv), wind velocity and direction, and temperature used for the flux calculations
MRR.77	Eddy Covariance Data Processing and Flux Computation	Summary statistics (number of samples, mean, median, variance) of GHG flux for each averaging period.
MRR.78	Chamber Sampling for Methane	Table of sampling event dates for the monitoring period, including the time of day samples were collected, water level relative to the soil surface, soil temperature, and air temperature.
MRR.79	Chamber Sampling for Methane	Copy of field data sheets documenting time intervals when samples were collected, sample identification number, and verification of the total number of samples received by the laboratory.
MRR.80	Eddy Covariance Measurement	A table of meteorological variables selected for measurement. For each variable in the table, an indication of whether the variable was measured, the make and model of the instrument used for measurement.
MRR.81	Eddy Covariance Measurement	For each measured variable, a graphical plot or table of the data with respect to time during the monitoring period. A data table or plot must include at minimum: air temperature, methane concentration, methane flux. A list of interpolated/missing samples.

MRR.82	Eddy Covariance Measurement	Documentation of calibration dates and zero checks for methane analyzer. Provide the date of last full calibration (0-10 ppm methane standard). Provide dates of carbon-free air gas checks for methane analyzer.
MRR.83	Data Collection for Proxy Nitrous Oxide Model	Complete references to the source of any data collected from literature or reports.
MRR.84	Data Collection for Proxy Nitrous Oxide Model	Data collection procedures, plans or protocols for any data collected directly from the project area.
MRR.85	Model Fit for Nitrous Oxide	The form of the selected model.
MRR.86	Model Fit for Nitrous Oxide	Summary statistics of the model fit as appropriate to the fitting of the model.
MRR.87	Model Fit for Nitrous Oxide	The estimated model parameters.
MRR.88	Model Fit for Nitrous Oxide Covariance Data	A description of the range of covariate data with which the model was fit.
MRR.89	Model Prediction for Nitrous Oxide	The values of any measured covariates.
MRR.90	Model Prediction for Nitrous Oxide	The predicted nitrous oxide flux.
MRR.91	Stratification for Nitrous Oxide Emissions	Map(s) of the current strata boundaries.
MRR.92	Stratification for Nitrous Oxide Emissions	A description of changes to the strata boundaries (if applicable).
MRR.93	Chamber Sampling for Nitrous Oxide	Table of sampling event dates for the monitoring period, including the time of day samples were collected, water level relative to the soil surface, soil temperature, and air temperature.
MRR.94	Chamber Sampling for Nitrous Oxide	Copy of field data sheets documenting time intervals when samples were collected, sample identification number, and verification of the total number of samples received by the laboratory.
MRR.95	Energy Consumption Measurement Method	The selected approach to monitoring energy consumption.
MRR.96	Direct Measurement of Energy Consumption	Energy consumption for each energy type listed in Section 8.1.1.
MRR.97	Direct Measurement of Energy Consumption	References to records of energy consumption.
MRR.98	Cost Approach to Energy	Justification for the proportion of dredging budget allocated for fuel (or electricity) purchases.

	Consumption	
MRR.99	Cost Approach to Energy Consumption	Justification for choice of energy type(s).
MRR.100	Cost Approach to Energy Consumption	Documentation of historic energy costs at the time of dredging activities.
MRR.101	Cost Approach to Energy Consumption	Justification of estimate of energy consumption.
MRR. 102	Monitoring Sediment Transport	Justification for the estimate of volume of dredged sediment transported.
MRR. 103	Monitoring Sediment Transport	Justification for the estimate of the density of dredged sediment.
MRR.104	Monitoring Sediment Transport	Estimated mass of sediment transported.
MRR.105	Monitoring Allochthonous Carbon	Reference(s) to the regionally appropriate literature used to determine the correct factor for mineral-associated carbon.
MRR.106	Field Training for Field Sampling	The type and frequency of training of field personnel during the monitoring period.
MRR.107	Carbon Stock Measurements	Biomass and SOC carbon stock data for all plots, along with any ancillary spreadsheets or computer code used to generate these predictions.
MRR.108	Carbon Stock Measurements	List of outliers with unusually high or low biomass or SOC, including justification for their continued inclusion.
MRR.109	Carbon Stock Measurements	Results of accuracy assessment if non-destructive sampling techniques are used. Otherwise, justification for why accuracy need not be formally addressed.
MRR.110	Quality Control and Assurance of Eddy Covariance Data	Description of processing software used, assumptions, and data quality control measures, which must include the selected method of coordinate rotation, detrending, and density fluctuation correction.
MRR.111	Laboratory Analyses	Documentation of the laboratory QA/QC protocols, the methods of sample analysis, and general calibration procedures used the laboratories conducting the analysis.
MRR.112	Data and Parameters Monitored	The value of each variable, data and parameter in Section 9.4.
MRR.113	Data and Parameters Monitored	The units, descriptions, source, purpose, references to calculations and comments for each variable reported in the Monitoring Report.
MRR.114	Data and Parameters Monitored	For those variables obtained from direct measurement, a description of measurement methods and procedures. These may simply be references to components of the monitoring plan.

MRR.115	Data and Parameters Monitored	For those variables obtained from direct measurement, a description of monitoring equipment including type, accuracy class and serial number (if applicable). These may simply be references to components of the monitoring plan.
MRR.116	Data and Parameters Monitored	Procedures for quality assurance and control, including calibration of equipment (if applicable).
MRR.117	Monitoring Grouped Projects	List and descriptions of all project activity instances in the group.
MRR.118	Monitoring Grouped Projects	Project activity instance start dates.
MRR.119	Monitoring Grouped Projects	Map indicating locations of project activity instances added to the group.
MRR.120	Monitoring Grouped Projects	List of additional stratifications used for additional project activity instances; justification for why flux measurements are still located in the most conservative stratum (9.2.2, 9.2.3).
MRR.121	Monitoring Grouped Projects	As project activity instances are added, monitoring plan must be updated to reflect additional monitoring times and plot locations.

APPENDIX M: SOURCE OF EMISSIONS FACTORS FOR ENERGY CONSUMPTION

		CO2		CH4		N20				
Fuel Type	Proponent reports as:	Emissions (kg/MMBtu)	tCO2 / MMBtu	Emissions (kg/MMBtu)	tCO2e / MMBtu	Emissions (kg/MMBtu)	tCO2e / MMBtu	Total Emissions (tCO2e/MMBtu)	Energy Content (MMBtu/unit)	**Emission Coefficient**
Diesel	gal	73.96	0.07396	0.003	0.000063	0.0006	0.000186	0.07421	0.138	**0.010241**
Gasoline	gal	70.22	0.07022	0.003	0.000063	0.0006	0.000186	0.07047	0.125	**0.008809**
Biodiesel	gal	73.84	0.07384	0.0011	0.0000231	0.00011	0.0000341	0.07390	0.128	**0.009459**
CNG	scf	53.02	0.05302	0.001	0.000021	0.0001	0.000031	0.05307	0.001028	**0.000055**
Electricity	kWh	see eGRID regional emissions factor								

Sources:

- Emissions factors and energy content for fuels: EPA Final Mandatory Reporting of Greenhouse Gases Rule Table C-1, C-2 (http://www.epa.gov/ghgreporting/documents/pdf/2009/GHG-MRR-FinalRule.pdf). Emissions in kg/MMBtu are taken directly from the EPA Mandatory reporting Rule. Emissions in tCO2e/MMBtu apply a unit conversion to tons (1 ton = 1,000 kg) and multiply by the appropriate global warming potential (1 for CO_2, 21 for CH_4, 310 for N_2O – the project proponent must confirm the global warming potentials per the current version of VCS Standard). Total emissions are a simple sum of the emissions in tCO2e/MMBtu of each of the three covered gases. The emission coefficient is calculated as the product of the total emissions and the energy content of the fuel type.
  For updates to these factors, refer to the EPA website (http://www.epa.gov/ghgreporting/reporters/subpart/c.html) or the federal regulations (40 C.F.R. § 98, Subpart C, Tables C-1 and C-2).
- eGRID regional emissions factors for electricity: http://www.epa.gov/cleanenergy/documents/egridzips/eGRID2012V1_0_year09_GHGOutputrates.pdf ('annual total output emission rates'). Note the unit conversions required to calculate the emissions from electricity usage in terms of tCO_2e, given that eGRID factors are stated in terms of lb/MWh and lb/GWh, and in terms of CH_4 and N_2O emissions (vs. CO_2e).
  For the current version of emissions factors, refer to http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html. Locate the eGRID GHG output summary file for the correct emission year (eg, eGRID2012 provides actual generation data from 2009). Because there is typically a lag of several years, if data for the current year or recent years are not available, use the most recent data (eg, if eGRID2012 is the most recent data available in 2013, then eGRID2012 with 2009 data should be used for all years 2009-2013). In the GHG summary file, use data for the appropriate eGRID subregion for 'annual total output emission rates.'

DOCUMENT HISTORY

Version	Date	Comment
v1.0	30 Jan 2014	Initial version released

CAPCOA GHG Rx Protocol:

Methodology for Compost Additions to Grazed Grasslands

(Based on the American Carbon Registry™ protocol, Version 1.0, October 2014)

Approved by the CAPCOA Board December 10, 2014*

* The optional composting facility component of the protocol was approved by the CAPCOA Board on February 8, 2017

The following conditions apply for use in the CAPCOA GHG Rx:

1. **Approve protocol only for projects that occur within California.**

2. **Approve protocol only for projects that occur after January 1, 2007.**

3. **Include a requirement for a contract between the project proponent and the lead agency to ensure enforceability.**

4. **On February 8, 2017, the CAPCOA Board approved the Optional Composting Facility component of the protocol. The following conditions apply for use of this part of the protocol in the CAPCOA GHG Rx:**
    a. **Only GHG emission reductions that occurred in California are eligible for listing in the CAPCOA GHG Rx.**
    b. **Only those GHG reductions that occurred after January 1, 2007 are eligible for listing in the CAPCOA GHG Rx (or January 1, 2005 for reductions covered by San Joaquin Valley APCD Rule 2301).**
    c. **A California air district issued permit, a local jurisdiction's conditions of approval, or a contract between the project proponent and the lead agency is required which shall include the following conditions:**
        a. **GHG credits shall only be approved under this protocol for waste diversion in excess of what is already required under existing regulations, including, but not limited to: AB939 (Sher, 1989) and local agency regulations/ordinances.**
        b. **GHG credits shall only be approved under this protocol for composting operations not subject to the requirements of a District rule (i.e., New Source Review or prohibitory rules) regarding control of VOCs from composting operations. Many of the same techniques that are required to reduce VOCs will also reduce methane emissions. Therefore, the methane reduction resulting from the control of VOCs should not be considered surplus.**
        c. **GHG credits shall only be approved under this protocol for cases where the eligible waste is diverted from an uncontrolled landfill or an uncontrolled wastewater treatment plant. A controlled landfill already reduces VOC emissions substantially. Diverting waste to composting operations will result in an increase in VOC emissions. The American Carbon Registry (ACR) protocol specifically prohibits claiming GHG credits in instances where the facility (e.g., landfill or wastewater treatment plant) from which source material was diverted already captures methane.**
        d. **To minimize VOC emissions, the owner/operator of the composting operation shall capture and control VOC emissions by at least 72% by weight during the active composting phase. VOC controls are not required during the curing phase.**

   i. **Typical methods to capture and control VOC emissions from composting operations include, but are not limited to:**
      1. **Compost Covered Positive Aerated Static Pile.**
      2. **Negative Aerated Static Pile vented to a Biofilter.**
   ii. **The ACR protocol requires the waste material used for compost production that contains food waste or manure to be either (1) mixed and incorporated into the composting process within 24 hours of delivery of the waste to the composting facility, (2) covered or blended with a layer of high-carbon materials such as wood chips or finished compost within 24 hours of delivery, and mixed and incorporated into the composting process no more than 72 hours after delivery, (3) placed in a controlled environment within 24 hours of delivery, or (4) handled using any other alternative Best Management Practices to avoid anaerobic decomposition after delivery and before incorporation into the composting process of the source material.**

e. **To minimize PM^{10} emissions, the owner/operator of the composting operation shall not use the open turned windrow compost method. The owner/operator of the composting operation shall use dust suppressants and/or water sprays to control vehicle traffic PM^{10} emissions from unpaved roads, good housekeeping measures to control PM^{10} emissions from paved roads, and water sprays on all material handling operations.**

The American Carbon Registry™

Methodology for Compost Additions to Grazed Grasslands

Version 1.0

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A. Methodology Description

A.1 Acronyms

ACR	American Carbon Registry
CDM	Clean Development Mechanism
CH_4	Methane
CO_2	Carbon Dioxide
EPA	Environmental Protection Agency
ERT	Emission Reduction Ton
GHG	Greenhouse Gas
N_2O	Nitrous Oxide
NRCS	Natural Resources Conservation Service
PBM	Process-based Biogeochemical Model
SOC	Soil Organic Carbon
VCS	Verified Carbon Standard
VVB	Validation and Verification Body

A.2 Background

Grazed grasslands are defined by the Natural Resource Conservation Service (NRCS) of the United States Department of Agriculture (USDA) as "land on which the vegetation is dominated by grasses, grass-like plants, shrubs and forbs." This definition includes land that contains forbs, shrubland, improved pastureland, and improved rangeland for which grazing is the predominant use (NRCS 2009). Adding compost to Grazed Grasslands can be an effective way to increase soil carbon sequestration and avoid emissions related to the anaerobic decomposition of organic waste material in landfills. In addition to climate benefits, adding compost stimulates forage growth and can improve the quality of soils. This document contains a methodology to account for the carbon sequestration and avoided GHG emissions related to compost additions to Grazed Grasslands, following specifications by the American Carbon Registry (ACR). The current version of this methodology includes only one project activity – compost addition to Grazed Grasslands. Additional project practices and additional organic soil amendment types may be added in future revisions. This approach will allow the experience gained from the first projects to be incorporated in future versions of the methodology.

Grassland soils are an important sink for carbon, accounting for approximately 20 % of the world's soil carbon stocks (FAOSTAT 2009; Conant 2010). The amount of carbon stored in grassland soils is largely driven by environmental conditions such as temperature, rainfall, and soil characteristics, as well as the productivity of various grassland plant communities (Derner and Schuman 2007). These factors are subject to temporal variability both within seasons and across multiple years (Svejcar et al. 2008; Ingrahm et al. 2008). Many grasslands in the US have been degraded through overgrazing which in some cases can lead to declines in soil organic matter (Conant and Paustian 2002). However, research also suggests that with improved management grassland soils can also offer considerable potential to aid greenhouse mitigation efforts through additional soil carbon sequestration (Lal 2002; Conant and Paustian 2002; Derner and Schuman 2007).

One management strategy that may hold promise for enhancing carbon sequestration in grasslands is the application of organic soil amendments such as compost or composted biosolids. A growing body of research indicates that the application of these organic materials can often have positive impacts on the amount of carbon stored in both grassland (Walter et al. 2006; Ippolito et al. 2010; Kowaljow et al. 2010; Ryals et al. 2014) and cropland soils (Canali et al. 2004; Celic et al. 2004; Montovi et al. 2005; Cai and Qin 2006). The buildup of soil carbon occurs via two mechanisms; 1) directly from carbon contained in the compost, and 2) indirectly through enhanced plant growth and subsequent deposition of plant biomass (Walton et al. 2001; Walter et al. 2006; Ryals and Silver 2013). The recent model work of Zhai et al. 2014 demonstrates gains in soil organic carbon due to application of biosolids for 10 years, with further SOC gains over the next 10 or more years due to biomass and/or carbon sequestration.

A number of peer-reviewed studies involving the application of compost or composted biosolids to temperate grasslands have been carried out over both short-term (0-5 yrs) and long-term (5-14 yrs) experimental periods. At two Mediterranean grassland sites in California, Ryals et al. (2014) measured C sequestration years after a single compost addition. Compost amendment resulted in a significant increase in bulk soil organic C content at a Central Valley site, and a similar but non-significant trend at a Coast Range site. Compost additions also significantly increased plant growth as measured by net primary productivity at both the Central Valley and Coast Range sites (Ryals and Silver 2013). Likewise, in a three year study conducted at a semi-arid steppe site in northwest Patagonia, the application of composted biosolids (40 t ha-1) also increased plant growth and soil organic matter relative to an untreated control (Kowaljow et al. 2010). More importantly, several long-term grassland experiments have also found that the effect of compost application on plant growth and soil C can persist for more than a decade (Sullivan et al. 2006; Ippolito et al. 2010; Walton et al. 2001). For instance, at a semi-arid grassland site in Colorado differences in plant growth (Sullivan et al. 2006) and total soil C (Ippolito et al. 2010) were still detectable 14 years after applying compost at 6 different rates (0, 2.5, 5, 10, 21, and 30 t ha-1). Similarly Walton et al. (2001) found that 32% of applied biosolids remained as particles greater than 2mm 18 years after application to an arid rangeland site in New Mexico. The above-mentioned studies and others in the broader peer-reviewed literature provide evidence that compost application to grasslands can facilitate long-term soil C sequestration and improved plant growth, and thus form the scientific basis for the current methodology.

A.3 Summary Description of the Methodology

Compost additions to Grazed Grasslands can generate Emission Reduction Tons (ERTs) from avoided Greenhouse Gas (GHG) emissions and removals resulting from three processes:

1) **Avoidance of anaerobic decomposition (Optional)** of the organic material used in compost production. Methane (CH_4) emissions that result from anaerobic decomposition of the organic material used in the production of compost under baseline conditions – for example, when the organic matter is buried in landfills – can be avoided by composting[1] and applying compost on Grazed Grasslands. It is not required in this methodology to include the avoided emissions from preventing the anaerobic decomposition of the organic material used in the production of compost. However, if these avoided emissions are included, evidence must be provided that (1) the avoided emissions have not been claimed under a different Carbon Credit program, such as the Climate Action Reserve's composting methodology, and that (2) the baseline fate of the organic matter can be demonstrated following the procedures included in Section C of this methodology.
2) **Direct increase in soil organic carbon (SOC) content (Required)** through adding a carbon source from compost. The carbon (C) content of applied compost will lead to a direct increase in soil organic carbon (SOC) content of the Grazed Grasslands where the compost is applied. Even though the carbon added through compost additions will gradually decompose over time, a significant portion will end up in stable carbon pools. The portion of the compost carbon that will remain in the stable pools is likely to be greater than the portion that would be stabilized under baseline conditions. Only the stable carbon pools that are predicted to remain after 40 years after compost addition can be counted. These stable soil C pools are conceptually equivalent to the "intermediate" and "passive" C pools defined in recent literature reviews by Trumbore (1997) and Adams *et al.* (2011). This 40 year period is also similar in duration to the 40 year minimum project term used in the approved ACR Forest Carbon Project protocol (ACR 2010). As such, the minimum project period for this protocol is 40 years.
3) **Indirect increase in SOC sequestration (Required)** through enhanced plant growth in Grazed Grasslands amended with compost. The N and P content of the compost, as well as the improved soil water holding capacity of soils amended with compost, may in some cases lead to an indirect increase in SOC content through an increase in net primary productivity (NPP). The impact of compost on SOC content will depend on the compost's nutrient content and availability, the soil properties, and grazing management strategies.

This methodology requires the use of a model to predict direct and indirect changes in SOC under the baseline and project scenarios. This methodology does not prescribe a specific model. The model can be either a process-based biogeochemical model (PBM) such as the DAYCENT or Denitrification-Decomposition (DNDC) models, or an empirical model such as a Tier-2 Empirical Model that is shown to

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[1] Whereas composting is mostly an aerobic process that occurs in presence of oxygen, composting may still release a small amount of methane.

be effective for the conditions of the Project Parcels (see Section D.1). It is up to the project proponents to demonstrate that the model is sufficiently accurate for the Project Parcels (see section D.1 for model requirements). Under the baseline scenario, the model is used to simulate any on-going changes to SOC, including potential continuing loss of SOC. Under the project scenario, the model is used to simulate the amount of compost carbon that is stored in recalcitrant SOC pools, and any indirect changes in SOC due to an increase in net primary production and under specific grazing management strategies. Even though empirical models and PBMs have been shown to be highly valid across a wide range of management practices and geographic areas, soil samples and field measurements are required to validate the models for use in specific Project Parcels. As a consequence, this methodology requires monitoring by periodic (10 year) analyses of soil samples for model validation at different times throughout the project's lifetime.

Adding compost to Grazed Grasslands has the potential to increase GHG emissions from secondary sources. Specifically, N_2O emissions from soils are produced due to nitrification and de-nitrification of the available N added through the compost addition (Box 1). These processes further require a carbon source, which is readily available after compost addition. Indirect emissions from nitrate leaching may also occur but GHG emissions resulting from the leached nitrate are expected to be insignificant, at the rate compost is applied in projects under this methodology based on findings reported by DeLonge et al. (2013) for California grasslands. In addition to soil N_2O emissions (from de-nitrification), all emissions from fuel that was used to create, transport, or apply the compost is included in the quantification procedure. Under this methodology, soil N_2O emissions are quantified using an applicable Tier-2 Empirical Model, or a calibrated PBM. The GHG emissions from increased fuel use must be quantified using standard emission factors. Likewise, enteric emissions from increases in stocking must be quantified with the ACR Grazing Land and Livestock Management MICROSCALE Tool for Tier I estimation of emissions from enteric methane.

Apart from the economic benefit of increased forage production, applying compost to Grazed Grasslands also has many environmental co-benefits, such as improved soil quality and increased nutrient and water availability for vegetation due to improved soil water holding capacity, which increases resilience to more intense precipitation events, slows the onset of drought, and confers additional ecosystem services. Compost application may also reduce erosion in certain contexts due to improvements in vegetation cover. Compost can be added to most existing Grazed Grasslands.

Box 1. Further background on N_2O fluxes after compost application

The magnitude of the N_2O fluxes after compost addition may be highly variable and difficult to predict. For example, in an experiment where N_2O fluxes were measured after a one-time compost addition on two sites in California, no significant increases in N_2O fluxes were observed (Ryals and Silver 2012). In laboratory incubations under controlled conditions, however, a pulse of N_2O emissions was detected in soils after compost addition that was significantly greater than soils to which no compost was added. However, the pulse was short-lived (four days), and represented only a very small component of the net soil GHG emissions (expressed as CO_2-equivalents) released from the controlled wet up event (Ryals and

Silver 2012). Such conditions represent ideal conditions for N_2O release and are unlikely to be present for a long period of time in the field. High-nitrogen organic materials such as manure or processed manure additions may be more prone to N_2O emissions. Due to the difficulty in predicting N_2O emissions, this methodology allows some flexibility in the approach to quantify N_2O.

Production of N_2O is generally greatest under warm and humid conditions and where soil nitrogen concentrations are highest. Therefore, the timing of compost application relative to weather conditions and plant demand is crucial to minimize N_2O emissions. If the Grazed Grassland is dominated by annual plants and the compost application occurs before plant establishment, a significant amount of inorganic N may remain in the soil, resulting in significant N_2O fluxes. However, in a Mediterranean climate, there is an ideal window for applying compost. Specifically, fall applications are preferred, ideally shortly before first rains and prior to plant establishment in annual-dominated grasslands. Once the soil gets wet, compost applications may become more logistically challenging due to restricted access to the field as well as less beneficial, while initial growth of annuals in response to early rains can be expected to help limit inorganic N losses from the soil. The ideal window for compost addition may be different for other climates. In this protocol we require following the advice from a Qualified Expert (i.e., a Certified Rangeland Manager, NRCS Soil Conservationist or Qualified Extension Agent) as to when to apply compost.

A.4 Definitions

If not explicitly defined here, the current definitions in the latest version of the American Carbon Registry Standard apply.

Compost	The end product of a process of controlled aerobic decomposition of organic materials, consistent with California Department of Resources Recycling and Recovery (CalRecycle) standards (http://www.calrecycle.ca.gov/Laws/Regulations/Title14/ch31.htm).
Grassland	We follow the terminology of Allen et al. (2011), who indicate that the term grassland bridges pastureland and rangeland and may be either a natural or an imposed ecosystem. Grassland has evolved to imply a broad interpretation for lands committed to a forage use.
Grazed Grassland	Grassland on which annual grazing by livestock (including cattle, horses, sheep and goats) is the primary means of forage/biomass removal. In this protocol, if any grazing takes place on a yearly basis under historical baseline management the parcel may be considered "grazed" (see section E.1).
Native Grassland	A grassland where native plant species comprise greater than 10 percent of the

	total relative cover (Stromberg et al. 2007).
Process-based Biogeochemical Model	Computer model that is able to simulate biogeochemical processes and predict GHG fluxes, nutrient contents and/or water contents.
Project	The activities undertaken on a Project Parcel to generate GHG emission reductions.
Project Parcel	Individual contiguous parcel unit of grassland under control of the same entity/entities.
Qualified Expert	A Qualified Expert can be a Certified Rangeland Manager, NRCS Soil Conservationist or Qualified Extension Agent. A Qualified Expert is a professional certified to provide consulting services on all activities devoted to rangeland resources. These services include, but are not limited to, making management recommendations, developing conservation plans and management plans, monitoring, and other activities associated with professional rangeland management.
Stocking Rate	The amount of land allocated to each livestock unit for the grazing period of each year, or alternatively, the number of livestock units per hectare for the grazing period. Stocking Rate must include the number of livestock units (LU)[2], land area per LU, and the amount of time a given number of LUs occupy a given unit of land. In case rotational grazing is employed, the Stocking Rate shall include specifics on the rotational grazing management, including such factors as species, numbers, length of stay, length of rest between grazing periods, frequency of return per annum or season, season(s) of use, etc.
Tier-2 Empirical Model	Empirical model such as a linear regression model calibrated for a specific region. In the context of this methodology, a Tier-2 Empirical Model predicts SOC content or N_2O emissions as a function of one or more driving variables, such as compost carbon added, nitrogen added, clay content, annual rainfall, etc.
Waste Material	The original material that was Composted.

[2] Livestock units (also known as animal units) are a standardized measure used by the UN Food and Agriculture Organization to quantify Stocking Rates for multiple animal types and growth stages based on an estimate of the metabolic weight of the animals. A livestock unit is measured as livestock unit/time/hectare. More information on the quantification of livestock units for grazing systems in North America can be found at: http://www.lrrd.org/lrrd18/8/chil18117.htm

A.5 Applicability Conditions

In addition to satisfying the latest ACR program requirements, project activities must satisfy the following conditions for this methodology to apply:

- The Project includes one or more Project Parcels that are Grazed Grasslands at the start of the Project and remain Grazed Grasslands for the duration of the Project (Box 2).
- The annual, minimum and maximum Stocking Rate shall be determined via consultation with a Qualified Expert (see definitions – a Certified Rangeland Manager, NRCS Soil Conservationist or Qualified Extension Agent) and duly justified by the Project Proponent. Justification for the annual Stocking Rate should include a calculation of the historical Stocking Rate averaged over a 5 year period prior to the start of the Project, and an assessment of whether or not the forage productivity and quality of the parcel can sustainably support the historical Stocking Rate. In some cases the conditions of the parcel will justify using the historical Stocking Rate as the annual, while in other cases the Qualified Expert may set an annual Stocking Rate that differs from the historical Stocking Rate. Validation of the GHG project plan will include a review of the criteria used by the Qualified Expert to ensure annual Stocking Rates during the Project lifetime are sustainable, and will not lead to erosion or negatively affect species composition; subsequent verifications will review changes to the annual Stocking Rate and ensure that a Qualified Expert was properly consulted. The maximum Stocking Rate shall be set so that rangeland utilization remains sustainable, taking into account an increase in forage production and any changes in the percentage of grazer feed coming from purchased sources after the start of the crediting period.[3] The minimum Stocking Rate shall be set to ensure that plant community species composition does not change toward a less desirable plant community in response to soil quality changes following compost application.
- Any soils that are regularly flooded (i.e. more than two months per year), shall be excluded from the Project Parcels.[4] At the start of the Project the Qualified Expert must identify any land within the parcel that ought to be excluded due to a high likelihood of annual flooding. These areas can be detected by observing the topographic position in the landscape, as well as clear shifts in vegetation and soil redox features (e.g. gleying). These areas must be excluded from the Project Parcel at the beginning of the crediting period. Additionally, and in consultation with a Qualified Expert, compost application should occur in accordance with local and/or state regulations regarding application and water quality concerns. In order to prevent any unintended negative impact on forage growth, compost should not be more than ½ inch in depth at any part of the application area.
- The compost added to the Project Parcel must be within the following specifications:

[3] This approach is fully compatible with a rotational grazing strategy.

[4] The no-flood requirement is added to prevent the inclusion of land areas where a significant amount of CH_4 is likely to be emitted from soils in the project area; the accounting for methanogenesis is not included.

- The final end product after composting must have a nitrogen concentration of less than 3%[5] on a dry-weight basis.
- Best Management Practices put forward by state agencies have been followed in making the compost free of any seeds or propagules capable of germination or growth.
- The heavy metal and contaminant content of composts shall not exceed limits of the US EPA under 40 CFR 503.[6]
- The compost must be produced in accordance with Chapter 5 of EPA Part 503 Biosolids Rule process to further reduce pathogens (PFRP) and other contaminants.[7]
- Waste Material containing food waste or manure must be either (1) mixed and incorporated into the composting process within 24 hours of delivery of the waste to the composting facility, (2) covered or blended with a layer of high-carbon materials such as wood chips or finished compost within 24 hours of delivery, and mixed and incorporated into the composting process no more than 72 hours after delivery, (3) placed in a controlled environment within 24 hours of delivery, or (4) handled using any other alternative Best Management Practices to avoid anaerobic decomposition after delivery and before incorporation into the composting process of the source material.[8]
  Compost material that was produced consistently with the standards put forward by the California Department of Resources Recycling and Recovery is automatically approved.

Box 2. Further background on species composition changes and minimum grazing requirements

Compost applications may lead to changes in the plant community (either positive or negative) due to impacts of compost on nutrient concentrations and hydrology of treated soils (Bremer, 2009). The protocol does not support application of compost to intact, healthy native plant communities. Whether a grassland constitutes a healthy native plant community is best determined in consultation with a

[5] This would prevent materials that more closely resemble synthetic fertilizers from being used as an amendment.

[6] Because compost may contain trace levels of heavy metals, limits on the heavy metal contents in fertilizers, organic amendments, and biosolids are regulated through US EPA, 40 CFR Part 503. Under EPA regulations, managers must maintain records on the cumulative loading of trace elements only when bulk biosolids do not meet EPA Exceptional Quality Standards for trace elements.

[7] Chapter 5 focuses on Pathogen and Vector Attraction Reduction Requirements. On page 116, the Process to Further Reduce Pathogens is defined as "*using either the within-vessel composting method or the static aerated pile composting method, the temperature of the biosolids is maintained at 55/degree C or higher for 3 days. Using the windrow composting method, the temperature of the biosolids is maintained at 55/degree C for 15 days or longer. During the period when the compost is maintained at 55/degree C or higher, the windrow is turned a minimum of five times.*". The text is available at http://water.epa.gov/scitech/wastetech/biosolids/upload/2002_06_28_mtb_biosolids_503pe_503pe_5.pdf

[8] These requirements will ensure that emissions from storing waste at the composting facility are negligible, as justified in the "Organic Waste Composting Project Protocol" approved for use under the Climate Action Reserve.

qualified expert, as native plant communities are defined by their geography and are thus impacted by local conditions. Species composition may also change where grazing is discontinued due to factors unrelated to the project activity, such as extended periods of drought.[9] To reduce this risk, validation of the GHG project plan will include a review of the criteria used by the Qualified Expert to ensure that annual Project Stocking Rates will not contribute to erosion or otherwise negatively impact plant species composition. Changes to the annual Stocking Rate will be assessed during each subsequent verification to ensure changes were implemented in consultation with a Qualified Expert. The minimum Stocking Rate shall be set to ensure that plant community species composition is not negatively affected in response to soil quality improvement following compost application.

[9] Guidance on best practices for drought management can be found online at: http://pss.okstate.edu/publications/publications-master-list/copy_of_publications/forages/F-2870web.pdf

B. Project Boundaries

B.1 Geographic Boundary

B.1.1 Project Parcel

The GHG removals from carbon sequestration in the soil organic carbon pools of the Project Parcels are the focus of this methodology. The geographical boundary encompassing these Project Parcels is, therefore, the main geographic boundary of the Project. The geographical coordinates of the boundaries of each Project Parcel must be unambiguously defined by providing geographic coordinates.

New Project Parcels may be added to an existing Project after the start of the crediting period as long as all the applicability criteria are met for each individual Project Parcel, as outlined in ACR's most recent Standard.

B.1.2 Composting Facility (Optional)

In case GHG emission reductions from composting source material and avoidance of anaerobic decomposition are claimed as Emission Reduction Tons (ERTs) under this methodology, the composting facility shall be included in the geographic boundary. In this case, the project proponent(s) shall include a formal affidavit indicating that the emission reductions from composting source material and avoidance of anaerobic decomposition have never been claimed under any compliance or voluntary carbon registry. This affidavit would be issued by the project proponent(s) but will also include a signature from the owner of the composting facility attesting that the facility is not claiming carbon credits.

In case emission reductions from composting source materials are not claimed by the project participants, the composting facility is excluded from the Project's Geographic Boundary.

B.1.3 Stratification

This methodology encourages combining Project Parcels spread over a large geographic region within one Project to reduce costs. However, environmental, soil, and management conditions may not be homogeneous across a large geographic region. Non-homogeneous conditions may affect the validity of baseline calculations and additionality checks. Therefore, heterogeneous Project Parcels shall be subdivided into smaller units or strata that are considered homogeneous for the purpose of carbon accounting. A different set of input parameters to the model(s) for carbon accounting selected in Section D.1 shall be prepared for each different stratum. Parameters that shall be considered to stratify the Project Parcels are:

- Historical rangeland management practices
- Future rangeland management practices after the start of the Project

- Different soil types, especially special status soils (e.g., serpentine soils, histosols, etc.); official soil series description
- Ecological characteristics (soil texture, aspect, slope, hydrology, climate, plant communities)
- Degradation status (initial soil C content, soil bulk density)
- Differences in legally binding requirements affecting management of the Project (e.g., easement status of land, ownership)

The stratification must be conducted or approved by a Qualified Expert. A description and justification of the stratification procedure must be included in the GHG Project Plan. All subsequent procedures in this methodology, including baseline scenario identification and additionality tests must treat each identified stratum separately.

B.2 Greenhouse Gas Boundary

This section includes all sources, sinks, and reservoirs that are quantified in this methodology.

Baseline scenario:

- Emissions resulting from anaerobic decay of organic waste at a final disposal/treatment system (e.g., landfill or manure management system). This source is optional and may be omitted; doing so is conservative. If the composting facility will claim emission reductions from avoiding emissions from anaerobic decay of organic waste, this source may not be included in the GHG accounting for the project. If this source of emission reductions is claimed by the Project, the project proponent(s) shall include a formal affidavit indicating that no other party than the project proponent(s) have claimed the emission reductions from composting source material and avoidance of anaerobic decomposition under any compliance or voluntary carbon registry.
- Background changes of SOC, potentially related to continuous loss of soil organic carbon[10] of the Grassland as predicted through modeling.
- Enteric fermentation CH_4 emissions from ruminants grazing on project parcels.

Project scenario:

- Emissions resulting from the composting process, including active composting and curing of compost at project facilities. To avoid double deductions, this source of emissions shall be omitted in case the composting facility claims emission reductions for avoiding emissions from anaerobic decay of organic waste.
- Enteric fermentation CH_4 emissions from ruminants grazing on project parcels.
- Fossil fuel emissions from the transport of the finished compost to the Project Parcels.
- Emissions related to the land application of compost.

[10] Some evidence indicates that many grasslands are losing soil carbon (Chou *et al*. 2008, Ryals et al. submitted). Through compost additions, one may be able to slow down or reverse the carbon loss (Ryals & Silver 2013).

- Emissions of CO_2 and N_2O related to the decomposition of compost after application.
- Sequestration of carbon related to the increase in plant productivity on the grassland.
- Sequestration related to the transfer of compost into recalcitrant SOC pools.[11]

Fossil fuel emissions from transport of organic waste materials to final disposal/treatment system (e.g. garbage trucks, hauling trucks, etc.) under baseline conditions are assumed to be equal to the fossil fuel emissions from transporting waste materials to the compost facility in the project case[12], and are therefore not included in the GHG accounting (Brown et al. 2009).

The GHG emissions from storage of waste in the composting facility are assumed to be insignificant when the applicability conditions laid out in Section A.5 are followed.

[11] Only carbon stored in recalcitrant soil pools is considered sequestered

[12] Note that in case of on-farm composting, the fossil fuel emissions will likely be smaller in the project scenario. However, it is conservative to omit this extra emission reduction in case of on-farm composting.

Table 1. Overview of included Greenhouse Gas sources.

	Source	Gas	Included?	Justification/Explanation
Baseline	Project Parcels soil	CO_2	Yes	Emissions from decomposition of soil organic carbon
		CH_4	No	Non-flooded soils can be a source or sink of Methane but fluxes are negligible.
		N_2O	Yes	Nitrous oxide emissions from non-fertilized grassland soils are small but not negligible.
	Landfill or other waste sink	CO_2	Yes/No	Carbon dioxide emissions from organic materials are potentially significant in case these materials would have been deposited in landfills. This emission source is optional; omitting this source of emissions is conservative. However, when the composting facility claims emission reductions for avoiding emissions from anaerobic decay of organic waste, this source of emissions shall be omitted to avoid double deductions. This source must also be omitted in cases where the project developer does not know which landfill or other waste sink the material would have gone in the baseline scenario.
		CH_4	Yes/No	Methane emissions from organic materials are potentially significant in case these materials would have been deposited in landfills. This emission source is optional; omitting this source of emissions is conservative. However, when the composting facility claims emission reductions for avoiding emissions from anaerobic decay of organic waste, this source of emissions shall be omitted to avoid double deductions. This source must also be omitted in cases where the project developer does not know which landfill or other waste sink the material would have gone in the baseline scenario.
		N_2O	Yes/No	Nitrous oxide emissions from organic materials are potentially significant in case these materials would have been deposited in

				landfills. This emission source is optional; omitting this source of emissions is conservative. However, when the composting facility claims emission reductions for avoiding emissions from anaerobic decay of organic waste, this source of emissions shall be omitted to avoid double deductions. This source must also be omitted in cases where the project developer does not know which landfill or other waste sink the material would have gone.
	Ruminants	CH_4	Yes	Methane emissions from enteric fermentation from ruminants grazing on the land.
	Fossil fuel emissions from transport of organic waste to landfill	CO_2	No	Assumed to be equivalent to fossil fuel emissions from transport of organic waste to composting facility.
	Fossil fuel emissions from transport of imported forage	CO_2	No	Assumed to be conservative as project scenario is likely to require less importation of feed.
Project	Project Parcels soil	CO_2	Yes	Additional CO_2 emissions from compost application may occur and are included.
		N_2O	Yes	Additional N_2O emissions from compost application may occur and are included.
		CH_4	No	Non-flooded soils can be a source or sink of Methane but fluxes are negligible
	Ruminants	CH_4	Yes	Methane emissions from enteric fermentation from ruminants grazing on the land.
	Emissions due to leaching	N_2O	No	Secondary emissions from leachates of the composted material are negligible due to the complex nature of compost and the low nitrogen content of compost.
	Fossil fuel emissions from transport of organic waste	CO_2	No	Assumed to be equivalent to fossil fuel emissions from transport

	to the compost facility			of organic waste to landfill.
	Fossil fuel emissions from transport of compost to project parcel and application	CO_2	Yes	Assumed to be additional to the fossil fuel emissions from transport of organic waste to landfill or composting facility.
	Fossil fuel emissions from transport of imported forage	CO_2	No	Assumed to be conservative as project scenario is likely to require less importation of feed.
	Emissions due to composting	CO_2	No	Carbon dioxide emissions released during composting are biogenic. These emissions are not quantified in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5: Waste, Chapter 4: Biological Treatment of Solid Waste and therefore are not included in this calculation of project emissions.
		CH_4	Yes/No	Some methane may be produced during composting. To avoid double deductions, this source of emissions shall be omitted in case the composting facility claims emission reductions for avoiding emissions from anaerobic decay of organic waste.
		N_2O	No	Nitrous oxide emissions during composting are negligible.

Table 2. Overview of included pools (baseline and project)

Pool	Included in emissions reductions quantification	Rationale
Above-ground non-woody biomass	No	The above-ground non-woody biomass pool will not be directly quantified in the protocol, however during decomposition some carbon from this pool will eventually enter the soil carbon pool that is accounted for and quantified by the methodology.
Below-ground non-woody biomass	No	The below-ground non-woody biomass pool will not be directly quantified in the protocol, however during decomposition some carbon from this pool will eventually enter the soil carbon pool that is accounted for and quantified by the methodology.
Litter	No	The litter pool will not be directly quantified in the protocol, however during decomposition some carbon from this pool will eventually enter the soil carbon pool that is accounted for and quantified by the methodology.
Dead wood	No	Not a major pool affected by project activities.
Soil	Yes	Potentially significantly affected by project activities. The increased forage production and the addition of compost are expected to increase the soil organic content.

B.3 Temporal Boundary

The project start date shall coincide with the first compost application event. The minimum project term will be 40 years due to the fact that the ERTs claimed as a result of the compost additions to grassland soils are calculated based on the stability of the "intermediate" and "passive" C pools being greater than 40 years (see Sections A.3 and D.2). The crediting period is defined by the ACR Standard as the finite length of time for which a GHG Project Plan is valid, and during which a project can generate offsets against its baseline scenario.[13] The crediting period for each project will be 10 years and validation of the GHG Project Plan will occur once per crediting period. Crediting periods are limited in order to require project proponents to reconfirm at set intervals that the baseline scenario remains realistic, credible, additional, and that the current best GHG accounting practice is being used. Since ACR places no limit on the number of crediting period renewals, the project proponent may renew the crediting period in 10-year increments thereafter, provided that the project still meets the protocol requirements. The

[13] The current version of the ACR Standard can be found online at http://americancarbonregistry.org/carbon-accounting/standards-methodologies/american-carbon-registry-standard

methodology allows for multiple compost applications as long as there are at least three years between each application and the new application rate is explicitly reviewed and approved by a Qualified Expert. The three-year rule, combined with the review of the Qualified Expert, is intended to allow enough time between compost additions so that any potential negative impacts on plant communities can be detected and mitigated before a new application is scheduled.

C. Procedure for Determining the Baseline Scenario and Demonstrating Additionality

Emission reductions from avoidance of anaerobic decomposition have very different additionality considerations than emission reductions from direct and indirect increases in SOC. Project proponents who are not claiming any ERTs from avoidance of anaerobic decomposition do not have to consider the additionality requirements related to this source of emission reductions, covered in Section C.1. Since all projects using this methodology will add compost to Grazed Grasslands, all project proponents shall follow the additionality requirements related to direct and indirect increases in SOC, covered in Section C.2.

C.1 Additionality of Emission Reductions from Avoidance of Anaerobic Decomposition

Project proponents shall use ACR's three-prong approach[14] to demonstrate additionality. Specifically, in cases where ERTs from landfill diversion are obtained, it must be demonstrated that the source material used for composting was diverted from a landfill or anaerobic manure storage facility. ERTs cannot be claimed in instances where the landfill or anaerobic processing facility that would otherwise receive the waste material cannot be identified, or if the facility from which source material was diverted already captures methane. Evidence must be provided demonstrating that the specific source of the waste material used for composting (e.g., the specific waste collector) has been deposited in a landfill or storage under anaerobic conditions (in the case of manure) for a period of five years prior to the project's starting date. Valid evidence includes economic analyses, reports, peer-reviewed literature, industry group publications, surveys, etc. Note that examples of the application of these approaches are provided in Section C.1.2.

C.1.1 Co-composting

Often, multiple waste sources are composted together to get an optimal composting C-to-N ratio and increase the waste streams that can be processed. This is referred to as co-composting. In case one of the materials used during co-composting is non-additional, the proportion of the waste that is additional shall be recorded and used in subsequent calculations in Section C.2 as parameter $f_{diverted}$. In case all the waste material is additional, $f_{diverted}$ shall be set to 1. The $f_{diverted}$ factor is used in subsequent calculations to discount any GHG benefits so that only additional benefits are counted.

[14] The three-prong test is described in detail in the ACR Standard.

C.1.2 Examples of determining additionality through diversion of waste materials

- Studies by *Biocycle Magazine*, referenced in a report published by the EPA in 2008,[15] estimate that, at a national level, 97.4% of solid food waste (e.g., milk solids, condemned animal carcasses, meat scraps, and pomace wastes from wineries) were landfilled in 2007. Therefore, compost made from solid food waste is additional without the need for any further evidence.
- The same report published by the EPA in 2008 estimated that 35.9% of the total quantity of yard waste was landfilled. Therefore, a project developer must demonstrate that the specific source of the waste material, i.e., the waste collector of a specific municipality, has landfilled the yard waste for a period of five years prior to the Project's starting date.
- California generates 750,000 dry tons of biosolids, the by-product of channeling human waste through treatment plants and collection systems (California Association of Sanitation Agencies). In total, 54% is land applied and 16% is composted according to statistics from CalRecycle, available at http://www.calrecycle.ca.gov/organics/biosolids/#Composting. Therefore, a project developer using compost derived from biosolids must demonstrate that the specific source of the biosolids, i.e., the biosolids of a specific municipality, have been landfilled in the past.
- The biosolids from sources that are already land-applied (currently 54%) are not compost and not considered additional under this methodology. However, these biosolids could potentially be co-composted by blending it with carbonaceous material such as paper diverted from landfills. The resulting compost is eligible to be used within this methodology on the condition that $f_{diverted}$ is set to the percentage of the compost feedstock (biosolids plus carbonaceous material) actually diverted from landfill.

C.2 Additionality of Emission Reductions from Increases in SOC

The additionality of emission reductions from direct or indirect increases in SOC related to the addition of compost to Grazed Grassland can be tested in a straightforward fashion using ACR's standard three-prong approach, based on Regulatory Surplus, Common Practice, and Implementation Barriers.

C.3 Baseline Determination

Once ACR's three-prong test is passed, the baseline management is set as a continuation of the historical management. The historical management is defined by acquiring the following three parameters for a period of at least five years[16] before the start of the Project:

- Stocking rates

[15] Municipal Solid Waste in the United States. 2007 Facts and Figures. Environmental Protection Agency Office of Solid Waste (5306P). EPA530-R-08-010. Available at http://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1001UYV.PDF

[16] Note that in areas with a longer history of fire, significant changes in plant cover, or other disturbances, more details may be needed to adequately parameterize PBM models.

- Stocking periods
- Incidence of fires

The historical grazing management shall be duly described. These management parameters and other site-specific parameters that are required to define the baseline are included in the list of parameters available at model validation (Section E.1). Key parameters such as the site-specific grazing intensity, soil properties, and climate will be required for all baseline model validation efforts. However, since process based models vary in the ancillary input parameters that they require, appropriate discretion on what must be included will be given to those tasked with validating the model for a given site.

Baseline stocking rate shall be the average of at least 3 of the last 5 years prior to the project start date. The project proponent shall select the most representative years to include and must provide a verifiable justification of the year selection in the GHG project plan.

D. Quantification of GHG Emission Reductions and Removals

D.1 Requirements for Models used for Quantifying GHG emissions and removals

This methodology does not prescribe a model to quantify changes in SOC and soil N_2O emissions. A variety of models are eligible to quantify GHG emissions and removals on the condition that (1) project developers demonstrate the use of the selected model is sufficiently accurate for their study area, as explained in the remainder of this section, and (2) an appropriate uncertainty deduction is applied. Either PBMs or empirical models such as emission factors may be used. Multiple models may be used during the carbon accounting. For example, it is allowed to use a PBM for one variable, such as SOC, and use a Tier-2 Emission Factor for N_2O emissions. The remainder of this section contains general requirements related to the use of Tier-2 Empirical Models and PBMs.

The uncertainty deduction shall have two components: one component related to the inherent, or structural, uncertainty from the model, and another component related to the variability of the input data, such as the variability of the N content in the compost, or the soil texture. Each of the three potential quantification approaches detailed below contains a section on how to calculate structural uncertainty. The structural uncertainty shall further be adjusted for aggregation. The input uncertainty shall be calculated using a Monte Carlo approach and using a 90% confidence level. The two sources of uncertainty, structural uncertainty and input uncertainty, shall simply be summed to calculate the total uncertainty. For the N_2O and ΔSOC components, the total uncertainty shall be calculated as:

$$u_{total} = \frac{u_{struct}}{\sqrt{n}} + u_{input}$$

u_{total}	=	Total uncertainty deduction [MT CO_2-eq]
u_{struct}	=	Structural uncertainty deduction related to the use of a specific model [MT CO_2-eq]
n	=	Number of Project Parcels or the total size of the Project Parcels in hectares divided by 250, whichever is smallest [-]
u_{input}	=	Input uncertainty deduction [MT CO_2-eq]

D.1.1 Tier-2 Empirical Models

Project proponents may develop Tier-2 Empirical Models, which may be used once they appear in the peer-reviewed scientific literature. Project Proponents shall justify in the GHG Project Plan that the sampling locations to create the regionally applicable Tier-2 Empirical Models are representative for the Project. Data from at least five sites across two years must be used to calculate the Tier-2 Empirical Model.

STRUCTURAL UNCERTAINTY FOR TIER-2 EMPIRICAL MODELS A bootstrapping method of resampling shall be used to estimate the deviation between measured and modeled emission reductions. The structural uncertainty shall be calculated as the half-width of the 90% confidence interval around the deviations and shall be deducted from the final ERTs.
INPUT UNCERTAINTY FOR TIER-2 EMPIRICAL MODELS The input uncertainty shall be calculated using simple propagation of errors around input parameters such as the quantity of carbon or nitrogen added through the compost additions. The error shall equal the half-width of the 90% confidence interval, e.g., from the error around the N content of the compost.

D.1.2 Process-based Biogeochemical Models (PBMs)

PBMs such as Century, Daycent,[17] EPIC, ROTH-C, or DNDC may be used on the condition that they are validated for the conditions of the Project Parcels and for the specific variable that is under consideration (i.e., annual change in SOC content, SOC content, or annual N_2O emissions). The PBM must be peer reviewed in at least three scientific publications. The PBMs indicated above meet the requirement on the scientific publications. In addition, the project proponents must develop an objective and unambiguous operating procedure to parameterize and run the PBMs. This procedure document must spell out how every input parameter shall be set. The applicability of the selected model is dependent on the soil type(s), climate, and broad management of the area in which the model is applied. Therefore, it is required to (1) validate the model for the conditions of the Project Parcels, and (2) specify the conditions under which the model's operating procedures remain valid. The validation of a model shall be conducted by comparing field measurements to model predictions. Once model validation has been completed, it does not need to be repeated.

The nature of geographic variability in conditions requires that some degree of judgment to be left to the model validator in order to determine the number of field measurement that will be adequate for local circumstances. Heterogeneous conditions may require more samples, while flatter or otherwise homogenous scenarios may require fewer.

The slope of the relation between modeled and measured values shall be between 0.9 and 1.1 as tested using two one-sided t-tests using a significance of 90%.

[17] Daycent is a version of the Century model with a daily time step, and these two models are essentially the same if it comes to simulating SOC. However, DAYCENT can also simulate soil N_2O and CH_4 emissions whereas Century cannot.

STRUCTURAL UNCERTAINTY FOR PBMs

For PBMs, the structural uncertainty for soil C sequestration shall be calculated as the half-width of the 90% confidence interval around the mean deviation between modeled and measured differences between baseline and project SOC quantities, multiplied by 44/12 to convert the uncertainty into CO_2-equivalents, as is commonly done in GHG accounting methodologies. This uncertainty shall be noted and subtracted from the final ERTs, as explained in Section D.4. An uncertainty for N_2O emissions shall be calculated similarly as the half-width of the 90% confidence interval around the mean deviation between modeled and measured differences of project N_2O emissions, except for a multiplication with 310 x 44 / 28, to account for the radiative forcing and molecular weight of N_2O.

INPUT UNCERTAINTY FOR PBMs

The input uncertainty for PBMs shall be calculated using a Monte Carlo analysis based on a multivariate distribution of the input parameters. At least 200 different draws out of this multivariate distribution for both the Baseline Scenario and the Project Scenario and subsequent model simulations must be executed. For each of the draws of the distribution, one emission reduction is calculated by subtracting the Baseline emissions from the Project emissions. Calculate the uncertainty as the value corresponding to the 10% quantile for the distribution of values.

D.2 Baseline Emissions

D.2.1 General Equation

If avoided landfill emissions are claimed by the project, the emissions of the waste material when deposited in a landfill must be calculated for each project parcel separately using the following equations:

[EQ 1]

$$BE(y,i) = f_{diverted}(BE_{landfill}(y,i)) + BE_{\Delta SOC}(y,i) + BE_{N2O}(y,i)$$

Sub-equations for Components:

[EQ 2]

$$BE_{landfill,}(y,i) = BE_{landfill.CH4} - \left(\frac{\sum_{i=1}^{j} W_j \cdot DOC_j \cdot DOC_f}{40} \cdot \frac{44}{12}\right)$$

[EQ 3]

$$BE_{\Delta SOC}(y,i) = A(i) \cdot \Delta SOC(y,i) \cdot \frac{44}{12}$$

[EQ 4]

$$BE_{N2O}(y,i) = A(i) \cdot CE_{N2O}(y,i)$$

Where:

$BE(y,i)$	=	The total sum of the baseline emissions associated with project parcel i during year y. See EQ 1 above. [MT CO_2-eq yr^{-1}]
$f_{diverted}$	=	The percentage of the waste source that is additional. See Section C.1.1.
$BE_{landfill}(y,i)$	=	The cumulative baseline emissions of Methane and Carbon Dioxide from waste material at the landfill under the baseline scenario during year y. To be set to 0 when emission reductions at the landfill claimed by an entity other than the Project Proponents. See EQ 2 above. [MT CO_2-eq yr^{-1}]
$BE_{landfil,CH4}(y,i)$	=	The cumulative baseline Methane emissions from waste material at the landfill or waste storage pond under the baseline scenario during year y. To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents. [MT CO_2-eq yr^{-1}]
W_j	=	Amount of organic waste type j prevented from disposal, expressed as dry mass. To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents.
DOC_j	=	Fraction of waste type j that is degradable organic carbon (by weight). To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents.
DOC_f	=	Fraction of degradable organic carbon (DOC) that fully decomposes to CO_2. To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents.
$\frac{44}{12}$	=	Factor to convert the mass of C to CO_2.
$BE_{\Delta SOC}(y,i)$	=	Annual CO_2 emissions from the change in soil organic C for project parcel i during year y of the baseline scenario, calculated using a model that

meets the requirements of Section D.1. The sign of this component is determined by the baseline trends in SOC, which can be either positive when soil is a net source of CO_2 or negative when it is net sink of CO_2. See EQ 3 above. [MT CO_2-eq yr^{-1}]

$A(i)$	=	Size of project parcel i. [ha]
$\Delta SOC(y,i)$	=	Change in baseline soil organic carbon of project parcel i during year y of the baseline scenario, calculated using a model that meets the requirements of Section D.1. [MT C ha^{-1} yr^{-1}]
$BE_{N2O}(y,i)$	=	Cumulative baseline Nitrous Oxide emissions from soils of the project parcel i during year y of the baseline scenario, expressed in CO_2-eq. To be calculated using a model that meets the requirements of Section D.1. See EQ 4 above. [MT CO_2-eq yr^{-1}]
$CE_{N2O}(y,i)$	=	Annual N_2O emissions rate from soils of project parcel i during year y of the baseline scenario. To be calculated using a model that meets the requirements of Section D.1. [MT CO_2-eq ha^{-1} yr^{-1}]

Note that the “44/12” factor converts a mass of carbon into a mass of Carbon Dioxide. In addition, the quantity $W_j \cdot DOC_j \cdot DOC_f$ represents the cumulative mass of carbon that is decomposed after 40 years in a landfill for waste material. Therefore, $\frac{44}{12}\frac{\sum_{i=1}^{j} W_j \cdot DOC_j . DOC_f}{40}$ represents the annual CO_2 emissions from decomposition of the waste material in the landfill under the baseline scenario.

D.2.2 Quantification Procedure

The value $BE_{landfill,CH4}(y,i)$ shall be calculated as the quantity $BE_{CH4,SWDS,y}$ using the CDM tool “Tool to determine Methane emissions avoided from disposal of dumping waste at a solid waste disposal site.” The quantities W_j, DOC_j, and DOC_f shall be set according to this CDM tool. Finally, the quantity $BE_{\Delta SOC}(y,i)$ shall be calculated using a model that meets the requirements of Section D.1.

D.3 Project Emissions

D.3.1 General Equation

[EQ 5]

$$PE(y,i) = PE_{\Delta SOC}(y,i) + PE_{N2O}(y,i) + PE_{fuel}(y,i) + PE_{compost,CH4}(y,i)$$

Sub-Equations for Components

[EQ 6]

$$PE_{\Delta SOC}(y,i) = A(i) \cdot \left(\frac{\Delta SOC_d(40)}{40} + \Delta SOC_i(y,i) \right) \cdot \frac{44}{12}$$

[EQ 7]

$$PE_{N2O}(y,i) = A(i) \cdot CE_{N2O}(y,i)$$

Where:

$PE(y,i)$	=	The total sum of the project emissions during year y. [MT CO_2-eq yr^{-1}]
$PE_{\Delta SOC}(y,i)$	=	Annual CO_2 emissions from the change in soil organic C for project parcel i during year y of the project, calculated using a model that meets the requirements of Section D.1. The sign of this component is determined by the baseline trends in SOC, which can be either positive when soil is a net source of CO2 or negative when it is net sink of CO_2. See EQ 6 above. [MT CO_2-eq yr^{-1}]
$A(i) \cdot$	=	Size of project parcel i. [ha]
$\Delta SOC_d(40)$	=	Change in carbon from added compost remaining in the soil at year 40. To be calculated using a model that meets the requirements of Section D.1 [MT C ha^{-1} yr^{-1}]
$\Delta SOC_i(y,i)$	=	Annual indirect change in soil carbon due to increases in plant productivity during year. To be calculated using a model that meets the requirements of Section D.1. [MT C ha^{-1} yr^{-1}]
$\frac{44}{12}$	=	Factor to convert the mass of C to CO_2.
$CE_{N2O}(y,i)$	=	Cumulative Nitrous Oxide emissions from soils of the project parcel i during year y of the project, expressed in CO_2-eq. To be calculated using a model that meets the requirements of Section D.1. See EQ 7 above. [MT CO_2-eq yr^{-1}]
$PE_{N2O}(y,i)$		Annual N_2O emissions rate from soils of project parcel i during year y of the project. To be calculated using a model that meets the requirements of Section D.1. [MT CO_2-eq ha^{-1} yr^{-1}]
$PE_{fuel}(y,i)$	=	Fuel emissions from transportation to the project parcel and application of the organic material on the land during year y. [MT CO_2-

eq yr^{-1}]

$PE_{compost,CH4}(y,i)$ = At a year when compost is added, e.g., when $y = 1$, the Methane emissions emitted during composting of the organic material, expressed in CO_2-eq. At all other years, this quantity is to be set to 0. When emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents, this quantity is to be set to 0 at all times to avoid double discounting [MT CO_2-eq yr^{-1}]

Because $\Delta SOC_d(40)$ represents the compost carbon remaining after 40 years, $\frac{\Delta SOC_d(40)}{40}$ represents the fraction of the compost carbon remaining that can be claimed as a GHG benefit for every year of the project period.

D.3.2 Quantification Procedure

The quantities $\Delta SOC_d(40)$, $\Delta SOC_i(y)$, and $PE_{N2O}(i,y)$ shall be calculated using a Tier-2 Empirical Model, or a PBM. If a PBM is used that is based on conceptual C-pools, only pools that have a turnover time of greater than 2 years shall be counted towards $\Delta SOC_d(40)$ and $\Delta SOC_i(y)$. This provision is included to avoid incorporating carbon sources that are readily decomposable as carbon sequestration. $\Delta SOC_d 40$ and $\Delta SOC_i(y)$ must be *reduced* by an appropriate discounting factor, while $PE_{N2O}(i,y)$ must be increased by an appropriate discounting factor, as specified in Section D.1.

$PE_{fuel}(i,y)$ is the sum of the emissions from fuel use from transportation and the fuel use from application of the compost. The fuel use from transportation of the compost shall be calculated using the CDM tool “Project and leakage emissions from road transportation of freight.” The fuel use from application of the compost shall be calculated using the CDM tool “Tool to calculate project or leakage CO2 emissions from fossil fuel combustion.”

The project proponent must account for any increase in enteric emissions associated with the project activity, likely due to an increased stocking rate. The ACR Tool for Tier I Estimation of Emissions from Livestock Management Projects shall be used to calculate the net enteric emissions. The project proponent must enter all baseline and project scenario data required by the “2. Enteric” tab in the tool (all other data input tabs can be excluded). The value for the net emissions from Enteric shall be pulled from cell J13 of the “6. X-ANTE” tab and included in equation 8 below. If the result is a positive number (emission reductions), it will be considered “zero” for the purposes of conservativeness.

$PE_{compost,CH4}(i)$ shall be calculated using the most recent default emission factor available from the IPCC for the CH_4 emissions from biological treatment of waste.[18]

[18] As of the writing of this methodology, the emissions factor is found in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5: Waste, Chapter 4: Biological Treatment of Solid Waste.

D.4 Summary of GHG Emission Reduction and/or Removals

[EQ 8]

$$ER_y = \sum_{i=1}^{nrParcels} \left(PE(y,i) - BE(y,i)\right) + \Delta CH_4 enteric - u_{total}$$

Where:

ER_y	=	GHG emissions reductions and/or removals in year y [tCO_2-eq yr^{-1}]
$nrParcels$	=	Number of individual Project Parcels
$PE(y,i)$	=	Project emissions in year y for individual parcel i [$MTCO_2$-eq yr^{-1}]
$BE(y,i)$	=	Baseline emissions in year y for individual parcel i [$MTCO_2$-eq yr^{-1}]
$\Delta CH_4 enteric$	=	Enteric emissions associated with an increase in stocking rate over each project parcel. Either enter zero, or the value from cell J13 of the 6.T-XANTE tab of the *ACR Tool for Estimation of Emissions from Livestock Management Projects*, whichever is less. [$MTCO_2$-eq yr^{-1}]
u_{total}	=	Total uncertainty deduction [MT CO_2-eq]

D.5 Leakage

Emissions leakage refers to instances where activities to reduce emissions from a project parcel may result in increased emissions due to activities and market shifts occurring at locations beyond the project boundaries. Available field research suggests that the addition of compost to grasslands will generally increase soil carbon and the production of forage for livestock. Although not directly connected to the project activities, increases or decreases in stocking rate have been accounted for in this methodology in the spirit of whole-system accounting and conservativeness.

Voluntary and significant stocking rate reductions (more than three percent of the baseline) will make the project ineligible for crediting over the quantification period, until the stocking rate has returned to within -3% of the baseline level. Monitoring and reporting would be required to continue to ensure permanence of sequestered carbon. A leakage deduction will not need to be taken for any stocking rate reductions of greater than 3% from the baseline if justifiably attributable to verifiable instances of natural disaster, disease or otherwise that significantly reduces the stocking rates involuntarily. These circumstances must be verified by an accredited VVB with sufficient documentation including an attestation by the Proponent, demonstrating that this circumstance would have also affected the baseline in a business as usual situation.

E. Monitoring

E.1 Data and Parameters Available at Validation

Various data elements related to compost, soil, weather, and management must be available at model validation. The specific data elements required are detailed below, and explicitly outlined in Appendix A.

- **Compost**. The following data must be available for each batch of compost. Unless sound data for these parameters are available (e.g., as a result from a certification), the compost must undergo laboratory tests.
    - The **carbon concentration** is required to convert mass of dry compost to mass of carbon added, which is a property that is required by a model.
    - The **nitrogen concentration** is required to convert mass of dry compost to mass of nitrogen added, which is needed to verify the applicability conditions and may also be required for the model used.
    - The **C:N ratio** is required to be calculated based on the aforementioned data availability.
    - It is advised, but not required, to include the **phosphorus concentration** in the elemental analysis, as this may improve the models' ability to simulate changes in SOC related to compost addition.
    - The **bulk density** is required to convert a volume of compost, a very common unit used by compost facilities, spreaders, and transporters, into a mass of compost.
    - The **moisture content** is required to convert a mass of moist compost into dry compost.
    - The **pH** of the compost must be measured and recorded

  In addition, the following information shall be obtained if available:
    - Source of the compost raw materials
    - Fate of the organic matter under baseline conditions
- **Soil**. At least three soil samples per parcel shall be taken within each stratum representing at least 0-20 cm. If the relative standard error among the three samples is greater than 20%, more samples shall be taken until the relative standard error is less than 20%. Project developers may choose to take more and deeper samples than this minimum requirement, which is beneficial in improving both model runs and the potential for demonstrating carbon sequestration at greater depths. Samples shall not be composited. The following measurements shall be conducted on the soil samples based on standard analytical protocols described in the Soil Science Society of America Methods of Soil Analysis (Sparks et al. 1996):
    - Total soil carbon
    - Soil texture
    - Soil bulk density
    - Soil pH

  Note that the project developer is allowed to measure the soil carbon at the start of the project *after* compost application on reference locations within the Project Parcels that did not receive the compost application. The latter is feasible when reference locations are shielded from compost application by putting a tarp at that location and removing the compost that is deposited on the tarp before soil carbon analysis.

- **Historical weather**. Daily minimum and maximum temperatures and rainfall shall be obtained for a period of five years before the start of the Project. Historical weather data must come from the nearest weather station or other published weather records (such as Daymet).
- **Project weather**. Daily minimum and maximum temperatures and rainfall shall be obtained through the duration of the Project. This data must come from the nearest weather station or other published weather records (such as Daymet).
- **Historical management**. The following parameters shall be provided for each stratum for a period of at least 5 years before the start of the project. Additional years of data are highly recommended if significant changes in land cover or management are known to have occurred
    - Stocking rates
    - Stocking periods
    - Incidence of fires
- **Project management**. The following parameters shall be provided for each stratum of a project
    - Project population
    - Stocking rate
    - Stocking period
    - Average stocking rate (average over all project years)
    - Minimum stocking rate
    - Maximum stocking rate
    - Incidence of fires
- **Plants and plant communities**. A land assessment by a Qualified Expert must be provided that this consistent with standard NRCS ecological site descriptions[19]. This land assessment report should include a stratification of the land and a description of plant productivity (which is inclusive of species type and forage quality) into three groups: “poor”, “medium”, or “high”. Values of net primary productivity are required in order to better determine yield response.. These values should be obtained through the creation of an exclusion area where livestock are not able to graze so that primary productivity can be measured in dry matter/unit area. The land assessment report shall contain a broad description of the plant communities, percentage cover of natives as well as any problems with invasive weeds before the start of the project. Finally, the land assessment report shall also contain an assessment of the fire risk.

In addition to the parameters described above, various additional soil and site parameters may be needed to parameterize the model runs. The onus is on the project developer to demonstrate that a model was used and parameterized correctly.

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[19] Information on NRCS ecological site descriptions may be found online at http://www.nrcs.usda.gov/wps/portal/nrcs/main/national/technical/ecoscience/desc/

E.2 Data and Parameters Recorded during Compost Application

In addition, a description of the application procedure must be provided. This description must include:

- Application date
- Machinery used
- Application method
- Broadcast rate (tons/ha)
- Rationale for application procedure and reference source if available

Receipts of compost purchase, transportation, and application shall be kept and made available to the validator. In addition, it is strongly recommended to take pictures during the application of the compost. All data collected as part of monitoring must be archived electronically and be kept at least for two years after the end of the project crediting period.

E.3 Data and Parameters Monitored after Compost Application

Total soil carbon, texture, bulk density and pH shall be measured for the 0-20cm soil depth at the start of the project and at least every 10 years thereafter as described in Section E.1. In addition, an update of the land assessment report by a Qualified Expert shall be conducted two and five years after compost application.

Actual weather shall be recorded from the same weather station used during model validation. In addition, Stocking Rates and periods shall be provided for each stratum for every year after the start of the project. Every incidence of wildfire shall be reported and used in ex-post simulation, if the selected model allows.

E.4 Updating Models and Model Structural Uncertainty Deduction

The model uncertainty must be updated at least every 10 years, which is also the time frame of a project's crediting period extension. However, it is allowed to update a model's structural uncertainty deductions more frequently as new field data becomes available during a project's crediting period. The new structural uncertainty deductions must be proposed in a monitoring report and explicitly approved by a VVB before ERTs are issued using the new structural uncertainty deductions. The calculation of Baseline and Project emissions must always use the same structural uncertainty deductions.

In addition to updating the structural uncertainty deduction, it is allowed to use (a) different model(s) after the start of the project. For example, it is allowed to switch from a Tier-2 Empirical Model to a PBM. All requirements related to the selection of the model(s) and the calculation of its/their structural uncertainty deduction must be met. This switch must be proposed in a monitoring report and explicitly approved by a VVB before ERTs are issued using the new model(s). The calculation of Baseline and Project emissions must always use the same modeling approach.

F. Permanence

Projects must be consistent with the ACR Standards for permanence, which require proponents to sign ACR's risk mitigation agreement.[20] This risk mitigation agreement legally requires the project proponents to conduct a risk assessment using the latest ACR-approved Non-Permanence Risk Analysis and Buffer Determination tool[21]. The result of this assessment is an overall risk category for the project, translating into a percentage or number of ERTs that the project proponent must deposit, at each new ERT issuance, into a shared non-permanence buffer pool managed by ACR. For instance, ERTs contributed from the Project or those purchased from other Projects may be used to satisfy this buffer pool requirement. Alternatively, the proponent may also meet its legal obligations by providing evidence of sufficient insurance coverage with an ACR-approved insurance product. Reversals need only be fully compensated when they occur during the period in which monitoring is required (i.e. during the minimum project term).

In addition, the proponent shall take measures to reduce the risk of reversal from the following types of reversals that may occur, namely inundation, land use conversion and tillage. Every incidence of inundation due to extensive rainfall or large scale flooding of rivers and streams that lasts for longer than two months in a given crediting year shall be reported. All areas that were inundated for longer than two months shall be excluded from crediting during that year. It is likely that the boundaries of the flooded area do not coincide with the boundaries of strata established during stratification. Therefore, the flooded areas shall be cut out from existing strata for the duration of the year during which the flood happened. If the flood straddles a crediting year, ERTs may not be generated for both years during which the flood occurred. Unless specific circumstances indicate that that the Project Proponent flooded the parcel intentionally, inundation shall be considered a non-intentional reversal according to terms of the risk mitigation agreement.

Any conversion of a project parcel to any other land use than Grazed Grassland, such as annual arable crops or development, will immediately exclude this parcel from generating future ERTs. Unless the soil carbon loss due to the conversion on this Project Parcel is duly replaced by acquiring ERTs from this or other projects and project types, all ERTs from previously stored soil carbon shall be considered a reversal of previously credited ERTs. In addition to the aforementioned risk mitigation mechanisms discussed above, the project proponent may replace the reversed ERTs with ERTs issued from other project parcels within the same project within two years of the date of the conversion. Note that even after replacing the ERTs lost to conversion, the project parcel that was converted must be permanently excluded from issuing ERTs. All other Project Parcels within the Project are not affected by one project

[20] The current version of the ACR Standard can be found online at http://americancarbonregistry.org/carbon-accounting/standards-methodologies/american-carbon-registry-standard

[21] The Tool for AFOLU Non-Permanence Risk Analysis and Buffer Determination can be found online at http://www.v-c-s.org/sites/v-c-s.org/files/Tool%20for%20AFOLU%20Non-Permanence%20Risk%20Analysis%20and%20Buffer%20Determination.pdf

parcel being converted to another land-use. In case only part of a parcel was converted to another land use, it is allowed to pro-rate the reversed ERTs or re-purchase ERTs based on the relative proportion of the conversion within the parcel. Land use conversion shall be considered an intentional reversal according to terms of the risk mitigation agreement.

In the unlikely case that a tillage event occurs on the Project Parcel without a conversion of the grassland to agricultural or any other land use, all soil carbon ERTs previously issued from this Project Parcel will be considered to have been reversed unless the carbon losses resulting from the tillage event on the Project Parcel are duly accounted for and compensated by retiring existing ERTs from the current or other projects and project types. Similarly to land conversions, this carbon loss shall be verified in a monitoring report and must be verified by a VVB. In addition, unless such a true-up occurs, the project parcel shall be permanently excluded from issuing ERTs. Tillage shall be considered an intentional reversal according to terms of the risk mitigation agreement.

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G.1 Sources

This methodology has adopted aspects of the following sources for its carbon accounting:

- ACR's Grazing Land and Livestock Management (GLLM) Methodology, available at http://americancarbonregistry.org/carbon-accounting/standards-methodologies/grazing-land-and-livestock-management-gllm-ghg-methodology
- "Adoption of sustainable agricultural land management (SALM)," available at http://www.v-c-s.org/sites/v-c-s.org/files/SALM%20Methodolgy%20V5%202011_02%20-14_accepted%20SCS.pdf, submitted to and approved by the Verified Carbon Standard (VCS); developed by the World Bank's BioCarbon fund
- Clean Development Mechanism (CDM) "Tool to determine Methane emissions avoided from disposal of dumping waste at a solid waste disposal site," available at http://cdm.unfccc.int/EB/041/eb41_repan10.pdf
- CDM tool "Project and leakage emissions from road transportation of freight," available at http://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-12-v1.pdf
- CDM "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion," available at http://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-03-v2.pdf
- "Organic Waste Composting Project Protocol," (Version 1.0), available at http://www.climateactionreserve.org/how/protocols/organic-waste-composting/, approved for use under the Climate Action Reserve.

Appendix A: Parameter List

A.1 Parameters for Baseline and Project Emissions, and Overall Emissions Reductions and/or Removals Quantification

Parameter	$BE(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	Sum of baseline emissions associated with project parcel *i* during year *y*
Relevant Section	D.2, D.4
Relevant Equation(s)	1, 8
Source of Data	Calculated in equation 1
Data Requirements	$BE_{landfill}(y,i)$, $BE_{landfill,CH4}(y,i)$, $BE_{\Delta SOC}(y,i)$
Collection Procedure	Based on calculations from equations 2, 3, and 4
Revision Frequency	At the start of each crediting period
Comments	

Parameter	$f_{diverted}$
Units	%
Description	The percentage of the waste source that is additional
Relevant Section	C.1.1, C.1.2, D.4
Relevant Equation(s)	1
Source of Data	Determination through 8.1.1
Data Requirements	Compost source materials and additionality
Collection Procedure	Project Proponent obtains records of waste diverted from landfill to compost facility.
Revision Frequency	Each time Project Proponent uses new composting facility.
Comments	

Parameter	$BE_{landfill}(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	The cumulative baseline emissions of Methane and Carbon Dioxide from waste material at the landfill under the baseline scenario during year y
Relevant Section	D.2
Relevant Equation(s)	1, 2
Source of Data	Calculated in equation 2
Data Requirements	$BE_{landfill.CH4}$, W_j, DOC_j , DOC_f
Collection Procedure	Project Proponent obtains records of waste diverted from landfill to compost facility.
Revision Frequency	Each time Project Proponent uses new composting facility
Comments	To be set to 0 when emission reductions at the landfill claimed by an entity other than the Project Proponents

Parameter	$BE_{landfill,CH4}(y,i)$
Units	MT CO_2-eq yr^{-1}

Description	The cumulative baseline Methane emissions from waste material at the landfill or waste storage pond under the baseline scenario during year y
Relevant Section	D.2
Relevant Equation(s)	2
Source of Data	Quantity $BE_{CH4,SWDS,y}$ using the CDM tool "Tool to determine Methane emissions avoided from disposal of dumping waste at a solid waste disposal site"
Data Requirements	W_j and IPCC factors
Collection Procedure	Project Proponent obtains records of waste diverted from landfill to compost facility.
Revision Frequency	Each time Project Proponent uses new composting facility
Comments	To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents

Parameter	W_j
Units	Tons of dry mass
Description	Amount of organic waste type j prevented from disposal, expressed as dry mass
Relevant Section	D.2
Relevant Equation(s)	2
Source of Data	Uncomposted organic waste diverted from landfill
Data Requirements	Tons and type of organic waste prevented from disposal
Collection Procedure	Project Proponent obtains records of waste diverted from landfill to compost facility
Revision Frequency	Each time Project Proponent uses new composting facility
Comments	To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents

Parameter	DOC_j
Units	%
Description	Fraction of waste type j that is degradable organic carbon (by weight)
Relevant Section	D.2
Relevant Equation(s)	2
Source of Data	Characteristics of waste type j
Data Requirements	Fraction of degradable organic carbon(by weight) in the waste type j
Collection Procedure	Project Proponent obtains records of waste diverted from landfill to compost facility.
Revision Frequency	Each time Project Proponent uses new composting facility
Comments	To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents

Parameter	DOC_f
Units	%
Description	Fraction of degradable organic carbon (DOC) that fully decomposes to CO_2.
Relevant Section	D.2

Relevant Equation(s)	2
Source of Data	Characteristics of DOC
Data Requirements	W_j and amount of DOC in compost that fully decomposes to CO_2.
Collection Procedure	Project Proponent obtains records of waste diverted from landfill to compost facility.
Revision Frequency	Each time Project Proponent uses new composting facility
Comments	To be set to 0 when emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents

Parameter	$BE_{\Delta SOC}(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	Annual CO_2 emissions from the change in soil organic C for project parcel i during year y of the baseline scenario. The sign of this component is determined by the baseline trends in SOC, which can be either positive when soil is a net source of CO_2 or negative when it is net sink of CO_2.
Relevant Section	D.2
Relevant Equation(s)	3
Source of Data	Model estimates
Data Requirements	$A(i)$, $\Delta SOC(y,i)$
Collection Procedure	Calculated from equation 3
Revision Frequency	At the start of each crediting period
Comments	

Parameter	$A(i)$
Units	hectares
Description	Size of project parcel i
Relevant Section	D.2, D.3
Relevant Equation(s)	2, 6, 7
Source of Data	Project Proponent records
Data Requirements	Coordinates and area of project parcels
Collection Procedure	Project Proponents will collect and record area of participating project parcels.
Revision Frequency	At the start of each crediting period
Comments	

Parameter	$\Delta SOC(y,i)$
Units	MT C ha^{-1} yr^{-1}
Description	Change in baseline soil organic carbon of project parcel i during year y of the baseline scenario
Relevant Section	D.2
Relevant Equation(s)	3
Source of Data	
Data Requirements	
Collection Procedure	To be calculated using a model that meets the requirements of Section D.1.
Revision Frequency	At the start of each crediting period
Comments	

Parameter	$BE_{N2O}(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	Cumulative baseline Nitrous Oxide emissions from soils of the project parcel i during year y of the baseline scenario, expressed in CO_2-eq.
Relevant Section	D.2
Relevant Equation(s)	4
Source of Data	Model outputs and Project Proponent records
Data Requirements	$A(i)$, $CE_{N2O}(y,i)$
Collection Procedure	Calculated from equation 4
Revision Frequency	At the start of each crediting period
Comments	

Parameter	$CE_{N2O}(y,i)$
Units	MT CO_2-eq ha^{-1} yr^{-1}
Description	Annual N_2O emissions rate from soils of project parcel i during year y of the baseline scenario.
Relevant Section	D.2
Relevant Equation(s)	4
Source of Data	Model input data requirements, multiple sources
Data Requirements	Model specific
Collection Procedure	To be calculated using a model that meets the requirements of Section D.1
Revision Frequency	At the start of each crediting period
Comments	

Parameter	$PE(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	The total sum of the project emissions during year y
Relevant Section	D.3
Relevant Equation(s)	6, 8
Source of Data	Calculated in equation 5
Data Requirements	$PE_{\Delta SOC}(y,i)$, $PE_{N2O}(y,i)$, $PE_{fuel}(y,i)$, $PE_{compost,CH4}(y,i)$
Collection Procedure	Based on calculations from equations 6 and 7
Revision Frequency	Project year (annually)
Comments	

Parameter	$PE_{\Delta SOC}(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	Annual CO_2 emissions from the change in soil organic C for project parcel i during year y of the project
Relevant Section	D.3
Relevant Equation(s)	5, 6
Source of Data	Model outputs and Project Proponent records
Data Requirements	$A(i)$, $\Delta SOC_d(40)$, $\Delta SOC_i(y,i)$

Collection Procedure	Calculated in equation 6
Revision Frequency	Project year (annually)
Comments	The sign of this component is determined by the baseline trends in SOC, which can be either positive when soil is a net source of CO2 or negative when it is net sink of CO_2.

Parameter	$\Delta SOC_d(40)$
Units	MT C ha^{-1} yr^{-1}
Description	Change in carbon from added compost remaining in the soil at year 40
Relevant Section	D.3
Relevant Equation(s)	6
Source of Data	Model input data requirements, multiple sources
Data Requirements	Model specific
Collection Procedure	To be calculated using a model that meets the requirements of Section D.1.
Revision Frequency	Project year (annually)
Comments	

Parameter	$\Delta SOC_i(y,i)$
Units	MT C ha^{-1} yr^{-1}
Description	Annual indirect change in soil carbon due to increases in plant productivity during year.
Relevant Section	D.3
Relevant Equation(s)	6
Source of Data	Model input data requirements, multiple sources
Data Requirements	Model specific
Collection Procedure	To be calculated using a model that meets the requirements of Section D.1
Revision Frequency	Project year (annually)
Comments	

Parameter	$PE_{N2O}(y,i)$
Units	MT CO_2-eq ha^{-1} yr^{-1}
Description	Annual N_2O emissions rate from soils of project parcel i during year y of the project.
Relevant Section	D.3
Relevant Equation(s)	5, 7
Source of Data	Model outputs and Project Proponent records
Data Requirements	$A(i)$, $CE_{N2O}(y,i)$
Collection Procedure	Calculated in equation 7
Revision Frequency	Project year (annually)
Comments	
Parameter	$CE_{N2O}(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	Cumulative Nitrous Oxide emissions from soils of the project parcel i during year y of the project, expressed in CO_2-eq.
Relevant Section	D.3

Relevant Equation(s)	7
Source of Data	Model input data requirements, multiple sources
Data Requirements	Model specific
Collection Procedure	To be calculated using a model that meets the requirements of Section D.1
Revision Frequency	Project year (annually)
Comments	

Parameter	$PE_{fuel}(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	Sum of fuel emissions from transportation to the project parcel and application of the organic material on the land during year y.
Relevant Section	D.3
Relevant Equation(s)	5
Source of Data	Calculated using CDM tool "Project and leakage emissions from road transportation of freight" and CDM tool "Tool to calculate project or leakage CO2 emissions from fossil fuel combustion"
Data Requirements	Quantity and type of fuel consumed and combusted during transportation and application of compost
Collection Procedure	Project Proponent records from transportation and/or compost application receipts
Revision Frequency	Project year when compost is added
Comments	

Parameter	$PE_{compost,CH4}(y,i)$
Units	MT CO_2-eq yr^{-1}
Description	At a year when compost is added, e.g., when $y = 1$, the Methane emissions emitted during composting of the organic material, expressed in CO_2-eq. At all other years, this quantity is to be set to 0. When emission reductions from avoidance of anaerobic emissions are claimed by an entity other than the Project Proponents, this quantity is to be set to 0 at all times to avoid double discounting.
Relevant Section	D.3
Relevant Equation(s)	5
Source of Data	Calculated the most recent emission factor available from the IPCC.
Data Requirements	kg of dry weight organic waste, factor to convert g CH4 to MT CO_2-eq
Collection Procedure	
Revision Frequency	Project year when compost is added
Comments	

Parameter	ER_y
Units	tCO_2-eq yr^{-1}
Description	GHG emissions reductions and/or removals in year y
Relevant Section	D.4
Relevant Equation(s)	8
Source of Data	Calculated in equation 8

Data Requirements	$nrParcels$, $PE(y,i)$, $BE(y,i)$, $CH_4enteric$
Collection Procedure	Based on Project Proponent records, as well as calculations from equations 1 and 5.
Revision Frequency	Project year (annually)
Comments	

Parameter	$nrParcels$
Units	#
Description	Number of project parcels
Relevant Section	D.4
Relevant Equation(s)	8
Source of Data	Project Proponent records
Data Requirements	Parcels participating in the project
Collection Procedure	Counting parcels participating in project
Revision Frequency	For each change in number of project parcel participating- revised before each new crediting period
Comments	

Parameter	$CH_4enteric$
Units	$MTCO_2$-eq yr^{-1}
Description	Enteric emissions associated with an increase in stocking rate over each project parcel.
Relevant Section	D.3, D.4
Relevant Equation(s)	8
Source of Data	Either a value of zero, or the value from cell J13 of the 6.T-XANTE tab of the *ACR Tool for Estimation of Emissions from Livestock Management Projects*, whichever is less.
Data Requirements	Grazing ruminant population, feeding situation (i.e. grazing or not grazing), percentage imported feed vs. grazing, mean daily temperature during winter
Collection Procedure	Project Proponent records
Revision Frequency	Data collected monthly and parameter revised each project year (annually)
Comments	

A.2 Other Project Data Required for Validation

Parameter	$compost$
Units	Multiple
Description	Analysis every time of compost applied
Relevant Section	E
Relevant Equation(s)	
Source of Data	Project Proponent records (from certification or from laboratory test results)
Data Requirements	Carbon concentration, nitrogen concentration, C:N ratio, bulk density, moisture content, pH, phosphorus concentration (optional), source of compost raw

	materials (optional), fate of organic matter under baseline conditions (optional)
Collection Procedure	Project Proponent reports from records
Revision Frequency	Every time compost is applied throughout project
Comments	

Parameter	*soil*
Units	Multiple
Description	Analysis for each stratum representing at least 0-20cm both before and after compost application for baseline and project calculations
Relevant Section	E
Relevant Equation(s)	
Source of Data	Laboratory test results
Data Requirements	Total soil carbon, soil texture, soil bulk density, soil pH
Collection Procedure	Project Proponent collects soil samples submits for analysis
Revision Frequency	Once at the beginning of project and again after the compost application, then at least every 10 years thereafter
Comments	

Parameter	*historical weather*
Units	Multiple (degrees, inches)
Description	Characterizes important weather and climate characteristics for each project
Relevant Section	E
Relevant Equation(s)	
Source of Data	Weather station or other published weather records
Data Requirements	Daily minimum and maximum temperatures, rainfall
Collection Procedure	Project Proponent uses nearest weather station to project or other published weather records (such as Daymet) for use in model
Revision Frequency	Once at the beginning of project to establish a baseline
Comments	

Parameter	*project weather*
Units	Multiple (degrees, inches)
Description	Characterizes important weather and climate characteristics for each project
Relevant Section	E
Relevant Equation(s)	
Source of Data	Weather station or other published weather records used for historical weather
Data Requirements	Daily minimum and maximum temperatures, rainfall
Collection Procedure	Project Proponent uses nearest weather station to project or other published weather records (such as Daymet) for use in model
Revision Frequency	Project year (annually)
Comments	

Parameter	*historical management*
Units	Multiple
Description	Historical grazing practices on Project Proponent’s land

Relevant Section	C
Relevant Equation(s)	
Source of Data	Project Proponent records
Data Requirements	Stocking period (averaged over at least 3 of past 5 years), stocking rate(averaged over at least 3 of past 5 years), incidence of fires
Collection Procedure	Project Proponent records
Revision Frequency	When setting baseline
Comments	

Parameter	*project management*
Units	Multiple
Description	Grazing practices throughout project
Relevant Section	
Relevant Equation(s)	
Source of Data	Project Proponent records
Data Requirements	Project population, stocking period, average stocking rate(averaged over the years), minimum stocking rate, maximum stocking rate, incidence of fires
Collection Procedure	Project Proponent reports from records
Revision Frequency	Project year (annually)
Comments	

Parameter	*Plants and plant communities*
Units	Multiple
Description	Characterizes important plant communities present for each project
Relevant Section	E
Relevant Equation(s)	
Source of Data	Project parcels (Land assessment by a Qualified Expert, consistent with standard NRCS ecological site descriptions)
Data Requirements	Stratification of land, description of plant productivity (species type and forage quality), broad description of plant communities, percentage cover of native plants, indication of any problems with invasive weeds, assessment of fire risk)
Collection Procedure	Land assessment by a Qualified Expert, consistent with standard NRCS ecological site descriptions
Revision Frequency	Once at the beginning of project and at year 2 and year 5 after compost application
Comments	

Parameter	*Compost application*
Units	Multiple
Description	Description of application procedure
Relevant Section	E
Relevant Equation(s)	
Source of Data	
Data Requirements	Application date, machinery used, application method, broadcast rate (tons/ha), rationale for application procedure and reference source (if

	available), receipts of compost purchase, transportation, and application, pictures during application (optional)
Collection Procedure	Collected during compost application
Revision Frequency	Every time compost is applied throughout project
Comments	All data collected as part of monitoring must be archived electronically and be kept at least for two years after the end of the project crediting period.