Draft VCS Module

VMD00XX

CO_2 CAPTURE FROM ACID GAS REMOVAL AT NATURAL GAS PROCESSING PLANTS

Version 1.0

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Sectoral Scope 16: Carbon Capture and Storage

This draft module was developed by Verra with support from BKV Corporation (BKV).

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1 SUMMARY DESCRIPTION

This module calculates project emissions ($PE_{Cap,y}$) and leakage emissions ($LE_{Cap,y}$) from project activities eligible under the most recent version of Verified Carbon Standard (VCS) methodology *VM0049 Carbon Capture and Storage* that result in the diversion of carbon dioxide, separated from raw natural gas flows through acid gas removal and capture processes, towards permanent storage.

This module establishes applicability conditions, defines the baseline scenario and the module boundary to determine relevant greenhouse gas (GHG) sources for quantification, and provides monitoring procedures.

Project emissions ($PE_{Cap,y}$) are calculated in Equation (1).

Leakage emissions ($LE_{Cap,y}$) are calculated in Equation (5).

The project and leakage emissions calculated in this module, together with those calculated in the transport and storage modules, are used in *VM0049* to calculate the net GHG emission reductions ("reductions") from projects using this module.

2 SOURCES

This module is used in combination with the most recent versions of *VM0049* and the following VCS Program modules and tools:

Capture Modules

- *VMD0056 CO_2 Capture from Air (Direct Air Capture)*
- *VMD0059 CO_2 Capture from Bioenergy*

Transport Module

- *VMD0057 CO_2 Transport for CCS Projects*

Storage Module

- *VMD0058 CO_2 Storage in Saline Aquifers and Depleted Hydrocarbon Reservoirs*

Other Modules, Tools, and Requirements

- *VT0010 Emissions from Electricity Consumption and Generation*
- *VT0012 Accounting non-VCS CO_2 in CCS Projects*
- *Geologic Carbon Storage (GCS) Non-Permanence Risk Tool*
- *GCS Requirements*

This module uses the most recent versions of the following Clean Development Mechanism (CDM) tools:

- *TOOL09 Determining the Baseline Efficiency of Thermal or Electric Energy Generation Systems*
- *TOOL10 Tool to Determine the Remaining Lifetime of Equipment*

3 DEFINITIONS

In addition to the definitions set out in the *VCS Program Definitions* and *VM0049*, the following definitions apply to this module.

Acid gas
Hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) contaminants present in raw natural gas streams that are separated from sour natural gas by an acid gas removal unit[1]

Capture materials
The chemicals and media used to capture carbon dioxide. Depending on the technology, this may include capture solvents, solid sorbents, membranes, or catalysts, which may have to be replaced periodically due to loss or degradation over time. Examples include aqueous potassium hydroxide (KOH) and amine supported on activated carbon.

Existing natural gas processing plant
A natural gas processing plant in operation on 1 September 2025[2]

Natural gas processing plant
An industrial facility that processes raw natural gas to produce compressed, pipeline-quality dry natural gas and hydrocarbon by-products[3]

[1] Adapted from the US Environmental Protection Agency (US EPA): eCFR :: 40 CFR 98.238 -- Definitions. Available at: https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-W/section-98.238

[2] Verra announced its intention to develop this module in August 2025.

[3] Adapted from the US EPA's definition of natural gas processing: eCFR :: 40 CFR 98.230 -- Definition of the source category. Available at: https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-W/section-98.230

4 APPLICABILITY CONDITIONS

This module applies to project activities that capture CO_2 separated from raw natural gas streams at natural gas processing plants.

This module is applicable under the following conditions:

1) Project activities include at least one of the following:
    a) The installation and operation of equipment or systems that divert captured CO_2 towards permanent storage at an existing natural gas processing plant
    b) Refurbishment of an existing capture facility, which would otherwise be decommissioned prior to the project start date, at an existing natural gas processing plant
2) Capture occurs using one or a combination of the following processes:
    a) Chemical or physical absorption or adsorption, with liquid solvents or solid sorbents (e.g., amines)
    b) Membrane processes
3) The capture process used in the project activities is designed to regenerate the primary capture fluid or media, such that it is not a one-time use, and a concentrated CO_2 stream is recovered from regeneration and available for subsequent transport (where applicable) and storage.

This module is not applicable under the following condition:

4) Project activities comprise upgrades to existing natural gas processing facilities or changes in operational practices leading to improved capture efficiency.

5 PROCEDURES

5.1 Module Boundary

The module boundary includes at least the existing natural gas processing plant generating the CO_2 emissions captured and diverted for permanent storage by the project. Commonly used equipment and processes include:

- equipment used to generate airflow for the capture process (e.g., fans);
- capture of CO_2 in contactors, beds, or vessels by absorption, adsorption, or other processes;
- regeneration processes to generate a CO_2 stream and recover capture fluid or media;
- conditioning of CO_2 to allow further processing of CO_2 along the carbon capture and storage (CCS) segments (namely transport and storage); and

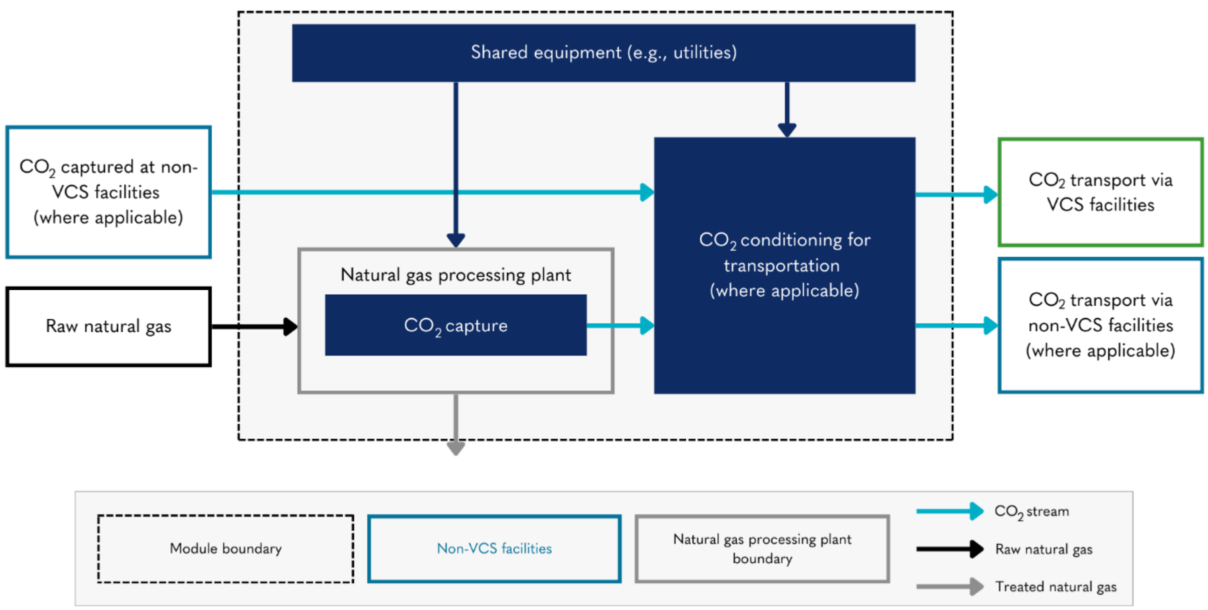
- co-located utilities for the CO_2 capture process (e.g., air separation units, water treatment systems, steam systems).

Section 5 of the most recent version of *VM0049* provides further details on determining the module boundary. The capture facility, ancillary sites, equipment, and relevant project emissions included in the module boundary and quantified using this module must be clearly identified and documented. The project proponent must ensure that equipment is not omitted or double-counted.

In cases where non-VCS[4] CO_2 flows through the project boundary, the most recent version of *VT0012 Accounting non-VCS CO_2 in CCS Projects* must be used to calculate the proportion of project emissions and leakage emissions associated with that non-VCS CO_2.

The boundary for this module is presented in Figure 1.

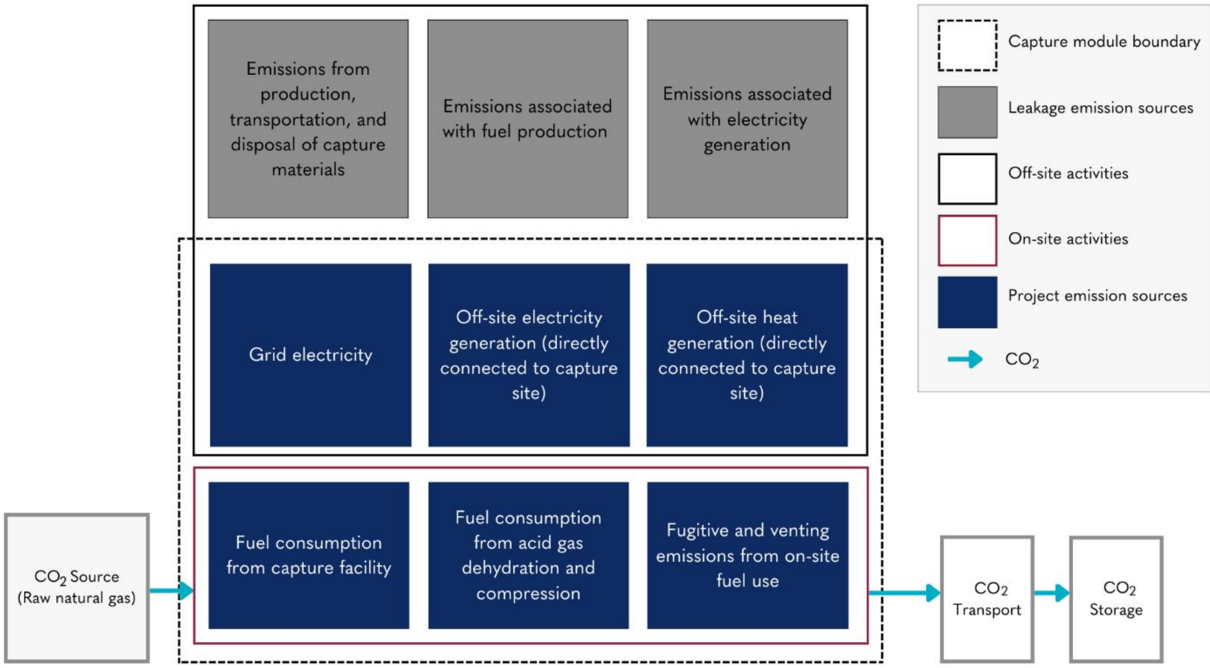
Figure 1. Module boundary



Sources of GHG emissions within the module boundary are depicted in Figure 2.

[4] Non-VCS CO_2 is defined in *VT0012* as "Carbon dioxide that flows through a carbon capture and storage (CCS) project boundary and does not generate credits under the VCS Program."

Figure 2. Emission sources within the module boundary



The greenhouse gases included in and excluded from the module boundary are depicted in Table 1.

Table 1. GHG sources and sinks accounted for as baseline, project, and leakage emissions

Source/Sink		Type	Gas	Included?	Justification/Explanation
Baseline	Electricity consumption from capture facility	Source	CO_2	No	The operation of the capture facility is consistent between the baseline and project scenarios and therefore the emissions are equivalent.
			CH_4		
			N_2O		
			Other		
	Fuel consumption from capture facility	Source	CO_2	No	The operation of the capture facility is consistent between the baseline and project scenarios and therefore the emissions are equivalent.
			CH_4		
			N_2O		
			Other		
	Fugitive and venting emissions from on-site fuel use	Source	CO_2	No	The components of the natural gas service present in the baseline are also present in the project and therefore the emissions are equivalent.
			CH_4		
			N_2O		
			Other		

	Fuel combustion from flaring or incineration of acid gas	Source	CO_2	No	Excluded for conservativeness[5]
			CH_4		
			N_2O		
			Other		
	Production, transportation, and disposal of capture materials	Source	CO_2	No	The operation of the capture facility is consistent between the baseline and project scenarios and therefore the emissions are equivalent.
			CH_4		
			N_2O		
			Other		
Project	Electricity consumption from capture facility	Source	CO_2	No	The operation of the capture facility is consistent between the baseline and project scenarios and therefore the emissions are equivalent.
			CH_4		
			N_2O		
			Other		
	Fuel consumption from capture facility	Source	CO_2	No	The operation of the capture facility is consistent between the baseline and project scenarios and therefore the emissions are equivalent.
			CH_4		
			N_2O		
			Other		
	Fugitive and venting emissions from on-site fuel use for components of gas service not present in baseline	Source	CO_2	No	De minimis
			CH_4	Yes	Emission source
			N_2O	No	De minimis
			Other	No	No other greenhouse gases
	Electricity consumption for acid gas conditioning processes	Source	CO_2	Yes	Emission source
			CH_4	No	De minimis
			N_2O	No	De minimis
			Other	No	No other greenhouse gases
	Fuel consumption for acid gas conditioning processes	Source	CO_2	Yes	Emission source
			CH_4	Yes	Emission source
			N_2O	Yes	Emission source
			Other	No	No other greenhouse gases

[5] Project proponents seeking credit for emissions avoidance from this source may apply a second methodology relevant to that activity, following Section 3.6.1 of the *VCS Standard, v4.7.*

Leakage	Fuel consumption for acid gas conditioning processes	Source	CO_2	Yes	Emission source
			CH_4	Yes	Emission source
			N_2O	No	De minimis
			Other	No	No other greenhouse gases
	Production, transportation, and disposal of capture materials	Source	CO_2	No	The operation of the capture facility is consistent between the baseline and project scenarios and therefore the emissions are equivalent.
			CH_4		
			N_2O		
			Other		

5.2 Baseline Scenario

Project proponents must accurately determine the activities and GHG emissions that would have occurred in the absence of the project activity. The baseline scenario identified through the process outlined below is used to inform the assessment of project additionality in Section 7 of *VM0049*.

Project proponents must assess the following alternative scenarios relevant to the project activity:

Baseline B1: CO_2 is vented, flared, or incinerated at an existing natural gas processing plant. This alternative scenario must be considered where either of the following applies:

a) No equipment or systems that divert captured CO_2 towards permanent storage were operating at the existing natural gas processing plant before the project start date.

b) A capture facility was installed at an existing natural gas processing plant and reached its end of life before the project start date. The most recent version of CDM *TOOL10 Tool to Determine the Remaining Lifetime of Equipment* must be applied to demonstrate that the remaining lifetime of the capture facility was zero before the project start date.

Baseline B2: CO_2 is captured and diverted towards permanent storage, and/or utilization in products or processes, at historical levels from an existing natural gas processing plant.

Baseline B3: The proposed project activity occurs without being registered with a GHG program.

To identify the baseline scenario from the alternative scenarios, project proponents must:

1) remove alternative scenarios that do not comply with mandatory laws and regulations in the jurisdiction where the project is located. Alternative scenarios must be compatible with all applicable laws and regulations, including those that have objectives other than GHG emission reductions and/or carbon dioxide removals (e.g., for local air pollution control). Policies that do not have legally binding status must not be considered.

2) demonstrate that the proposed project activity faces a financial barrier following Section 7 of *VM0049*.

The remaining alternative is the baseline scenario and the following applies:

- Project activities that involve the installation and operation of a new equipment or systems to divert CO_2 towards permanent storge are only eligible where the baseline scenario is B1.
- Project activities that involve the refurbishment of an existing capture facility are only eligible where the baseline scenario is B1.
- Project activities that involve the expansion of existing capture capacity are only eligible where the baseline scenario is B2. The amount of CO_2 that would have been captured, and stored or utilized in the absence of the project activity must be accounted for as non-VCS CO_2 in each segment, according to the procedures outlined in the most recent version of *VT0012*.

5.3 Quantification of Project Emissions

The following sections provide guidance for determining the emissions that result from project activities (i.e., $PE_{Cap,y}$). Project emissions are calculated as per Equation (1).

$$PE_{Cap,y} = PE_{Comb\_Fuel,y} + PE_{Fuel\_FV,y} + PE_{Elec,y} - PE_{nonVCS\ CO2,y} \tag{1}$$

Where:

$PE_{Cap,y}$	=	Project emissions from capture in year *y* (t CO_2e)
$PE_{Comb\_Fuel,y}$	=	Project emissions from fuel combustion to operate acid gas dehydration, compression, and conditioning processes in year *y* (t CO_2e)
$PE_{Fuel\_FV,y}$	=	Fugitive and venting from on-site natural gas use to operate equipment not present in the baseline in year *y* (t CO_2e)
$PE_{Elec,y}$	=	Project emissions from electricity consumption to operate equipment not present in the baseline in year *y*, calculated using VCS tool *VT0010 Emissions from Electricity Consumption and Generation* (t CO_2e)
$PE_{nonVCS\ CO2,y}$	=	Project emissions from processes and equipment related to non-VCS sources in year *y* determined using the most recent version of *VT0012*; equal to zero for projects with no non-VCS CO_2 (t CO_2e)

5.3.1 Project Emissions from Fuel Combustion

Project emissions from fossil fuel combustion for acid gas dehydration and conditioning and compression processes are calculated in Equation (2).

$$PE_{Comb\_Fuel,y} = \sum_{d} (Q_{Fuel,d,y} \times EF_{Fuel,CO2,d}) + (Q_{Fuel,d,y} \times EF_{Fuel,CH4,d} \times GWP_{CH4}) + (Q_{Fuel,d,y} \times EF_{Fuel,N2O,d} \times GWP_{N2O}) \tag{2}$$

Where:

$PE_{Comb\_Fuel,y}$ = Project emissions from fuel combustion to operate acid gas dehydration, compression, and conditioning processes in year y (t CO_2e)

$Q_{Fuel,d,y}$ = Quantity of fuel type d used to operate on-site and/or third-party (for off-site heat/steam supply) equipment in year y (m^3 or kg or GJ)

$EF_{Fuel,CO2,d}$ = Carbon dioxide emission factor for combustion of fuel d (t CO_2/m^3 or t CO_2/kg or t CO_2/GJ); equal to zero for fuels derived from sustainable biomass

$EF_{Fuel,CH4,d}$ = Methane emission factor for combustion of fuel d (t CH_4/m^3 or t CH_4/kg or t CH_4/GJ)

$EF_{Fuel,N2O,d}$ = Nitrous oxide emission factor for combustion of fuel d (t N_2O/m^3 or t N_2O/kg or t N_2O/GJ)

GWP_{CH4} = Global warming potential for methane (t CO_2e/t CH_4)

GWP_{N2O} = Global warming potential for nitrous oxide (t CO_2e/t N_2O)

Where an emission factor that considers only combustion emissions is not available for a given fuel, a combined emission factor for both combustion and upstream emissions may be used as $EF_{Fuel,d}$ in Equation (2).

Off-site Fuel Consumption

The quantity of power and/or heat supplied from a directly connected off-site facility is determined using Equation (3).

$$Q_{Fuel,d,y} = Q_{Cogen,d,y} \times \frac{\left({Heat_{Capture,y}}/{\eta_{Heat,y}} + {Electricity_{Capture,y}}/{\eta_{Elec,y}} \right)}{\left({Heat_{Cogen,y}}/{\eta_{Heat,y}} + {Electricity_{Cogen,y}}/{\eta_{Elec,y}} \right)} \tag{3}$$

Where:

$Q_{Fuel,d,y}$ = Quantity of fuel type d used to operate on-site and/or third-party (for off-site heat/steam supply) equipment in year y (m^3 or kg or GJ)

$Q_{Cogen,d,y}$ = Quantity of fuel type d used by the cogeneration unit to generate electricity and/or heat in year y (m^3 or kg or GJ)

$Heat_{Capture,y}$ = Quantity of useful thermal energy supplied to the capture facility by the cogeneration unit in year y; equal to zero where only electricity is supplied to the capture facility (MWh)

$Electricity_{Capture,y}$ = Quantity of electricity supplied to the capture facility by the cogeneration unit in year y; equal to zero where only heat is supplied to the capture facility (MWh)

$Heat_{Cogen,y}$ = Total quantity of useful thermal energy produced by the cogeneration unit in year y (MWh)

$Electricity_{Cogen,y}$ = Total quantity of electricity produced by the cogeneration unit in year y (MWh)

$\eta_{Heat,y}$ = Efficiency of thermal energy production from cogeneration unit in year y determined using the most recent version of CDM *TOOL09*

		Determining the Baseline Efficiency of Thermal or Electric Energy Generation Systems
$\eta_{Elec,y}$	=	Efficiency of electricity production from cogeneration unit in year *y* determined using the most recent version of CDM *TOOL09*

Waste Heat

Project emissions from the consumption of waste heat may be assumed to be zero for heat sources that meet the definition of waste heat in *VM0049*. Emissions associated with the generation of heat that does not meet the definition of waste heat must be accounted for in Equations (2) or (3) as appropriate.

5.3.2 Fugitive and Venting Emissions from On-Site Fuel Use

Projects that use natural gas on-site must quantify fugitive and venting emissions from components that are not present in the baseline, using Equation (4).

$$PE_{Fuel\_FV,y} = \left(\sum_n Count_{n,y} \times EF_n \times T_{n,y} \times 0.001 + \sum_m V_m\right) \times GWP_{CH_4} \quad (4)$$

Where:

$PE_{Fuel\_FV,y}$	=	Fugitive and venting from on-site natural gas use associated with project activities in year *y* (t CO_2e)
$Count_{n,y}$	=	Total number of components *n* in use at the facility during year *y* that are not present in the baseline (unitless)
EF_n	=	Emission factor of fugitive emissions for component *n* (kg CH_4/hr/unit)
$T_{n,y}$	=	Time for which component *n* is pressurized in year *y* (hr)
V_m	=	Vented methane emissions for venting event *m* (t CH_4/event)
0.001	=	Conversion from kilograms to tonnes

5.4 Quantification of Leakage

The leakage emissions from project activities are calculated as per Equation (5).

$$LE_{Cap,y} = LE_{Fuel,y} - LE_{nonVCS\ CO2,y} \quad (5)$$

Where:

$LE_{Cap,y}$	=	Leakage emissions from capture in year *y* (t CO_2e)
$LE_{Elec,y}$	=	Leakage emissions from electricity consumption to operate equipment in not present in the baseline, in year *y* (t CO_2e)
$LE_{nonVCS\ CO2,y}$	=	Leakage emissions from processes and equipment related to non-VCS sources in year *y* determined using the most recent version of *VT0012*; equal to zero for projects with no non-VCS CO_2 (t CO_2e)

5.4.1 Leakage Emissions from Fuel Consumption ($LE_{Fuel,y}$)

Upstream emissions related to fossil fuel consumption for acid gas dehydration, compression, and conditioning processes are calculated using Equation (6).

$$LE_{Fuel,y} = \sum_d (Q_{Fuel,d,y} \times EF_{Upstream\_Fuel,d}) \tag{6}$$

Where:

$LE_{Fuel,y}$	=	Leakage emissions from fuel combustion to operate acid gas dehydration, compression, and conditioning processes in year *y* (t CO_2e)
$Q_{Fuel,d,y}$	=	Quantity of fuel type *d* used to operate on-site and/or third-party (for off-site heat/steam supply) equipment not present in the baseline, in year *y* (m^3 or kg or GJ)
$EF_{Upstream\_Fuel,d}$	=	Emission factor for upstream sources related to fuel type *d* used in the module boundary (t CO_2e/m^3 or t CO_2e/kg or t CO_2e/GJ)

Where power and heat are supplied from an off-site facility, $Q_{Fuel,d,y}$ must be determined as a proportion of the total fuel used to generate the total electricity and heat at the directly connected facility, using Equation (3).

Where a combined emission factor considering both combustion ($EF_{Fuel,d}$) and upstream emissions ($EF_{Upstream\_Fuel,d}$) for a given fuel is used in Equation (2), Equation (6) is not required for that fuel.

5.5 Uncertainty

The primary sources of uncertainty identified for the project activities covered in this module are measurement error related to fuel combustion and the production of capture materials. All other potential sources of uncertainty are either considered de minimis or accounted for in the conservativeness of the default factors.

Uncertainty of measurement error related to project emissions from fuel combustion for capture activities is considered de minimis where the metering equipment used for determining fuel volumes ($Q_{Fuel,d,y}$) uses a custody transfer meter or fiscal metering for the transaction.

Uncertainty of measurement error from leakage emissions from the production of capture materials is considered de minimis where the magnitude of the leakage emissions is less than 2% of the net reduction or removal benefit of the project.

Proponents whose projects do not meet the above conditions for a source of uncertainty must include that source of uncertainty in their uncertainty assessment as described in Section 8.5 of *VM0049*.

6 DATA AND PARAMETERS

Additional data and parameters are defined in *VM0049* and related tools (VCS and CDM) as applicable.

6.1 Data and Parameters Available at Validation

Data/Parameter	GWP_{CH4}
Data unit	t CO_2e/t CH_4
Description	Global warming potential for methane
Equations	(2), (4)
Source of data	Version of IPCC Assessment Report required by *VCS Standard*
Value applied	See the most recent version of the *VCS Standard*.
Justification of choice of data or description of measurement methods and procedures applied	Required by the *VCS Standard*
Purpose of data	Calculation of project emissions
Comments	None

Data/Parameter	GWP_{N2O}
Data unit	t CO_2e/t N_2O
Description	Global warming potential for nitrous oxide
Equations	(2)
Source of data	Version of IPCC Assessment Report required by *VCS Standard*
Value applied	See the most recent version of the *VCS Standard*.
Justification of choice of data or description of measurement methods and procedures applied	Required by the *VCS Standard*
Purpose of data	Calculation of project emissions
Comments	None

6.2 Data and Parameters Monitored

Data/Parameter	$Q_{Fuel,d,y}$
Data unit	m^3 or kg or GJ
Description	Quantity of fuel type *d* used to operate on-site and/or third-party (for off-site heat/steam supply) equipment not present in the baseline, in year *y*
Equations	(2), (6)
Source of data	Fuel receipts/invoices or flow meter readings Where the project proponent does not have access to fuel receipts/invoices and flow meter readings, equipment specifications and conservative runtime information may be used to estimate fuel consumption.
Description of measurement methods and procedures to be applied	Measured from flow meters or calculated from fuel receipts/invoices. Otherwise, equipment specifications and conservative runtime information may be used to estimate fuel consumption.
Frequency of monitoring/recording	Continuous
QA/QC procedures to be applied	Measuring equipment (e.g., flow meters, weighing scale) must operate within the manufacturer's specified operating conditions and must be routinely calibrated, inspected, and maintained according to manufacturer specifications.
Purpose of data	Calculation of project and leakage emissions
Calculation method	Monthly fuel consumption is determined by summing the quantities from calibrated device readings or fuel receipts/invoices.
Comments	None

Data/Parameter	$EF_{Fuel,CO2,d}$ $EF_{Fuel,CH4,d}$ $EF_{Fuel,N20,d}$
Data unit	t CO_2/m^3 or t CO_2/kg or t CO_2/GJ t CH_4/m^3 or t CH_4/kg or t CH_4/GJ t N_2O/m^3 or t N_2O/kg or t N_2O/GJ
Description	Carbon dioxide emission factor for combustion of fuel *d* Methane emission factor for combustion of fuel *d* N_2O emission factor for combustion of fuel *d*
Equations	(2)

Source of data	The following data sources may be used: 1) Emission factor from *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 2, Chapter 2 Stationary Combustion, Table 2.2[6] 2) Emission factors published by US EPA (2023)[7] or similar source 3) Data provided by the fuel supplier 4) Determination of combustion emissions using direct measurement methods, where the measurement approach is consistent with approved guidance from a recognized regulatory authority, such as the US EPA's Electronic Code of Federal Regulations, Title 40, Part 98, Subpart W, § 40 CFR Part 98, Subpart W §98.233(z)[8]
Description of measurement methods and procedures to be applied	Use the most recent data published by the above sources when reporting project emissions.
Frequency of monitoring/recording	Annual
QA/QC procedures to be applied	N/A
Purpose of data	Calculation of project emissions
Calculation method	N/A
Comments	$EF_{Fuel,CO2,d}$ is equal to zero for fuels derived from sustainable biomass.

Data/Parameter	$Q_{Cogen,d,y}$
Data unit	m^3 or kg or GJ
Description	Quantity of fuel type *d* used by the cogeneration unit to generate electricity and/or heat in year *y*
Equations	(3)
Source of data	Fuel receipts/invoices or flow meter readings, as applicable
Description of measurement methods and procedures to be applied	Measured from flow meters or calculated from fuel receipts or invoices

[6] Available at: https://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_2_Ch2_Stationary_Combustion.pdf

[7] Available at: https://www.epa.gov/climateleadership/ghg-emission-factors-hub

[8] Available at: https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-W#p-98.233(z)

Frequency of monitoring/recording	Continuous or for every invoice, aggregated annually
QA/QC procedures to be applied	Measuring equipment (e.g., flow meters, weighing scale) must operate within the manufacturer's specified operating conditions and must be routinely calibrated, inspected, and maintained according to manufacturer specifications.
Purpose of data	Calculation of project emissions
Calculation method	Monthly fuel consumption is determined by summing the quantities from calibrated device readings or fuel receipts/invoices.
Comments	Invoices and/or contracts with the third party must be in place to allow proper data collection.

Data/Parameter	$Heat_{Capture,y}$
Data unit	MWh
Description	Quantity of useful thermal energy supplied to the capture facility by the cogeneration unit in year *y*
Equations	(3)
Source of data	Utility receipts/invoices or metered data for heat usage
Description of measurement methods and procedures to be applied	Measured from calorimeters or calculated from receipts/invoices, considering energy content in steam and condensate return as applicable based on steam properties
Frequency of monitoring/recording	Continuous, aggregated annually
QA/QC procedures to be applied	The calorimeter must be routinely calibrated, inspected, and maintained according to manufacturer specifications.
Purpose of data	Calculation of project emissions
Calculation method	Monthly supplied heat is determined by summing the quantities from calibrated device readings or fuel receipts/invoices.
Comments	Invoices and/or contracts with the third party must be in place to allow proper data collection.

Data/Parameter	$Electricity_{Capture,y}$
Data unit	MWh
Description	Quantity of electricity supplied to the capture facility by the cogeneration unit in year *y*

Equations	(3)
Source of data	Utility receipts/invoices or metered data for electricity use
Description of measurement methods and procedures to be applied	Measured from electricity meters or calculated from receipts/invoices
Frequency of monitoring/recording	Continuous, aggregated annually
QA/QC procedures to be applied	Electricity meters must be routinely calibrated, inspected, and maintained according to manufacturer specifications.
Purpose of data	Calculation of project emissions
Calculation method	Monthly supplied electricity is determined by summing the quantities from calibrated device readings or fuel receipts/invoices.
Comments	Invoices and/or contracts with the third party must be in place to allow proper data collection. Value is equal to zero where only heat is supplied to the capture facility.

Data/Parameter	$Heat_{Cogen,y}$
Data unit	MWh
Description	Total quantity of useful thermal energy produced by the cogeneration unit in year *y*
Equations	(3)
Source of data	Utility receipts/invoices or metered data for heat produced
Description of measurement methods and procedures to be applied	Direct measurement of steam flows (or other heat transfer fluid) and characteristics at the cogeneration facility, considering energy content in steam and condensate return
Frequency of monitoring/recording	Continuous, aggregated monthly
QA/QC procedures to be applied	Calorimeters must be routinely calibrated, inspected, and maintained according to manufacturer specifications.
Purpose of data	Calculation of project emissions
Calculation method	Monthly heat production is determined by summing the quantities from calibrated device readings.
Comments	Invoices and/or contracts with the third party must be in place to allow proper data collection.

Data/Parameter	$Electricity_{Cogen,y}$
Data unit	MWh
Description	Total quantity of electricity produced by the cogeneration unit in year *y*
Equations	(3)
Source of data	Utility receipts/invoices or metered data for off-grid use
Description of measurement methods and procedures to be applied	Measured from electricity meters or calculated from receipts or invoices
Frequency of monitoring/recording	Continuous, aggregated monthly
QA/QC procedures to be applied	Electricity meters must be routinely calibrated, inspected, and maintained according to manufacturer specifications.
Purpose of data	Calculation of project emissions
Calculation method	Monthly electricity production is determined by summing the quantities from calibrated device readings.
Comments	Invoices and/or contracts with the third party must be in place to allow proper data collection.

Data/Parameter	$Count_{n,y}$
Data unit	unitless
Description	Total number of components *n* in use at the facility during year *y* that are not present in the baseline (unitless)
Equations	(4)
Source of data	Records of capture facility (e.g., pipe and instrument drawing, parts lists)
Description of measurement methods and procedures to be applied	Quantification is based on component counts and respective emission factors. Fugitive emissions are quantified following the approach in the US EPA's Electronic Code of Federal Regulations, Title 40, Part 98, Subpart W, § 98.233 (r).[9] Examples of emission sources for fugitive emissions include components such as valves, pipe fittings/connectors, open-ended pipes, pressure relief valves, flanges, meters, and instruments.

[9] Available at: https://www.ecfr.gov/current/title-40/part-98/subpart-W#p-98.233(r)

Frequency of monitoring/recording	Annual
QA/QC procedures to be applied	Use the most recent data available from the capture facility.
Purpose of data	Calculation of project emissions
Calculation method	Annually count all *n* components in use at the facility from facility records (e.g., drawings, parts lists).
Comments	Potential sources for fugitive emissions in the capture facility include components such as valves, pipe fittings/connectors, open-ended pipes, pressure relief valves, flanges, meters, and instruments.

Data/Parameter	$T_{n,y}$
Data unit	hours
Description	Time for which component *n* is pressurized in year *y*
Equations	(4)
Source of data	Records of capture facility (e.g., control systems, recorded operational data)
Description of measurement methods and procedures to be applied	Option 1: Data from capture facility records Option 2: A default of 8760 hours, based on the assumption that components remain pressurized at all times throughout the year
Frequency of monitoring/recording	Annual
QA/QC procedures to be applied	Use the most recent data available from the capture facility.
Purpose of data	Calculation of project emissions
Calculation method	Use annual operational records to determine $T_{n,y}$ of each component *n* or use default value.
Comments	None

Data/Parameter	V_m
Data unit	t CH_4/event
Description	Vented CH_4 emissions for venting event *m*
Equations	(4)
Source of data	Data from the capture facility

Description of measurement methods and procedures to be applied	Option 1: Direct measurement of venting Option 2: Estimated based on isolated volumes of pipes and equipment Option 3: Estimated based on non-isolated volumes of pipes and equipment. The project proponent must determine the quantity of vented CH_4 by transient flow rate calculations for compressible fluids appropriate for the expected evolving conditions in the pipeline or component, based on the approximate geometry of the escaping flow and pipelines/components connected to the venting.
Frequency of monitoring/recording	Annual
QA/QC procedures to be applied	Cross-checked based on energy balance related to metered fuel use
Purpose of data	Calculation of project emissions
Calculation method	Determine V_m by direct measurement or estimate using isolated or non-isolated volumes of pipes and equipment. Use appropriate transient flow rate calculations for CH_4 venting events.
Comments	None

Data/Parameter	EF_n
Data unit	kg CH_4/hr/unit
Description	Emission factor of fugitive emissions for component n
Equations	(4)
Source of data	Emission factor derived from subpart W of US EPA. 2023. *Mandatory GHG Reporting Program*[10] or equivalent nationally appropriate regulations
Description of measurement methods and procedures to be applied	Use the most recent data published by the above sources at the time of reporting project emissions.
Frequency of monitoring/recording	Annual
QA/QC procedures to be applied	N/A
Purpose of data	Calculation of project emissions
Calculation method	N/A

[10] For more information see: https://www.epa.gov/ghgreporting/subpart-w-petroleum-and-natural-gas-systems

Comments	None

Data/Parameter	$EF_{Upstream\_Fuel,d}$
Data unit	t CO_2e/m^3 or t CO_2e/kg or t CO_2e/GJ
Description	Emission factor for upstream sources related to fuel type *d* used in the module boundary
Equations	(6)
Source of data	1) An LCA conducted by a qualified third party in accordance with the most recent versions of ISO 14064 and 14067, that uses either primary or published and peer-reviewed data[11] 2) A compliance market-approved tool (e.g., CA-GREET,[12] GHGenius[13]) 3) Emission factors published in peer-reviewed literature[14] representative of the fuels used in plant operation both temporally and geographically 4) Data provided by the fuel supplier or manufacturer where the data used are consistent with that reported to a regulatory body
Description of measurement methods and procedures to be applied	Use the most recent data published by the above sources when reporting project emissions.
Frequency of monitoring/recording	Annual
QA/QC procedures to be applied	Where peer-reviewed literature is used, it must have been published within a year of reporting project emissions and must be temporally and geographically representative of the capture facility.
Purpose of data	Calculation of project emissions
Calculation method	N/A
Comments	None

[11] State or national government data on a fuel's carbon intensity are also acceptable sources of data for determining emission factors for fuels used by the project.

[12] The Greenhouse Gases, Regulated Emissions and Energy use in Technologies (GREET) model. Available at: https://greet.es.anl.gov/

[13] Model for Life Cycle Assessment of Transportation Fuels. Available at: https://www.ghgenius.ca/

[14] Peer-reviewed literature must be indexed in the Web of Science: Science Citation Index (SCI; available at https://mjl.clarivate.com), as specified in the *VCS Methodology Requirements*.

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DOCUMENT HISTORY

Version	Date	Comment
v1.0 (draft)	29 September 2025	Public consultation version