American Carbon Registry
AT WINROCK INTERNATIONAL

METHODOLOGY FOR THE QUANTIFICATION, MONITORING, REPORTING AND VERIFICATION OF GREENHOUSE GAS EMISSIONS REDUCTIONS AND REMOVALS FROM

CARBON CAPTURE AND STORAGE PROJECTS

VERSION 2.0

September 2022

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American Carbon Registry®

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ABOUT AMERICAN CARBON REGISTRY® (ACR)

A leading carbon offset program founded in 1996 as the first private voluntary GHG registry in the world, ACR operates in the voluntary and regulated carbon markets. ACR has unparalleled experience in the development of environmentally rigorous, science-based offset methodologies as well as operational experience in the oversight of offset project verification, registration, offset issuance and retirement reporting through its online registry system.

ACKNOWLEDGEMENTS

This methodology was modified by ACR based on a previous version originally developed with Blue Strategies. The methodology is being updated through ACR's public consultation and scientific peer review processes.

ACRONYMS AND DEFINITIONS

If not explicitly defined here, the current definitions in the most recent version of the American Carbon Registry (ACR) Standard apply.

TERM	ACRONYM (if applicable)	DEFINITION
Bioenergy with Carbon Capture and Storage	BECCS	Energy generation through combustion of sustainable biomass with capture and sequestration of associated GHG emissions
Biomass Carbon Removal and Storage	BiCRS	CO_2 removal from the atmosphere through sustainable biomass and permanent sequestration in geologic reservoirs or long-lived products.
Carbon Capture and Storage	CCS	Capture, transport, and permanent storage of CO_2 in geologic reservoirs.
Carbon Dioxide	CO_2	Greenhouse gas and the primary gas to be geologically sequestered. Increased levels of CO_2 have been measured in the atmosphere and attributed to burning of fossil fuels and other industrial processes and the interruption of natural sinks' ability to remove and store CO_2.
Carbon Dioxide Removal	CDR	General term used for removal of CO_2 directly from the atmosphere through biological or technological means.
Carbon dioxide equivalent	CO_2e	CO_2e is a metric to compare other GHGs based on their GWP relative to CO_2 over the same timeframe. The IPCC publishes GWP values for converting all GHGs to a CO_2e basis (see "Global Warming Potential").

TERM	ACRONYM (if applicable)	DEFINITION
Carbon offset credit	Offset	A carbon offset is a reduction in emissions of GHG made to compensate for or to offset an emission of GHG made elsewhere (one offset = 1 Metric Ton CO_2e).
Direct Air Capture	DAC	Technological method for removal of CO_2 directly from the atmosphere.
Enhanced Oil Recovery	EOR	The practice of extracting oil from a reservoir that has already undergone primary and secondary recovery. This can be performed with the injection of CO_2 which increases reservoir pressure and can lower viscosity when gas becomes dissolved in oil. For this methodology, CO_2 injected into a producing oil reservoir is considered EOR.
Global Warming Potential	GWP	Global warming potential is a relative scale translating the global warming impact of any GHG into its CO_2e over the same timeframe. This methodology references the 100-year GWPs consistent with the *ACR Standard*.
Greenhouse Gas	GHG	A natural or anthropogenic gas that absorbs and emits thermal energy, causing atmospheric heating. The primary greenhouse gases are carbon dioxide (CO_2), methane (CH_4), water vapor (H_2O), nitrous oxide (N_2O), and ozone (O_3).
Methane	CH_4	The primary component in "natural gas", can be biogenic (released from natural processes, livestock and agriculture, and anerobic breakdown of biomass) or thermogenic (released during production and transportation of fossil fuels).

TERM	ACRONYM (if applicable)	DEFINITION
Metric ton	MT	The metric unit of measurement for one carbon offset. 1 MT = 2,204.62 pounds or 1.10 US tons.
Monitoring, Reporting, and Verification	MRV	Term which encompasses all activities undertaken to measure, report, and verify emissions and atmospheric leakage for a project.
Nitrous oxide	N_2O	Sources of N_2O include agriculture, fossil fuel combustion, wastewater management, and industrial processes.
Sources, Sinks, and Reservoirs	SSRs	Sources: Any process that releases carbon into the atmosphere is known as a carbon source. Sinks: A natural or artificial reservoir that accumulates and stores some carbon-containing chemical compound for an indefinite period. Reservoirs: A pool of carbon that has the potential to accumulate or lose carbon over time. Generally applicable in the land use sector (aboveground biomass, belowground biomass, litter, dead wood, soil organic carbon, and wood products).
Sustainable Biomass		Forestry - slash or waste from forest and shrub/chaparral management and sawmill residue. Agriculture - crop residue, manure, and energy crops cultivated on marginal or degraded land. Waste - municipal, landfill gas, and wastewater.

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1 BACKGROUND AND APPLICABILITY

1.1 SUMMARY AND DESCRIPTION OF METHODOLOGY

Carbon capture and storage (CCS), which is often also called carbon capture and sequestration, is a technology-based solution for addressing global climate change and generally consists of three component processes.

- Separation and capture of either carbon dioxide (CO_2) molecules as emissions from industrial processes before they enter the atmosphere or CO_2 already residing in the atmosphere, where the latter such process is called carbon dioxide removal (CDR).
- Compression and transport of the captured CO_2.
- Safe, permanent storage of the CO_2 in deep underground geologic formations.

This Methodology provides the quantification and accounting frameworks, including eligibility and monitoring requirements, for the creation of carbon offset credits from the CO_2 removals and emissions reductions resulting from eligible projects that capture, transport, and geologically store CO_2, where eligible CCS project components are shown in Table 1. The Methodology is intended to be used as an incentive within the relevant industries to increase these activities and utilizes a flexible additionality framework which is based on either a performance standard or ACR's three-prong additionality test, as stipulated in Section 3. The Methodology is originally based on the accounting framework developed by the Center for Climate and Energy Solutions.[1]

[1] A Greenhouse Gas Accounting Framework for Carbon Capture and Storage Projects, Center for Climate and Energy Solutions, February 2012

1.2 ELIGIBILITY CONDITIONS

Eligible project sources, forms of transport, and sequestration reservoirs are shown below, this list below is not inclusive, additional projects may be determined to be eligible through consultation with ACR.

Table 1: Eligible CCS Project Components[2]

CCS PROJECT COMPONENT	ELIGIBLE PROJECT ACTIVITIES
CAPTURE	Emissions from industrial processes including but not limited to cement production, iron/steel/aluminum production, hydrogen production, and electrical power generation
	Emissions from sustainable biomass sources including but not limited to ethanol production, woody biomass pelletization, and biogenic power production[3]
	Direct air capture of CO_2 (DAC)
TRANSPORT	Pipelines, rail lines, roads, or maritime ships
STORAGE	Saline formations and depleted or producing oil and gas onshore or offshore reservoirs[4] (including enhanced oil recovery [EOR][5])

[2] ACR does not include the potential negative carbon accounting from bioenergy carbon and storage (BECCS) as an eligible CCS project component in Version 2.0 of this Methodology, where ACR may include such negative accounting as an eligible component in future versions. Projects involving biomass should engage with ACR to determine eligibility.

[3] For this methodology, Sustainable Biomass is defined as forestry slash and waste from forest and shrub/chaparral management and sawmill residue; agriculture including crop residue, manure, and energy crops cultivated on marginal or degraded land; and waste including municipal, landfill gas, and wastewater.

[4] ACR does not include potential carbon mineralization or enhanced weathering as an eligible CDR project activities in Version 2.0 of this Methodology, ACR may include in future versions.

[5] EOR projects are eligible. If EOR projects transition from EOR or oil field disposal wells (USEPA Class II) to CO_2 sequestration only wells (USEPA Class VI) after project registration, those projects will remain eligible through the end of the current Crediting Period. The eligibility of the project during future Crediting Periods will include an assessment of whether the transition rules require conversion of the project's Class II wells to remain eligible. A description of EOR is included in Appendix A.

1.3 APPLICABILITY CONDITIONS

In addition to satisfying the ACR program eligibility requirements as found in the latest *ACR Standard*, project activities must satisfy the following conditions for this Methodology to be applicable:

I. Be located in the United States, U.S. Territories, Canada, or Mexico. Other locations will be included in subsequent updates.
II. Permanently sequester CO_2 in saline, depleted, or active oil and gas reservoirs.
III. Be a new CCS project or a project addition which will increase project capacity.
IV. For Version 2.0 of the methodology only - projects that are inactive at the time of publishing may list within 12 months of publication. This does not apply to projects that are inactive due to regulatory incompliance. Compliance must be demonstrated prior to listing.
V. Utilize Class II or Class VI wells in the United States or comparable Underground Injection Control (UIC) well construction standards in Canada.
VI. EOR projects with CCS.
VII. Demonstrate clear and uncontested rights to the storage reservoir pore space and that the Project Proponent has filed a Risk Mitigation Covenant and secured the consent of surface owners to the filing of a Risk Mitigation Covenant or provided an alternative risk mitigation assurance acceptable to ACR as described in Section 5.3.1.5.
VIII. Demonstrate surface use agreements for the duration of the project term to conduct post-injection monitoring and, if necessary, remediation.

1.4 START DATE

The start date is defined by the *ACR standard* as the date on which the project began to reduce GHG emissions against its baseline. Due to the complexities of financing CCS projects, Project Proponents may elect a start date at the end of the design phase of a project in order to demonstrate eligibility. A third-party validation, based on the project design, will be required. Projects that elect to have a start date at the end of the design phase will require an additional validation after the facility is constructed. Alternatively, project developers may set their start date to when CO_2 is first injected and would then require a single project validation.

CCS projects that are constructed but non-operational at the time Version 2.0 of this methodology is published may apply to generate credits unless they are non-operational due to regulatory non-compliance. Projects that are under construction but not operational when Version 2.0 of this methodology is published are also eligible. Active projects that undergo a significant operational change that increases project capacity, e.g., incorporation of new CO_2 sources, installation of additional carbon capture or compression equipment, or begin injection to a different reservoir, are also eligible to participate. The additional project capacity is eligible to generate credits under this methodology.

1.5 CREDITING PERIOD

Crediting Period is 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. Since qualifying CCS projects are usually long-term (30+ years) and involve significant investment in CCS infrastructure as well as for developing individual project and monitoring plans, the Crediting Period for these projects shall be ten (10) years. This period provides an adequate term during which market participants (Project Proponents, offset buyers, registries, etc.) have a level of assurance that offsets will be generated from the project as long as they are successfully verified in accordance with the project's approved GHG Project Plan. At the end of each 10-year period, the Project Proponent may apply to renew the Crediting Period by complying with all then-current ACR requirements, re-evaluating the baseline scenario, and using emission factors, tools, and methodologies in effect at the time of Crediting Period renewal. This will also include an additionality assessment to ensure that emissions reductions and carbon capture are not a regulatory requirement or common industry practice. ACR does not limit the allowed number of Crediting Period renewals.

1.6 REPORTING PERIOD

The reporting period can be defined at the discretion of the Project Proponent, provided it conforms to ACR's guidelines on reporting periods. The *ACR Standard* requires a field visit by the verifier at minimum every 5 years. In between field visits, verification may be via a desktop assessment, which may be annual or at any other interval at the Project Proponent's discretion, but verification is required prior to any issuance of ERTs.

1.7 PROJECT TERM

The Project Term is the minimum length of time for which a Project Proponent commits to project continuance, monitoring and verification. For CCS projects the Project Term includes the period of CO_2 injection plus a period following the end of injection during which the reservoir is monitored for CO_2 plume stability and atmospheric leakage. The minimum post-injection period for CCS projects is five (5) years. The duration of post-injection monitoring shall be extended beyond five years based on the monitoring results obtained during this 5-year period and whether no leakage of CO_2 (discussed in Section 5.3.1.4) can be assured and demonstration that the CO_2 plume has stabilized. If no leakage of CO_2 cannot be assured based on the monitoring during this period or it can not be demonstrated that the plume has reached equilibrium, the Project Term will be extended in two-year increments until these requirements can be assured.

1.8 PERIODIC REVIEWS AND REVISIONS

ACR may require revisions to this methodology to ensure that monitoring, reporting, and verification systems adequately reflect changes in CCS project activities. This methodology may also be periodically updated to reflect regulatory changes, advances in technology, emission factor revisions, or expanded applicability criteria. Before beginning a project, the Project Proponent shall ensure that they are using the latest version of the methodology.

2 PROJECT BOUNDARIES

Consistent with *ACR Standard* requirements, the project boundary includes a physical boundary, a temporal boundary, and a greenhouse gas (GHG) assessment boundary. **Error! Reference source not found.** and Table 2 provide a general illustration of project boundaries, which includes the physical boundary (i.e., CO_2 sources) and assessment boundary (i.e., the GHGs emissions from each source). In addition, project boundaries include the temporal boundary, which include the temporal parameters affecting project validity and the duration of required project activities. Physical, temporal, and assessment boundaries are discussed in the following sections.

2.1 PHYSICAL BOUNDARY

The physical boundary demarcates the GHG emission sources included in the project and baseline emissions calculation (as presented in Section 4). The project boundary is intentionally drawn broadly to avoid unaccounted emissions associated with capturing and storing CO_2, including emissions from CO_2 capture, transport, and storage, as well as CO_2 recovery and re-injection operations at EOR sites, if applicable. If CO_2 is captured from more than one process or facility, then the Project Proponent may combine them within the boundary that encompasses the capture site and allocate any downstream emissions to the project. The boundary also includes emissions from the transportation, refining, and end use of any hydrocarbons produced through EOR.

The installation of CO_2 capture may impact different sources of emissions at a facility. To ensure the emissions reduction calculation approach reflects the relevant change in emissions due to the project, the physical boundary shall incorporate all GHG sources affected by the project in the baseline and project scenarios (i.e., the change in overall emissions due to capturing CO_2). This may require the inclusion of one or more emission sources from the Primary Process creating the captured CO_2. For example, a boundary for CO_2 capture at a hydrogen production unit within a refinery would encompass systems associated with the hydrogen production process but might exclude downstream units that use the hydrogen (e.g., the hydro-treating units) or other systems unaffected by the CO_2 capture system. Emissions from the CO_2 capture systems are considered project emissions.

Injection sites must demonstrate compliance with local, state/provincial, and federal regulations that are in place at the time of registration and remain in compliance with those regulations through the project.[6]

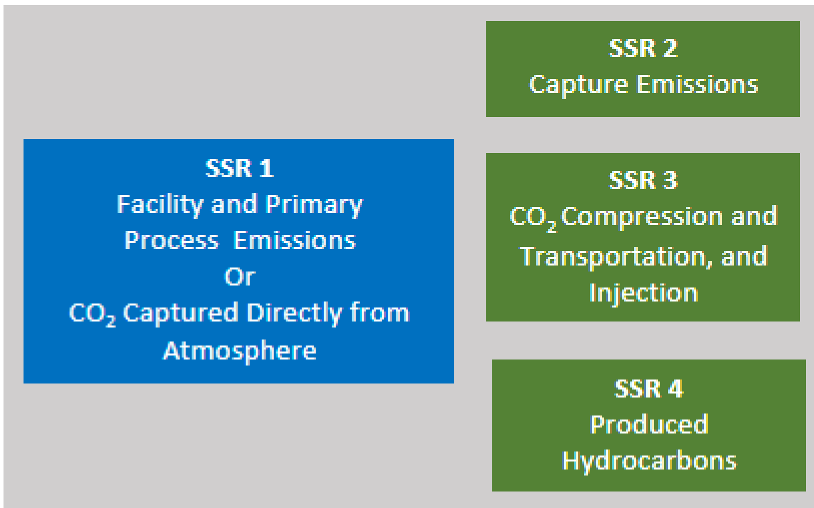

Figure 1: Sources, Sinks and Reservoirs

Table 2: Sources, Sinks and Reservoirs

SSR		DESCRIPTION	GHG	BASELINE (B) PROJECT (P)	INCLUDED OR EXCLUDED
1	Facility emissions	Primary process emissions from chemical process or energy	CO_2	B	Included
			CH_4	n/a	Excluded[7]

[6] While Project Proponents may choose to not renew the project's Crediting Period under new regulations, to maintain qualification of ERTs that have already been credited, the project must continue to comply with regulations that were in effect at project registration through the Project Term.

[7] Include GHG emissions from CH_4 emissions if those CH_4 emissions are above de minimis levels, defined as more than 0.5% of total facility wide GHG emissions.

SSR		DESCRIPTION	GHG	BASELINE (B) PROJECT (P)	INCLUDED OR EXCLUDED
		generation and consumption	N_2O	n/a	Excluded
2	Capture emissions	Emissions from capture of CO_2 from primary process	CO_2	P	Included
			CH_4	n/a	Excluded
			N_2O	n/a	Excluded
3	CO_2 compression, transportation, and injection	Emissions from the compression transportation of CO_2 from capture facility to storage site and injection into the reservoir	CO_2	P	Included
			CH_4		
			N_2O		
4	Produced hydrocarbons	Emissions from mobile mechanical equipment for plugging	CO_2	P	Included
			CH_4		
			N_2O		

2.2 GREENHOUSE GAS ASSESSMENT BOUNDARY

The greenhouse gases included in calculations of baseline emissions and project emissions are shown in Figure 1 and Table 2 and their justification in Table 3. The emissions associated with the transportation, refining, and end use of hydrocarbons produced by EOR products (i.e., produced oil or gas) are included as project emissions five years after the project start date or January 1, 2030, whichever is first. Oil production through EOR would most likely displace an equivalent quantity of oil production with a higher carbon intensity.[8] The methodology

[8] The most recent Energy Information Agency (EIA) data indicates that in 2020 (Oil imports and exports - U.S. Energy Information Administration (EIA)), the US produced 18.40 million barrels per day (MMbbl/d) of crude oil while importing 5.88 MMbbl/d during the same period. An incremental increase in domestic

encourages the production of oil with a lower carbon footprint due to the simultaneous injection and storage of anthropogenic CO_2 that would otherwise be emitted to the atmosphere but requires projects do demonstrate a net benefit to the atmosphere.

Table 3: Justification for Greenhouse Gases Considered in the Assessment Boundary

	EMISSION SOURCE	GAS	INCLUDED?	JUSTIFICATION/ EXPLANATION
BASELINE	Gas stream captured from the primary process	CO_2	Yes	CO_2 is major emission from source
		CH_4	No	Emission is negligible and exclusion is conservative
		N_2O	No	Emission is negligible and exclusion is conservative
PROJECT	**CO_2 CAPTURE**			
	Non-captured gas from the primary capture process (vented and fugitive)	CO_2	Yes	CO_2 is major emission from source
		CH_4	No	Emission is negligible and exclusion is conservative
		N_2O	No	Emission is negligible and exclusion is conservative
	Stationary combustion	CO_2	Yes	CO_2 is major emission from source
		CH_4	Yes	Included for completeness
		N_2O	Yes	Included for completeness
	Electricity and thermal energy usage	CO_2	Yes	CO_2 is major emission from source
		CH_4	Yes	Included for completeness
		N_2O	Yes	Included for completeness

oil production through EOR would offset an equivalent quantity of imported oil that is produced by primary production processes which do not involve CO_2 sequestration. Therefore, there are no incremental emissions associated with the combustion of the produced oil.

	EMISSION SOURCE	GAS	INCLUDED?	JUSTIFICATION/ EXPLANATION
	CO_2 TRANSPORT			
	Stationary combustion	CO_2	Yes	CO_2 is major emission from source
		CH_4	Yes	Included for completeness
		N_2O	Yes	Included for completeness
	Vented & fugitive emissions	CO_2	Yes	CO_2 is major emission from source
		CH_4	No	Emission is negligible and exclusion is conservative
		N_2O	No	Not contained in source emissions
	Electricity usage	CO_2	Yes	CO_2 is major emission from source
		CH_4	Yes	Included for completeness
		N_2O	Yes	Included for completeness
	Mobile (Barge/Rail/Truck)	CO_2	Yes	CO_2 is major emission from source
		CH_4	Yes	Included for completeness
		N_2O	Yes	Included for completeness
	CO_2 STORAGE			
	Stationary combustion	CO_2	Yes	CO_2 is major emission from source
		CH_4	Yes	Included for completeness
		N_2O	Yes	Included for completeness
	Vented & fugitive emissions from surface facilities	CO_2	Yes	CO_2 is major emission from source
		CH_4	Yes	Included for completeness
		N_2O	No	Not contained in source emissions

	EMISSION SOURCE	GAS	INCLUDED?	JUSTIFICATION/ EXPLANATION
	Electricity usage	CO_2	Yes	CO_2 is major emission from source
		CH_4	Yes	Included for completeness
		N_2O	Yes	Included for completeness
	Produced gas (from EOR) transferred outside project boundary	CO_2	Yes	CO_2 is major emission from source
		CH_4	No	Emission is negligible and exclusion is conservative
		N_2O	No	Not contained in source emissions
	Atmospheric leakage of emissions from the geologic reservoir	CO_2	Yes	CO_2 is major emission from source
		CH_4	No	Emission is negligible and exclusion is conservative
		N_2O	No	Not contained in source emissions

3 BASELINE DETERMINATION AND ADDITIONALITY

3.1 BASELINE DESCRIPTION

Baseline includes emissions listed in Table 1. The methodology presents two options for calculating the baseline, referred to as Projection-based and Standards-based.

3.1.1 Baseline Options

A Project Proponent selects the baseline that applies to its project, and then follow the matching calculation procedure.

PROJECTION-BASED. This option represents a baseline that would correspond with the project's actual CO_2 capture facility, absent the capture and compression system located at the CO_2 source. For example, if the CCS project includes a coal electricity generator with post-combustion capture, a Projection-based baseline would be the measured emissions from the coal plant producing the same quantity of electricity without CO_2 capture. Similarly, if the CCS project captures CO_2 from acid-gas removal associated with natural gas production, a Projection-based baseline would be the natural gas production facility operating at the same volumes of acid gas removal but with CO_2 vented to the atmosphere. For most CCS projects, the Projection-based baseline scenario will apply. Equations provided in Section 4.1.2.

STANDARDS-BASED. The Standards-based baseline can be based on a technology or specified as an intensity metric or performance standard (e.g., metric tons of carbon dioxide equivalent [tCO_2e] per unit of output). It could be site-specific or correspond with a similar technology utilized by the project's CO_2 capture equipment, but which fulfills the same purpose and function. For instance, if the CCS project includes a coal-fired electricity generator with post-combustion capture, a Standards-based baseline could be represented by a coal-fired or natural gas-fired power plant's emissions rate, expressed as metric tons CO_2/megawatt hour [MWh]. In this case, baseline emissions would be calculated by multiplying the actual MWhs delivered to the grid in the project condition (net MWh) times the approved emissions rate.

A Standards-based baseline is sector specific, at minimum, to ensure reasonable accuracy, and it could have a different emissions profile than the technology used at the CO_2 capture site.

Equation provided in Section 4.1.3.

3.1.2 Baseline Considerations for Retrofit and New-Build Carbon Capture Systems

Depending on the situation, either the Projection-based or Standards-based baseline could apply to projects that capture CO_2 at power generation or other industrial facilities.

RETROFIT CARBON CAPTURE SYSTEMS. Given the limited number of regulations that require GHG emissions reductions from facilities in the U.S., the baseline for most retrofit projects would involve the continued operation of the existing CO_2 source facility, but without carbon capture and storage – such that produced CO_2 is released to the atmosphere. This corresponds with the Projection-based baseline.

A Standards-based baseline could also apply to retrofit projects if a law or regulation affects CO_2 emissions production at the capture site, such as a mandate to meet a minimum GHG emission performance standard.

NEW BUILD CARBON CAPTURE SYSTEMS. The baseline for new facilities will often correspond with the common practice in the region and the most economic option available to the Project Proponent. As with retrofit projects, the baseline for a new build facility would likely be the operation of the project configuration without the CCS capture component that releases the produced CO_2 to the atmosphere – a Projection-based baseline. This is contingent on there being no regulations in place that require the use of certain technologies, mandate the installation of CCS, or prevent the implementation of the most common technology option.

Current regulations shall be considered in determining whether to use a Projection-based or Standards-based baseline for new and existing sources. For example, if a GHG regulation requires new sources to meet an emissions performance benchmark, the Standards-based baseline is appropriate and baseline emissions rate shall be set to this benchmark. For existing sources, a Projection-based baseline is appropriate unless there is some regulation that makes it unlikely that existing source can continue operating as in the past and is likely to be replaced by a new source having to meet the benchmark.

3.1.3 Baseline Considerations Carbon Dioxide Removals

For projects where the CO_2 is derived from the atmosphere, a Projection-based baseline shall be used. This baseline represents the project's actual CO_2 capture prior to transportation and sequestration. The Project Proponent will determine the Projection-based baseline according to actual measured quantities of CO_2 captured by the project, which would have remained in the atmosphere had the CCS project not been implemented, minus the incremental emissions generated due to CO_2 capture and compression process. The calculation uses collected data to represent the quantity of CO_2 prevented from remaining the atmosphere.

3.2 ADDITIONALITY ASSESSMENT

Emission reductions from the project must be additional or deemed not to occur in the business-as-usual scenario. The assessment of additionality shall be made based on evaluating the project using the performance standard approach as described below including passing a three-pronged additionality test. Project Proponents utilizing this methodology shall consult the latest version of the *ACR Standard*, which is updated regularly.

To qualify as additional, the project must pass a regulatory surplus test and exceed a performance standard.

3.2.1 Regulatory Surplus Test

The Project Proponent must demonstrate that there is no existing regulation that mandates the project or effectively requires the GHG emission reductions associated with the capture and/or sequestration of CO_2. Voluntary agreements without an enforcement mechanism, proposed laws or regulations, optional guidelines, or general government policies are not considered in determining whether a project is surplus to regulations. Projects that receive government incentives, such as the 45Q tax credit in the US, can be eligible for generating carbon credits if emissions reductions or carbon capture is not a regulatory requirement.

If the quantity of CO_2 captured and stored exceeds the requirements imposed by regulation, then those excess reductions are considered surplus and thereby qualify under the methodology (assuming other requirements are met). For example, if CCS enables a facility to exceed a regulatory performance standard requirement of 1,000 kgs/MWh, then the reductions down to 1,000 kgs/MWh would not be creditable (since mandated by regulation) but those reductions in excess of the requirement are considered surplus and are creditable.

Projects that are deemed to be regulatory surplus are considered surplus for the duration of their Crediting Period. If regulations change during the Crediting Period, this may make the project non-additional and thus ineligible for renewal but does not affect its additionality during the current Crediting Period.

3.2.2 Performance Standard

Projects are required to achieve a level of performance that, with respect to emission reductions or removals and technologies or practices, is significantly better than average compared with similar recently undertaken practices or activities in a relevant geographic area. The performance threshold may be:

- **PRACTICE-BASED.** Developed by evaluating the adoption rates or penetration levels of a particular practice within a relevant industry, sector or subsector within the specific region. If these levels are sufficiently low that it is determined the project activity is not common practice, then the project activity is considered additional.

- **TECHNOLOGY STANDARD.** Installation of a particular GHG-reducing technology may be determined to be sufficiently uncommon that simply installing the technology is considered additional.

In 2018, fossil fuel fired power generation, natural gas processing, ethanol production, hydrogen production, cement production, fertilizer production, and other industrial processes in the USA emitted an estimated 4,300 MMT of CO_2 into the atmosphere[9]. The Global CCS Institute, in their 2021 Global Status Report, states that globally there are currently 27 operational CCS (36.6 metric tons/year capture capacity). An additional 108 CCS projects are under construction, in development, or suspended (capture capacity of approximately 113 million metric tons/year)[10]. Table 4 below outlines the number of operational CCS projects in the US from anthropogenic CO_2 emission sources.

Table 4: Industrial Plants in the US with CCS October 2021

ANTHROPOGENIC CO_2 EMISSION SOURCE	NO. OF PLANTS	NO. OF PLANTS CURRENTLY OPERATIONAL WITH CCS[11]
Power Generation (Fossil Fuels)	3,301[12]	5
Natural Gas Processing	510[13]	7
Ethanol Plants	208[14]	4
Hydrogen Production	146[15]	1

[9] US EPA, Inventory of Greenhouse Gas Emissions and Sinks: 1990-2018 https://www.epa.gov/sites/production/files/2020-04/documents/us-ghg-inventory-2020-chapter-executive-summary.pdf, value calculated by subtracting emissions from transportation, residential use, biomass, and bunker fuel production from annual total.

[10] Global CCS Institute, 2021. The Global Status of CCS: 2021. Australia

[11] Global CCS Institute, CO2RE Facilities Database, https://co2re.co/FacilityData (accessed November 1, 2020)

[12] Table 4.1 Count of Electric Power Industry Power Plants, by Sector, by Predominant Energy Sources within the Plant, 2009 to 2020, https://www.eia.gov/electricity/annual/html/epa_04_01.html

[13] US. Natural Gas processing plant capacity and throughput have increased in recent years, U.S. Energy Information Administration, March 7, 2019, https://www.eia.gov/todayinenergy/detail.php?id=38592

[14] Renewable Fuels Association, 2019 Ethanol Industry Outlook: Powered with Renewed Energy https://ethanolrfa.org/wp-content/uploads/2019/02/RFA2019Outlook.pdf

[15] Merchant Hydrogen Plant Capacities in North America, January 2016, https://h2tools.org/hyarc/hydrogen-data/merchant-hydrogen-plant-capacities-north-america

ANTHROPOGENIC CO_2 EMISSION SOURCE	NO. OF PLANTS	NO. OF PLANTS CURRENTLY OPERATIONAL WITH CCS[11]
Nitrogen Fertilizer Production	30[16]	3
Cement Production	105[17]	1
TOTAL	**4,300**	**21**

Figure 2 shows the existing CO_2 pipeline system in the US that has evolved over the last thirty-five years. The network connects natural and anthropogenic sources of CO_2 to the following oil producing regions:

- Permian Basin in Texas and New Mexico
- Gulf Coast Basin including Mississippi, Alabama, Louisiana and Texas
- Rocky Mountain area of Wyoming and Colorado comprising the Powder River, Wind River, Great Divide, Washakie and Piceance Basins
- Williston Basin in Montana and North Dakota, and
- Midcontinent area of Kansas, Oklahoma and the Texas Panhandle

[16] U.S. Fertilizer production and mining facilities at a glance, CHS and The Fertilizer Institute, http://robslink.com/SAS/democd65/usproductionmaps.pdf

[17] Cement Plant locations in the United States https://www.cemnet.com/global-cement-report/country/united-states

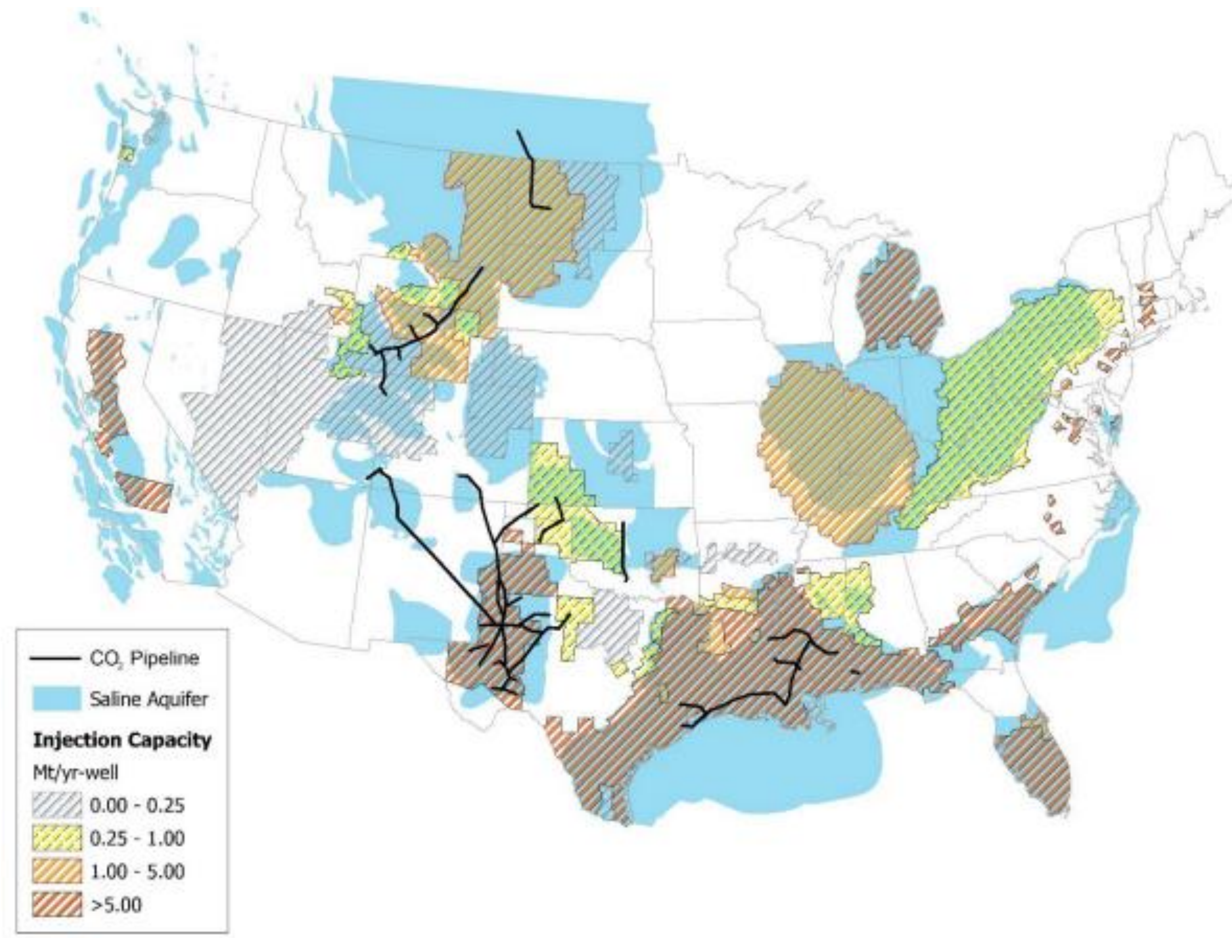

Figure 2: Major US CO_2 Pipelines[18]

In 2017, it was determined that the US has a potential storage capacity of anthropogenic CO_2 in the range of 2,367 - 21,200 GT[19]. Currently, the USA ranks closely behind Canada in the readiness of CCS deployment in terms of creating an enabling environment for the large-scale

[18] Briana Mordick Schmidt, Joshuah K. Stolaroff, Sarah E. Baker, Nathan C. Ellebracht, Whitney Kirkendall, Aaron J. Simon, George Peridas, Eric W. Slessarev, Jennifer Pett-Ridge, Simon H. Pang, Roger D. Aines, and Matthew Langholtz, Carbon Negative by 2030: CO2 Removal Options for an Early Corporate Buyer, February 2022, Lawrence Livermore National Laboratory, LLNL-TR-832071

[19] Consoli, C.P., Wildgust, N., Current status of global storage resources, 13th International Conference on Greenhouse Gas Control Technologies, GHGT-13, 14-18 November 2016, Lausanne, Switzerland. Energy Procedia 114 (2017) 4623-4628

deployment of CCS[20]. However, the adoption rates of CCS capture technologies for industrial CO_2 emission sources are extremely low, and the injection of anthropogenic CO_2 into saline and depleted formations is not yet common practice.

Based on these low penetration rates, it can be concluded that CCS projects meet a practice-based performance standard and can be considered additional as long as they are not required by regulation.

[20] Global CCS Institute, CO2RE Facilities Database. https://co2re.co/FacilityData (accessed November 1, 2020)

4 QUANTIFICATION METHODOLOGY

This section details the methods and equations to quantify baseline emissions, project emissions, and emission reductions. These procedures and equations have been adapted from the accounting framework developed by the Center for Climate and Energy Solutions.[21] Project Proponents shall determine which equations apply to their project based on an evaluation of project and baseline configurations and on project-specific conditions. Table 5 and Table 6 can be used as an aid in this determination. Supplemental quantification methods are included in Appendix B.

4.1 BASELINE EMISSIONS

Two approaches can be used to calculate baseline CO_2 emissions from the primary process and removals– Projection-based and Standards-based. To be conservative, the procedures do not calculate methane (CH_4) or nitrous oxide (N_2O) emissions. For DAC projects, CO_2 removals shall be treated as baseline emissions (Equation 1).

4.1.1 Functional Equivalence

The principle of functional equivalence dictates that the baseline emissions calculated and the project emissions measured shall provide the same function while delivering comparable products in quality and quantity. In the case of CCS projects, the implementation of CO_2 capture infrastructure may result in changes to energy consumption and/or product output which could impact the quantity of GHG emissions produced at the capture site. In some project configurations, incremental emissions associated with operating the capture system could yield an overall increase in CO_2 production and result in a larger volume of CO_2 captured and processed, relative to what the primary process would have emitted in the baseline. A power plant retrofitted with post-combustion CO_2 capture, for instance, that maintains (net) electricity production levels by burning additional coal to produce steam and electricity to power the capture system would increase overall CO_2 production. In this case, using actual measured CO_2 production values from the project to derive baseline emissions would overestimate baseline emissions.

Alternatively, a similar power plant could burn an equivalent amount of coal as the pre-retrofit plant and correspondingly produce the same amount of CO_2 as the baseline. In this case, the

[21] A Greenhouse Gas Accounting Framework for Carbon Capture and Storage Projects, Center for Climate and Energy Solutions, February 2012

capture system would not cause an increase in total CO_2 production, it could lead to the generation of less electricity. In this case, if a Project Proponent uses actual electricity production data to derive baseline emissions, it could underestimate baseline emissions.

In other project configurations, some or all of the incremental energy needed to meet the demands of the CO_2 capture system could be provided through separately powered systems, including process heaters, boilers, engines, turbines, or other fossil fuel-fired equipment. In this case, the corresponding CO_2 emissions streams would likely be separate from the captured CO_2 from the primary process and are considered project emissions.

Project Proponents shall adjust actual project data relied upon to quantify baseline emissions, if necessary. This is done to ensure that the quantified emissions reductions appropriately represent the atmospheric benefit of the CCS project and that the comparison between project and baseline emissions maintains functional equivalence.

In some cases, baseline emissions may have to be modified to ensure that projects are not being credited for capture and storage of excess CO_2 emissions. The Project Proponent shall provide evidence that the primary process facility was built and is being operated in accordance with its permit requirements and that there were no violations of process conditions or exceedances in emissions of CO_2 and other pollutants. If a violation occurred, then the effect on CO_2 emissions shall be evaluated and any increases in CO_2 over normal operations for that period will be deducted from baseline emissions.

4.1.2 Calculation Procedure for Projection-based Baseline

The Projection-based baseline uses actual measured GHG emissions or removals from the project to represent what would have occurred in the absence of CCS assuming a consistent level of production or activity. The procedure involves measuring or calculating the amount of CO_2 produced by the primary process, measured immediately downstream of the primary process. As discussed above, an adjustment factor is a part of the equation to maintain functional equivalence between the baseline and project emissions. Project Proponents would determine the appropriate way to correct measured CO_2 emissions on a project-by-project basis and justify to the validation/verification body (VVB) how the adjustment factors applied have maintained functional equivalence between the baseline and project scenarios.

For eligible DAC facilities, baseline emissions are defined as the volume of gas captured and its CO_2 concentration measured at a suitable location in the process prior to transportation or injection.

Equation 1: Total Annual Projection-based Baseline GHG Emissions

$$BE_{Projection-Based_y} = \left(Vol._{Gas\ Produced_y} - Vol._{excess\ CO_2}\right) \times \%CO_2 \times \rho CO_2 \times AF$$

WHERE

$BE_{Projection-Based_y}$	Baseline emissions for a CCS project where the baseline scenario is defined using a Projection-based approach in each year (tCO_2/yr).
$Vol._{Gas\ Produced_y}$	Volume of actual CO_2 gas produced from the primary process, metered at a point immediately downstream of the primary process (m^3 gas/yr). For DAC, the primary process is considered to be CO_2 removal.
$Vol._{excess\ CO_2}$	Volume of excess CO_2 gas produced from the primary process due to permit violations (if any) as discussed in Section 4.1.1; estimated at standard conditions in each year (m^3 gas/yr).
$\%CO_2$	$\%CO_2$ in the gas stream, monitored immediately downstream of the primary process, or for DAC facilities monitored immediately downstream of the captured gas volume measurement location, in each year (% volume).
ρCO_2	Density of CO_2 at standard conditions = 0.00190 metric ton/m^3.
AF	Baseline adjustment factor to account for incremental CO_2 from the capture equipment and included in the measured CO_2 stream (unitless).[22] Determined on a project-by-project basis. If the CO_2 capture system is separately run and operated and the corresponding CO_2 emissions are not included in the $Vol._{Gas\ Produced,\ y}$ CO_2 term, then insert 1 (one) for this term. This term is also equal to 1 (one) for CDR facilities if there are no emissions from the capture process. **NOTE:** GHG emissions from the capture system are still attributable to the project activity and must be quantified and included in project emissions as discussed in 4.2.1.

[22] This variable is included to maintain functional equivalence between the baseline and project.

4.1.3 Calculation Procedure for Standards-based Baseline

The Standards-based baseline is calculated by multiplying an emissions intensity metric or rate-based performance standard, expressed as tCO_2e/unit of output, by the actual output of the project's primary process (e.g., MWh for power generation, MMscf processed for natural gas production, etc.), as provided in Equation 2.

An applicable performance standard may be set by regulation based on the type of facility generating the captured CO_2 emissions. Procedures for collecting data from the actual project to determine the output value used to calculate baseline emissions shall be set to ensure that the quantified emissions reductions appropriately represent the impact of the CCS project.

For example, in CCS projects that involve power generation, electricity may be used to operate the CO_2 compressors or other equipment associated with the capture system, reducing the amount of electricity delivered to the grid or sold to direct-connected users, as compared to a facility without CO_2 capture. In this case, the Project Proponent shall use gross electricity production as the output instead of net electricity production.

Equation 2: Total Annual Standards-based Baseline Emissions

$$\mathbf{BE_{Standards\text{-}based} = BE_{performance\ standard} \times Output_y}$$

WHERE

$BE_{Standards\text{-}based}$	Standards-based baseline emissions for a CCS project in year y (tCO_2/yr).
$BE_{performance\ standard}$	Baseline emissions intensity metric, specific to the type of primary process that creates the CO_2 for capture, as prescribed by the regulation (tCO_2e/unit of output).
$Output_y$	Units of output from the CO_2 capture facility (e.g., MWh, MMscf, etc.) in the project condition in year y (units of output).

4.1.4 Carbon Dioxide Removal

In addition to point sources, CO_2 captured through DAC are eligible to participate in this methodology. For DAC facilities, baseline emissions are determined from the volume of CO_2 measured downstream of the capture process. Any GHG emissions from the capture process or energy generation shall be subtracted from the total CO_2 credited.

4.2 PROJECT EMISSIONS

CCS project emissions equal the sum of CO_2e emissions from CO_2 capture, transport, and storage, as shown in Equation 3.

Equation 3: Total Project Emissions

$$\mathbf{PE_y = PE_{Capture_y} + PE_{Transport_y} + PE_{Storage-P_y}}$$

WHERE

PE_y	Project emissions from CCS project in year $\mathbf{y}$ (tCO_2e/yr).
$PE_{Capture_y}$	Project emissions from CO_2 capture and compression in year $\mathbf{y}$ (tCO_2e/yr). Refer to Section 4.2.1.
$PE_{Transport_y}$	Project emissions from CO_2 transport in year $\mathbf{y}$ (tCO_2e/yr). Refer to Sections 4.2.2 and 4.2.3.
$PE_{Storage-P_y}$	Project emissions from CO_2 injection and storage in year $\mathbf{y}$ (tCO_2e/yr). Refer to Sections 4.2.4 and 4.2.5.

4.2.1 Calculation Procedures for CO_2 Capture

The following equation outlines the methods for calculating atmospheric emissions from the capture segment of CCS projects. This equation is applicable to, but not limited to, pre-combustion capture, post-combustion capture, and oxy-fuel capture at industrial sites and DAC. If emissions are captured and sequestered, they are not considered project emissions because they are not released into the atmosphere, though they will not generate carbon credits.

Equation 4: Total Annual Project Emissions from the Capture Segment

$$\mathbf{PE_{Capture_y} = PE_{C-PP_y} + PE_{C-Comb_y} + PE_{C-Indirect\ Energy_y}}$$

WHERE

$PE_{Capture_y}$	Project emissions from CO_2 capture and compression in each year (tCO_2e/yr).
PE_{C-PP_y}	Project emissions from the primary process (physical CO_2 emissions) that have not been captured by the CO_2 capture process, including project emissions from venting of CO_2 during capture and compression, and project emissions from fugitive releases of CO_2

	during capture and compression in each year (tCO_2/yr). Refer to Equation 5.
PE_{C-Comb_y}	Project emissions from on-site use of fossil fuels to operate support equipment for the CO_2 capture and compression facilities in each year (tCO_2e/yr). Refer to Equation 9.
$PE_{C-Indirect\ Energy_y}$	Project emissions from purchased electricity and thermal energy used to operate the CO_2 capture and compression systems in each year (tCO_2e/yr). Refer to Equation 10.

Consistent with the objective of providing a complete assessment of the impact of the CCS project, this quantification method accounts for all non-captured emissions from the primary process that enter the atmosphere. A post-combustion system might capture 90 percent of CO_2 created by a power production facility; thus, the 10 percent not captured is incorporated into the quantification approach to provide a comprehensive representation of the emissions profile of the capture segment of the CCS project.

The calculation approach collectively refers to CO_2 created by the primary process that is emitted to the atmosphere through vent stacks and fugitive releases from equipment at the capture and compression systems as non-captured CO_2. These are emissions that would occur without the addition of a carbon capture facility.

The following equations account for the portion of CO_2 generated from the primary process that is not captured but emitted to the atmosphere. Project Proponents calculate emissions by subtracting CO_2 transferred to the transport segment of the CCS project from total CO_2 produced from the primary process. Table 7 provides the monitoring parameters to calculate total annual CO_2 produced from the primary process and transferred to the CO_2 pipeline; it also provides the monitoring parameters necessary for calculating the CH_4 and N_2O emissions from the primary process.

Equation 5: Non-Captured CO_2e Emissions from the Primary Process at the Capture Site

$$PE_{C-PP_y} = CO_2\ Produced_{PP_y} + CO_2e\ Produced_{PP_y} - CO_2\ Transferred_{PP_y}$$

WHERE

PE_{C-PP_y}	Project emissions from the primary process that have not been captured by the CO_2 capture process, including project emissions from venting of CO_2 during capture and compression, and project emissions from fugitive releases of CO_2 during capture and compression in each year (tCO_2/yr).

$CO_2\ Produced_{PP_y}$	Total CO_2 produced from the primary process in each year (tCO_2/yr), where the volume of gas is measured directly downstream of the primary process. Refer to Equation 6.[23]
$CO_2e\ Produced_{PP_y}$	Total CH_4 and N_2O produced from the primary process in each year (tCO_2/yr). Refer to Equation 7.
$CO_2\ Transferred_{PP_y}$	CO_2 captured and transferred to the CO_2 pipeline, metered at the point of transfer with the pipeline in each year (tCO_2/yr). Refer to Equation 8.

Equation 6: Primary Process CO_2 Emissions[24]

$$\mathbf{CO_2\ Produced_{PP_y}} = \left(\mathbf{Vol._{Gas\ Produced_y}} \times \mathbf{\%CO_2} \times \mathbf{\rho CO_2}\right)$$

WHERE

$CO_2\ Produced_{PP_y}$	Total CO_2 produced from the primary process in each year (tCO_2/yr).
$Vol._{Gas\ Produced_y}$	Total volume of CO_2 gas produced from the primary process, metered continuously at a point immediately downstream of the primary process, measured at standard conditions, in each year (m^3 gas/yr).
$\%CO_2$	$\%CO_2$ in the gas stream, measured immediately downstream of the primary process, at standard conditions, each year (%volume).
ρCO_2	Density of CO_2 at standard conditions = 0.00190 metric ton/m^3.

[23] For gasification projects, the total mass of CO_2 produced would be determined based on the mass or volume and carbon content of the syngas produced from the gasifier, measured at a point upstream of the water-gas shift reactor and subsequent hydrogen purification steps. Note that carbon contained in char, slag or ash produced during gasification would not be included in the total amount of produced CO_2 unless also sequestered under this methodology.

[24] See Appendix B for a fuel-based method to calculate emissions from stationary combustion projects which occur during the primary process where direct measurement of CO_2 is not possible.

Equation 7: Primary Process CH_4 and N_2O Emissions[25, 26]

$$\mathbf{CO_2e\ Produced_{PP_y}} = \sum \left(\mathbf{Fuel_i} \times \mathbf{EF\ CH_{4_{Fuel_i}}}\right) \times \mathbf{CH_4\text{-}GWP} + \sum \left(\mathbf{Fuel_i} \times \mathbf{EF\ N_2O_{Fuel_i}}\right) \times \mathbf{N_2O\text{-}GWP}$$

WHERE

$CO_2e\ Produced_{PP_y}$	Gross amount of CH_4 and N_2O produced from the primary process in each year (tCO_2/yr).
$Fuel_i$	Total volume or mass of fuel, by fuel type **i**, input into the primary process in year each (e.g., m^3 or kg).
$EF\ CH_{4_{Fuel_i}}$	CH_4 emission factor for combustion of fossil fuel **i** (e.g., tCH_4/m^3 or tCH_4/kg of fuel).
$EF\ N_2O_{Fuel_i}$	N_2O emission factor for combustion of fossil fuel **i** (e.g., tN_2O/m^3 or tN_2O/kg of fuel).
$CH_4\text{-}GWP$	Global Warming Potential of CH_4.[27]
$N_2O\text{-}GWP$	Global Warming Potential of N_2O.

Equation 8: CO_2 Captured and Input into CO_2 Transport Pipeline

$$\mathbf{CO_2\ Transferred_y} = \mathbf{Vol}_{\mathbf{Gas\ Transferred_y}} \times \%\mathbf{CO_2} \times \boldsymbol{\rho}\mathbf{CO_2}$$

WHERE

$CO_2\ Transferred_y$	CO_2 captured and transferred to the CO_2 pipeline, metered at the point of transfer with the pipeline in each year (tCO_2/yr).
$Vol_{Gas\ Transferred_y}$	Total volume of gas that has been captured and input into the pipeline, metered at the point of transfer with the pipeline in each year ($m^3\ CO_2$/yr).

[25] Applicable to CO_2 capture projects which combust fossil fuels in the primary process and CH_4 and N_2O emissions exceed 0.5% of total facility wide GHG emissions.

[26] CH_4 and N_2O emissions from combustion of fossil fuels are calculated from stationary source combustion emission factors, available at https://www.epa.gov/climateleadership

[27] Refer to the *ACR Standard* for respective GWPs.

$\%CO_2$	$\%CO_2$ in the gas stream measured at the input to the pipeline, at standard conditions (% volume).
ρCO_2	Density of CO_2 at standard conditions = 0.00190 metric ton/m^3. Different density may be used with documentation and justification.

Emissions quantification at the CO_2 capture site also includes stationary combustion and electric-drive units to support the capture and compression processes, such as cogeneration units, boilers, heaters, engines, and turbines. For example, the operation of a coal gasifier (primary process) with a pre-combustion absorption capture unit and electric-drive compression would require an air separation unit to generate pure oxygen for the gasification process, a fossil fuel steam generation unit to supply heat to regenerate the CO_2-rich absorbent, and grid electricity to drive the compressors and other auxiliary equipment. These emissions sources are included within the capture boundary to quantify the energy use associated with the CO_2 capture process (which would not occur in the baseline scenario).

Ultimately, GHG emissions from energy use will depend on the configuration of the capture and compression facilities, the types and quantities of fossil fuels combusted, and electricity, steam and heat consumed to provide energy for the capture and compression processes.

The following equation is used to quantify direct emissions from stationary fossil fuel-driven equipment used for CO_2 capture and compression.

Equation 9: Capture Site Emissions of CO_2, CH_4, and N_2O from Stationary Combustion Associated with Auxiliary Equipment[28]

$$PE_{C-Comb_y} = \sum \left(Fuel_i \times EF\ CO_{2_{Fuel_i}}\right) + \sum \left(Fuel_i \times EF\ CH_{4_{Fuel_i}}\right) \times CH_4\text{-}GWP + \sum \left(Fuel_i \times EF\ N_2O_{Fuel_i}\right) \times N_2O\text{-}GWP$$

WHERE

PE_{C-Comb_y}	Project emissions from combustion of fossil fuels in stationary equipment used to operate the CO_2 capture and compression facilities in each year (tCO_2e/yr).
$Fuel_i$	Volume or mass of each type of fuel, by fuel type i, used to operate the CO_2 capture and compression facilities in each year (e.g., m^3/yr or kg/yr).

[28] Emission factors for CO_2, CH_4, and N_2O emissions from combustion of fossil fuels are available at https://www.epa.gov/climateleadership

$EF\ CO_{2_{Fuel_i}}$	CO_2 emission factor for combustion of fossil fuel i (e.g., tCO_2/m^3 or tCO_2/kg of fuel).
$EF\ CH_{4_{Fuel_i}}$	CH_4 emission factor for combustion of fossil fuel i (e.g., tCH_4/m^3 or tCH_4/kg of fuel).
$EF\ N_2O_{Fuel_i}$	N_2O emission factor for combustion of fossil fuel i (e.g., tN_2O/m^3 or tN_2O/ metric ton of fuel).
CH_4-GWP	Global Warming Potential of CH_4.
N_2O-GWP	Global Warming Potential of N_2O.

For some CCS project configurations, operating the CO_2 capture and compression processes includes electricity or thermal energy purchased from third parties (e.g., electric utilities or off-site co-generation facilities). Specifically, electricity may be used to operate the compressors, dehydration units, refrigeration units, circulation pumps, fans, air separation units and a variety of other equipment. Purchased steam may be used for various purposes, including regeneration of the CO_2-rich absorbent used in some capture processes for a post-combustion capture configuration. Electricity may be sourced from direct-connected generating facilities or from the regional electricity grid, while thermal energy may be sourced from nearby steam generators or cogeneration facilities. Thermal energy and electricity may be sourced from separate facilities or sourced from the same combined heat and power generation (cogeneration) facility.

Indirect emissions associated with purchased energy inputs used to operate the CO_2 capture and compression processes may need to be quantified according to, Equation 10, Equation 11, Equation 12, and Equation 13. Table 7 provides the monitoring parameters to calculate CO_2 emissions from purchased and consumed electricity, steam, and heat.

If CO_2 capture and compression systems are powered by renewable sources, this shall be documented by project proponent.

EMISSION FACTOR FOR ELECTRICITY GENERATION ($EF_{ELECTRICITY}$)

In Equation 11, the emission factor for electricity generation is determined using data from the USEPA's Emissions & Generation Resource Integrated Database (eGRID). eGRID is a comprehensive source of data on the environmental characteristics of electric power generated in the United States, including emissions of nitrogen oxides, sulfur dioxide, carbon dioxide, methane, and nitrous oxide, net generation, resource mix, and other attributes.[29] As of adoption

[29] See Emissions & Generation Resource Integrated Database (eGRID) | US EPA

of this methodology, the latest release is the eGRID2019, containing data through 2019. The latest published version of eGRID shall always be used.

eGRID2019 provides data organized by Balancing Authority Area (BAA), North American Electric Reliability Corporation (NERC) region, eGRID subregion, U.S. state, and other levels of aggregation. The BAA, eGRID subregion, and NERC region data are based on electricity generation, transmission, and distribution areas, and so effectively represent the emissions associated with the mix of GHG-emitting and non-emitting resources used to serve electricity loads in those areas.

If there is any reason to deviate from the use of eGRID emission factors, such as the project obtaining energy from alternative sources, the project proponent is responsible for tracking and reporting electricity and associated emissions.

The emission factor is selected in the order of preference below, i.e., if the BAA can be identified the emission factor from this tab must be used. Only if it is not possible to use the preferred level of aggregation is it permitted to move to the next level.

1. In eGRID2019, the BA19 tab has data for 76 BAAs across the United States. This methodology considers those BAA emission factors to be the most precise representation of emissions and thus requires the BAA emission rate to be used as long as the BAA can be identified. In the BA19 tab, look up the appropriate BAA in the left-hand column and scroll across to the column entitled "BAA annual CO_2 equivalent total output emission rate (lb/MWh)". Divide this value by 2,205 to convert it to units of tCO_2e/MWh.
2. If the BAA is not known, use the eGRID subregion data in the SRL19 tab. This includes emission factors for 27 eGRID subregions covering the United States. Look up the appropriate eGRID subregion in the left-hand column and scroll across to the column entitled "eGRID subregion annual CO_2 equivalent total output emission rate (lb/MWh)". Divide this value by 2,205 to convert it to units of tCO_2e/MWh.
3. If the BAA is not known and it is not feasible to place the project site definitively in an eGRID subregion (e.g., because it is located near a boundary between two subregions), use the data aggregated by U.S. state in the ST19 tab. This will be the least precise because electricity generation, transmission and distribution regions do not follow state boundaries. Look up the state where the project site is located in the left-hand column and scroll across to the column entitled "State annual CO_2 equivalent total output emission rate (lb/MWh)". Divide this value by 2,205 to convert it to units of tCO_2e/MWh.

Equation 10: CO_2 Emissions from Purchased and Consumed Electricity, Steam, and Heat

$$PE_{C\text{–}Indirect\ Energy_y} = PE_{Elec_y} + PE_{Cogen_y}$$

WHERE

$PE_{C\text{–}Indirect\ Energy_y}$	Project emissions from purchased electricity and thermal energy used to operate the CO_2 capture and compression facilities in each year (tCO_2e/yr).
PE_{Elec_y}	Project emissions from grid electricity used to operate the CO_2 capture and compression facilities in each year (tCO_2e/yr). Refer to Equation 11.
PE_{Cogen_y}	Project emissions from thermal energy and/or electricity purchased from third party operated heat and/or power generation facilities used to operate the CO_2 capture and compression facilities in each year (tCO_2e/yr). Refer to Equation 12.

Equation 11: CO_2 Emissions from Purchased and Consumed Electricity

$$PE_{Elec_y} = Electricity \times EF_{Electricity}$$

WHERE

PE_{Elec_y}	Project emissions from grid electricity used to operate the CO_2 capture and compression facilities in each year (tCO_2e/yr).
Electricity	Total metered grid electricity usage from equipment used to operate the CO_2 capture and compression facilities in each year (MWh).
$EF_{Electricity}$	Emission factor for electricity generation in the relevant region, by (in order of preference) BAA, eGRID subregion, or State (tCO_2e/MWh).

Equation 12: CO_2, CH_4, N_2O Emissions from Purchased and Consumed Steam and/or Heat[30]

$$\mathbf{PE_{Cogen_y}} = \sum \left(\mathbf{Fuel_i} \times \mathbf{EF\ CO_{2_{Fuel_i}}}\right) + \sum \left(\mathbf{Fuel_i} \times \mathbf{EF\ CH_{4_{Fuel_i}}}\right) \times \mathbf{CH_4\text{-}GWP} + \sum \left(\mathbf{Fuel_i} \times \mathbf{EF\ N_2O_{Fuel_i}}\right) \times \mathbf{N_2O\text{-}GWP}$$

WHERE

PE_{Cogen_y}	Project emissions from thermal energy and/or electricity purchased from third party operated heat and/or power generation facilities used to operate the CO_2 capture and compression facilities in each year (tCO_2e/yr).
$Fuel_i$	Proportionate volume or mass of each type of fuel, by fuel type i, combusted by the third-party cogeneration unit to supply electricity or thermal energy to the CO_2 capture and compression facilities in each year (e.g., m^3/yr or kg/yr). Refer to Equation 13.
$EF\ CO_{2_{Fuel_i}}$	CO_2 emission factor for combustion of fuel i (e.g., tCO_2/m^3 or tCO_2/kg of fuel).
$EF\ CH_{4_{Fuel_i}}$	CH_4 emission factor for combustion of fuel i (e.g., tCH_4/m^3 or tCH_4/kg of fuel).
$EF\ N_2O_{Fuel_i}$	N_2O emission factor for combustion of fuel i (e.g., tN_2O/m^3 or $tN_2O/$ metric ton of fuel).
$CH_4\text{-}GWP$	Global Warming Potential of CH_4.
$N_2O\text{-}GWP$	Global Warming Potential of N_2O.

[30] Emission factors for CO_2, CH_4, and N_2O emissions from combustion of fossil fuels are available at https://www.epa.gov/climateleadership

Equation 13: Apportionment of Cogeneration Emissions by Product

$$\mathbf{Fuel_i = Total\ Fuel_{Cogen}} \times \left[\frac{\left(\mathbf{Heat_{CCS\ Project} + Electricity_{CCS\ Project}}\right)}{\left(\mathbf{Heat_{Cogen} + Electricity_{Cogen}}\right)}\right]$$

WHERE

$\mathrm{Fuel_i}$	Proportionate volume or mass of each type of fuel, by fuel type $\mathbf{i}$, combusted by the third-party cogeneration unit to supply electricity or thermal energy to the CO_2 capture and compression facilities in each year (e.g., m^3/yr or metric tons/yr).[31]
$\mathrm{Total\ Fuel_{Cogen}}$	Total volume or mass of each type of fuel, by fuel type $\mathbf{i}$, combusted by the third-party cogeneration unit supplying electricity or thermal energy to the CO_2 capture and compression facilities in each year (e.g., m^3/yr or metric tons/yr).
$\mathrm{Heat_{CCS\ Project}}$	Quantity of thermal energy purchased from the third-party cogeneration unit to operate the CO_2 capture facilities (MWh/year).
$\mathrm{Electricity_{CCS\ Project}}$	Quantity of electricity purchased from the third-party cogeneration unit to operate the CO_2 capture and compression facilities (MWh/year).
$\mathrm{Heat_{Cogen}}$	Total quantity of thermal energy generated by the third-party cogeneration unit (MWh/year).
$\mathrm{Electricity_{Cogen}}$	Total quantity of electricity generated by the third-party cogeneration unit (MWh/year).

4.2.2 Calculation Procedures for CO_2 Transport

The GHG emission quantification approach for the transport segment of a CCS project includes the full pipeline system from the CO_2 delivery point at the capture site (downstream of the compressor) to the CO_2 delivery point at the storage site. The calculation methodology also applies to CO_2 transported in containers (e.g., by barge, rail, or truck).

For pipeline transport, the emissions quantification procedures in this section apply to a CCS project that includes a dedicated pipeline moving CO_2 from the capture site to the storage site. For CO_2 transport using a network of pipelines, where project CO_2 can be commingled with CO_2

[31] The CO_2 capture unit may only require a portion of the total electricity and/or heat output from the cogeneration unit so it might be necessary to account for the fraction of emissions from the cogeneration unit that are attributable to the CCS project

from other sources (e.g., in West Texas), different quantification procedures using system-wide emission factors can be used as outlined in Section 4.2.3.

GHG emissions from CO_2 transport by pipeline include CO_2 emissions from venting and fugitive releases as well as CO_2, CH_4 and N_2O emissions from stationary combustion and electricity use. For transport of CO_2 in containers, mobile sources (barge, rail, or truck) are the main source of GHG emissions. There may be venting and fugitive emissions depending on the nature of equipment used to transfer CO_2 into transportation equipment and transport the CO_2 in containers. These emissions shall also be calculated and accounted for under project emissions from the transport segment. Table 7 provides monitoring parameters to calculate emissions from CO_2 transport.

The following equation shows an approach to calculate GHG emissions from the transport segment of a CCS project.

Equation 14: Total Project Emissions from the Transport Segment

$$PE_{Transport_y} = PE_{T-Comb_y} + PE_{T-VF_y} + PE_{T-Electricity_y} + PE_{T-Mobile_y}$$

WHERE

$PE_{Transport_y}$	Project emissions from CO_2 transport in year y (tCO_{2e}/yr).
PE_{T-Comb_y}	Project emissions from combustion of fossil fuels in stationary equipment used to maintain and operate the CO_2 pipeline facilities in each year (tCO_2e/yr). Refer to Equation 15. This term does not apply to CO_2 transport by barge, rail, or truck.
PE_{T-VF_y}	Project emissions from venting events and fugitive releases from the CO_2 pipeline or from the CO_2 containers during transport and associated equipment in each year (tCO_2e/yr). Refer to Equation 16.
$PE_{T-Electricity_y}$	Project emissions from electricity consumed to operate the CO_2 pipeline and associated equipment in each year (tCO_2e/yr). Refer to Equation 19. This term does not apply to CO_2 transport by barge, rail, or truck.
$PE_{T-Mobile_y}$	Project emissions from each mode of transport (barge, rail, or truck) used to transport the CO_2 containers from capture site to the storage site in each year (tCO_2e/yr). Refer to Equation 20. This term does not apply to CO_2 transport by pipeline.

Stationary combustion equipment that is a part of CO_2 pipeline could include engines, turbines, heaters, etc. For some projects, additional compression may be required along the pipeline or at an interconnection with a pipeline that is operated at a higher pressure. Combustion emissions associated with energy inputs for CO_2 transport are quantified according to the following equation. If transportation system is powered by renewable sources, this must be demonstrated by project proponent.

Equation 15: CO_2, CH_4, N_2O Emissions from Stationary Combustion for CO_2 Transport[32]

$$PE_{T-Comb_y} = \sum\left(Fuel_i \times EF\ CO_{2_{Fuel_i}}\right) + \sum\left(Fuel_i \times EF\ CH_{4_{Fuel_i}}\right) \times CH_4\text{-}GWP + \sum\left(Fuel_i \times EF\ N_2O_{Fuel_i}\right) \times N_2O\text{-}GWP$$

WHERE

PE_{T-Comb_y}	Project emissions from combustion of fossil fuels in stationary equipment to maintain and operate the CO_2 pipeline infrastructure in each year (tCO_2e/yr).
$Fuel_i$	Volume or mass of each type of fuel, by fuel type i, used in each year (e.g., m^3/yr or kg/yr).
$EF\ CO_{2_{Fuel_i}}$	CO_2 emission factor for combustion of fossil fuel i (e.g., tCO_2/m^3 or tCO_2/kg of fuel).
$EF\ CH_{4_{Fuel_i}}$	CH_4 emission factor for combustion of fossil fuel i (e.g., tCH_4/m^3 or tCH_4/ kg of fuel).
$EF\ N_2O_{Fuel_i}$	N_2O emission factor for combustion of fossil fuel i (e.g., tN_2O/m^3 or tN_2O/ metric ton of fuel).
$CH_4\text{-}GWP$	Global Warming Potential of CH_4.
$N_2O\text{-}GWP$	Global Warming Potential of N_2O.

This methodology presents a mass balance approach to calculate transport-related vented and fugitive CO_2 emissions. Venting and fugitive emissions of CO_2 are grouped together in the mass balance determination.

[32] Emission factors for CO_2, CH_4, and N_2O emissions from combustion of fossil fuels are available at https://www.epa.gov/climateleadership

The following equation is used to quantify venting and fugitive emissions from the CO_2 pipeline according to the mass balance method.

Equation 16: Vented and Fugitive CO_2 Emissions from CO_2 Transport

$$\mathbf{PE_{T-VF_y} = CO_2Received_{Capture_y} - CO_2Supplied_{Storage_y}}$$

WHERE

PE_{T-VF_y}	Project emissions from venting events and fugitive releases from the CO_2 pipeline and associated equipment in each year (tCO_2e/yr).
$CO_2Received_{Capture_y}$	CO_2 captured and input into the pipeline, metered at the point of transfer with the capture site in each year (tCO_2/yr). Refer to Equation 17.
$CO_2Supplied_{Storage_y}$	CO_2 supplied to the storage site operator, metered at the point of transfer with the storage site in each year (tCO_2/yr). Refer to Equation 18.

Equation 17: CO_2 Captured and Input into CO_2 Pipeline

$$\mathbf{CO_2Received_{Capture_y} = Vol._{Gas\ Received_y} \times \%CO_2 \times \rho CO_2}$$

WHERE

$CO_2Received_{Capture_y}$	CO_2 captured and input into the pipeline or container, metered at the point of transfer with the capture site in each year (tCO_2/yr).
$Vol._{Gas\ Received_y}$	CO_2 captured and input into the pipeline or container, metered at the point of transfer with the capture site in each year at standard conditions (m^3 CO_2/yr).
$\%CO_2$	CO_2 in the gas stream measured at the point of transfer with the capture site (% volume).
ρCO_2	Density of CO_2 at standard conditions = 0.00190 metric ton/m^3. Different density may be used with documentation and justification.

Equation 18: CO_2 Transferred from CO_2 Pipeline to CO_2 Storage Site

$$\mathbf{CO_2Supplied_{Storage_y} = Vol._{Gas\ Supplied_y} \times \%CO_2 \times \rho CO_2}$$

WHERE

$CO_2Supplied_{Storage_y}$	CO_2 supplied to the storage site operator, metered at the point of transfer with the storage site in each year (tCO_2/yr).
$Vol._{Gas\ Supplied_y}$	Volume of gas that has been supplied to the storage site operator, metered at the point of transfer with the storage site in each year at standard conditions (m^3 CO_2/yr).
$\%CO_2$	$\%CO_2$ in the gas stream measured at the transfer with the storage site (% volume).[33]
ρCO_2	Density of CO_2 at standard conditions = 0.00190 metric ton/m^3. Different density may be used with documentation and justification.

A mass balance method is not appropriate in situations where the uncertainty of the measured values is greater than the magnitude of the quantified emissions.[34] In those cases, vented and fugitive emissions shall be estimated using a component count method. To use the component count method, an inventory of equipment (fittings, valves, etc.) is compiled in order to apply fugitive emission factors to estimate emissions from the pipeline. Venting events must also be logged to estimate venting emissions (e.g., intentional pipeline releases). The component-count method to calculate vented and fugitive emissions is presented in the CO_2 storage segment calculation procedures, Equation 25.

In some CCS project configurations, grid electricity may be purchased to operate the CO_2 transport infrastructure. In particular, electric-drive compressors may be used for supplemental compression along the CO_2 pipeline, where grid connectivity permits. The indirect emissions associated with purchased electricity for CO_2 transport can be quantified according to the following equation. If the project proponent did not purchase electricity from the grid to power electric equipment, an accounting of the generation of that electricity will be required. If renewable sources of energy are used, detailed accounting of the sources is required.

[33] Composition of gas delivered to storage site is assumed to be same composition as the gas at inlet to the pipeline or received by container.

[34] This can be done by performing an uncertainty analysis and comparing the result with the difference between $CO_2\ Received_{Capture_y}$ and $CO_2\ Supplied_{Storage_y}$

Equation 19: CO_2e Emissions from Electricity Consumption for CO_2 Transport

$$\mathbf{PE_{T\text{-}Elec_y} = Electricity \times EF_{Electricity}}$$

WHERE

$PE_{T\text{-}Elec_y}$	Project emissions from electricity usage from equipment used to operate the CO_2 pipeline transport infrastructure in each year (tCO_2e/yr).
$Electricity$	Total metered electricity usage from equipment used to operate the CO_2 pipeline transport infrastructure in each year (MWh).
$EF_{Electricity}$	Emission factor for electricity generation in the relevant region, by (in order of preference) BAA, eGRID subregion, or State (tCO_2e/MWh). See Section 4.2.1 for estimation procedures.

Mobile source emissions for CO_2 transport by barge, rail, or truck are calculated by aggregating the ton-miles transported by each mode and multiplying the individual totals by an appropriate mode-specific emission factor. Total CO_2e emissions are calculated from the following equation:

Equation 20: CO_2e Emissions from Mobile Transport of CO_2 Containers[35]

$$\begin{aligned}\mathbf{PE_{T\text{-}Mobile_y}} &= \sum \left(\mathbf{Ton\text{-}miles_i \times EF\ CO_{2_i} \times 10^{-3}}\right) \\ &\quad + \sum \left(\mathbf{Ton\text{-}miles_i \times EF\ CH_{4_i} \times 10^{-6}}\right) \times \mathbf{CH_4\text{-}GWP} \\ &\quad + \sum \left(\mathbf{Ton\text{-}miles_i \times EF\ N_2O_i \times 10^{-6}}\right) \times \mathbf{N_2O\text{-}GWP}\end{aligned}$$

WHERE

$PE_{T\text{-}Mobile_y}$	Total emissions from all modes of transport (barge, rail, or truck) that were used to transport the CO_2 containers from capture site to the storage site in each year (tCO_2e/yr).
$Ton\text{-}miles_i$	Ton-miles for each mode of transport, by mode type **i**, used to transport the CO_2 containers in each year. **NOTE:** the ton-miles calculation includes the weight of the container plus the weight of the contained CO_2 (ton-miles/yr).

[35] Emission factors for CO_2, CH_4, and N_2O emissions for product transport are available at https://www.epa.gov/climateleadership

$EF\ CO_{2_i}$	CO_2 emission factor for mode i (barge, rail, or truck), (kg/ton-mile).
$EF\ CH_{4_i}$	CH_4 emission factor for mode i (barge, rail, or truck), (g/ton-mile).
$EF\ N_2O_i$	N_2O emission factor for mode i (barge, rail, or truck), (g/ton-mile).
$CH_4\text{-}GWP$	Global Warming Potential of CH_4.
$N_2O\text{-}GWP$	Global Warming Potential of N_2O.

4.2.3 Calculating CO_2 Transport Emissions According to System-Wide Emission Factors

The emissions quantification procedure for the CO_2 pipeline transport segment corresponds with a CCS project that includes a dedicated pipeline moving CO_2 from the capture site to the storage site. However, CCS projects could use pipeline systems that carry streams of CO_2 from multiple capture sites to one or more geologic storage reservoirs. Thus, an emissions accounting approach that prorates CO_2 losses according to a proportional use of a pipeline's annual throughput or a share of a storage site's annual CO_2 injection is appropriate. The project proponent shall work with the entities responsible for the CO_2 pipeline to obtain a reasonable system-wide emission factor (percent losses of the total) and calculate its CO_2 losses (emissions). Pipeline operators could also derive a system-wide fugitive CO_2 emission factor from a comprehensive component count assessment.[36] For completeness, a comprehensive loss factor shall also incorporate vented and stationary combustion emission sources within the appropriate GHG assessment boundary, and emissions from purchased electricity.

4.2.4 Calculation Procedures for CO_2 Storage

The emissions calculation procedures for CO_2 storage cover direct CO_2, CH_4, and N_2O emissions from stationary combustion; CO_2 and CH_4 emissions from venting and fugitive releases to the atmosphere; and indirect CO_2e emissions from purchased electricity use; and leakage of injected CO_2 from the reservoir to the atmosphere. For projects involving EOR, the procedures also account for any CO_2 that is produced with the hydrocarbons and transferred offsite (i.e., the CO_2 is not re-injected into a reservoir within the project boundary). For projects that produce hydrocarbons, any emissions from production, refining, or use must be included in

[36] Project developers could derive a CO_2 pipeline emission factor based on natural gas transmission factors and then convert from methane to CO_2 (emissions CO_2/kilometer of pipeline). The American Petroleum Institute's Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry (2009) is one source for a pipeline emission factor. Available at: https://www.api.org/~/media/Files/EHS/climate-change/2009_GHG_COMPENDIUM.pdf

project emissions. For EOR projects, emissions can also come from recycling and re-injection equipment, production wells, and hydrocarbon processing and storage facilities.

The emissions quantification methodology for CO_2 storage includes all emissions sources located between the point of transfer from the CO_2 pipeline up to and including the injection wells. For EOR projects, it incorporates producing wells and surface facilities related to the hydrocarbon gathering, storage and separation facilities and the infrastructure used to process, purify, and compress CO_2 and other gases produced from the formation, and re-inject it back into the formation. Additionally, CO_2 entrained in or dissolved in hydrocarbons (crude oil or natural gas) or wastewater that is removed or distributed off-site (e.g., sold, disposed of and/or not re-injected) is accounted for as a source of fugitive emissions.

Emissions from energy inputs to operate the facilities at storage formations are accounted for by using common quantification methods based on the quantities and types of energy inputs. Vented CO_2 emissions from surface facilities are quantified on an event basis. Fugitive CO_2 emissions from injection wells and surface facilities are calculated according to a component count approach. The method to calculate leaked CO_2 from the geologic storage reservoir to the atmosphere, should it occur, would be reservoir-specific and is addressed in Section 4.2.6.

The methodology does not treat CO_2 produced from wells at EOR sites that is recycled and re-injected into the storage formation as an emission, provided the CO_2 remains within the closed loop system and is thus prevented from entering the atmosphere. Unintentional CO_2 releases from the recycle system (including from production wells, gas separation and cleaning equipment) are treated as fugitive emissions and accounted for in Equation 24. Intentionally vented CO_2 in the recycle system (for operational purposes) is treated as a vented emission and accounted for in Equation 23.

The following Equation 21 outlines the methods for calculating emissions from CO_2 storage. Table 7 provides monitoring parameters for calculating emissions from CO_2 storage.

Equation 21: Total Project Emissions from CO_2 Storage

$$\mathbf{PE_{Storage\text{-}P_y} = PE_{S\text{-}P\text{-}Comb_y} + PE_{S\text{-}P\text{-}Vent_y} + PE_{S\text{-}P\text{-}Fug_y} + PE_{S\text{-}P\text{-}Elec_y} + PE_{S\text{-}P\text{-}CO_2Transfer} + PE_{S\text{-}P\text{-}Leakage_y} + PE_{Production_y}}$$

WHERE

$PE_{Storage\text{-}P_y}$	Project emissions from CO_2 injection and storage in each year (tCO_2e/yr).
$PE_{S\text{-}P\text{-}Comb_y}$	Project emissions from combustion of fossil fuels in stationary equipment at the storage site – e.g., to maintain and operate the CO_2 handling and injection wells, CO_2 recycling devices, and associated

	hydrocarbon production facilities in each year (tCO_2e/yr). Refer to Equation 22.
$PE_{S\text{-}P\text{-}Vent_y}$	Project emissions from venting of CO_2 at the injection wells or other surface facilities located between the point of transfer from the CO_2 pipeline and the injection wells into the formation. For EOR projects this also includes emissions at the producing wells, at the hydrocarbon gathering processing and storage facilities, or at the CO_2 processing and recycling facilities in each year (tCO_2e/yr). Refer to Equation 23.
$PE_{S\text{-}P\text{-}Fug_y}$	Project emissions from fugitive releases of CO_2 or CH_4 at the injection wells or other surface facilities located between the point of transfer from the CO_2 pipeline and the injection wells. For EOR projects this also includes emissions at the producing wells, at the hydrocarbon gathering processing and storage facilities, at the CO_2 processing and recycling facilities, and from CO_2 entrained in hydrocarbons or water produced from the formation and distributed offsite in each year (tCO_2e/yr). Refer to Equation 24.
$PE_{S\text{-}P\text{-}Elec_y}$	Project emissions from consumption of electricity used to operate equipment at the producing formation at the storage site in each year (tCO_2e/yr). Refer to Equation 27.
$PE_{S\text{-}P\text{-}CO_2Transfer}$	Produced CO_2 from an enhanced oil or gas recovery operation transferred offsite in each year (tCO_2/yr). EOR only. Refer to Equation 28.
$PE_{S\text{-}P\text{-}Leakage_y}$	Project emissions from leakage of injected CO_2 from the geologic storage reservoir in the storage formation to the atmosphere in each year (tCO_2e/yr). For information on accounting for CO_2 leakage emissions from geologic storage formations to the atmosphere see Section 4.2.6.
$PE_{Production_y}$	Project emissions (tCO_2e/yr) from transportation, refining, and end use of hydrocarbons produced from an EOR project. These emissions are included beginning five years after the project start date or January 1, 2030, whichever is first. Refer to Equation 29.

Various types of stationary combustion equipment may be used to maintain and operate the CO_2 injection, storage, processing facilities and to operate the injection facilities (e.g., batteries, gathering and recycling systems, oil-water-gas separators). The following equation is used to quantify GHG emissions from all stationary fossil fuel-driven equipment used to operate the CO_2 injection and storage facilities.[37]

Equation 22: CO_2, CH_4, N_2O Emissions from Stationary Combustion and Flaring for CO_2 Storage[38]

$$\mathbf{PE_{S\text{-}P\text{-}Comb_y}} = \sum \left(\mathbf{Fuel_i} \times \mathbf{EF\ CO_{2_{Fuel_i}}}\right) + \sum \left(\mathbf{Fuel_i} \times \mathbf{EF\ CH_{4_{Fuel_i}}}\right) \times \mathbf{CH_4\text{-}GWP} + \sum \left(\mathbf{Fuel_i} \times \mathbf{EF\ N_2O_{Fuel_i}}\right) \times \mathbf{N_2O\text{-}GWP} + \mathbf{PE_{Flaring_y}}$$

WHERE

$PE_{S\text{-}P\text{-}Comb_y}$	Project emissions from combustion of fossil fuels in stationary equipment at the storage site – e.g., to maintain and operate the CO_2 handling and injection wells, CO_2 recycling devices, and EOR-associated hydrocarbon production facilities in each year (tCO_2e/yr).
$Fuel_i$	Volume or mass of each type of fuel, by fuel type i, used to inspect, maintain, and operate the CO_2 storage infrastructure and hydrocarbon production facilities in each year (e.g., m^3/yr or kg/yr).
$EF\ CO_{2_{Fuel_i}}$	CO_2 emission factor for combustion of fossil fuel i (e.g., tCO_2/m^3 or tCO_2/kg of fuel).
$EF\ CH_{4_{Fuel_i}}$	CH_4 emission factor for combustion of fossil fuel i (e.g., tCH_4/m^3 or tCH_4/kg of fuel).
$EF\ N_2O_{Fuel_i}$	N_2O emission factor for combustion of fossil fuel i (e.g., tN_2O/m^3 or tN_2O/kg of fuel).
$CH_4\text{-}GWP$	Global Warming Potential of CH_4.
$N_2O\text{-}GWP$	Global Warming Potential of N_2O.
$PE_{Flaring_y}$	Project emissions from flaring of gases at hydrocarbon production facilities in year y (tCO_{2e}/yr). Only applicable to EOR facilities that flare gases that may contain CO_2 originating from the producing formation. See Equation 40 (Appendix B).

[37] Appendix B provides a procedure for calculating emissions from combusting hydrocarbons produced at the formation (e.g., in flares).

[38] Emission factors for CO_2, CH_4, and N_2O emissions from combustion of fossil fuels are available at https://www.epa.gov/climateleadership

Venting may occur at the injection wells or at other surface facilities, located between the CO_2 transfer meter at the pipeline and the injection wells. For EOR projects, it could also happen at the production wells, the hydrocarbon production and storage facilities, or at the facilities used to process and recycle the produced CO_2 for re-injection into the formation. Planned venting may take place during shutdowns and maintenance work, while unplanned venting may occur during upsets to operations. Venting events shall be logged and gas concentrations reported. If CH_4 is vented, emissions must be incorporated into project emissions

The following equation can be used to calculate vented emissions from the injection wells and other surface facilities at the CO_2 storage site.

Equation 23: Vented CO_2e Emissions from CO_2 Storage

$$PE_{S\text{-}P\text{-}Vent_y} = \sum_{j=1}^{2}\sum_{i=1}^{I} N_{Blowdown_i} \times V_{Blowdown_i} \times \%GHG_j \times \rho_{GHG_j} \times GWP_j \times 0.001$$

WHERE

$PE_{S\text{-}P\text{-}Vent_y}$	Project emissions from vented CO_2 and CH_4 at the injection wells or other surface facilities located between the point of transfer from the CO_2 pipeline and the injection wells in the producing formation. For EOR projects, this can also occur at the producing wells, at the hydrocarbon gathering processing and storage facilities, or at the CO_2 processing and recycling facilities in each year (tCO_2e/yr).
$N_{Blowdown_i}$	Number of blowdowns for equipment i in each year, obtained from blowdown event logs retained by storage site operator.
$V_{Blowdown_i}$	Total volume of blowdown equipment chambers for equipment i (including pipelines, manifolds, and vessels between isolation valves) (m^3, ft^3). For well releases use measured or estimated gas volumes released using procedures in USEPA subpart W.[39]
$\%GHG_j$	Concentration of GHG 'j' in the injected gas in year y (volume percent GHG, expressed as a decimal fraction). j=1 for CO_2 and j=2 for CH_4.

[39] US Environmental Protection Agency. Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems, Final Rule: Subpart W. November 30, 2010; and subsequent amendments available at https://www.epa.gov/ghgreporting/subpart-w-petroleum-and-natural-gas-systems

ρ_{GHG_j}	Density of relevant GHG (CO_2 or CH_4) at conditions in the blowdown chamber, kg/m^3 or kg/ft^3. At standard conditions ρ_{CO_2}= 0.0538 kg/ft^3 and ρ_{CH_4}= 0.0196 kg/ft^3).[40]
GWP_j	100-year Global Warming Potential of relevant GHG
0.001	Conversion factor to convert from kg to metric tons.

Fugitive emissions of CO_2, and in some cases CH_4, may occur at the injection wells or at other surface facilities, located between the CO_2 pipeline transfer meter and the injection wells. Fugitive emissions for EOR projects could also occur at production wells, the hydrocarbon production and storage facilities, and/or at the facilities used to process and recycle the produced CO_2 for re-injection into the formation. Fugitive emission sources could include fittings, flanges, valves, connectors, meters, and headers (large pipes that mix the oil stream from multiple wellheads). Fugitive emissions may also result from the release of residual CO_2 entrained or dissolved in produced oil, water or gas that is transferred from the hydrocarbon recovery facilities to downstream users.

Fugitive CO_2 and CH_4 emissions from injection wells and other surface equipment are calculated on a component count approach. Fugitive emissions of CO_2 entrained in or dissolved in hydrocarbon liquids, gases, or produced formation water and distributed off-site are calculated based on quantities of crude oil, water and gas produced and the CO_2 content of each product. Produced water is often injected back into the producing formation as part of the EOR process. If the field operates in this way, these volumes are not included in this fugitive emissions calculation. Project Proponents shall only include fluids leaving the project boundary or if fluids are not handled in a closed-loop system where CO_2 or other GHGs could escape.

The following equation is used to calculate fugitive emissions from the injection wells and other surface facilities at the CO_2 storage site.

Equation 24: Fugitive CO_2e Emissions from Wells and Surface Equipment

$$PE_{\text{S-P-Fugitive}_y} = PE_{\text{S-P-Fug Equipment}_y} + PE_{\text{S-P-Fug Entrained } CO_{2_y}}$$

WHERE

$PE_{\text{S-P-Fugitive}_y}$	Project emissions from fugitive releases of CO_2 or CH_4 at the injection wells or other surface facilities located between the point of transfer from the CO_2 pipeline and the injection wells. For EOR

[40] For CO_2 Injection pump blowdowns, it may be necessary to use the density of CO_2 at supercritical conditions, which can be obtained from the National Institute of Standards and Technology (NIST) Database of thermodynamic properties using the Span and Wagner Equation of State.

	projects emissions can be at the producing wells, at the hydrocarbon gathering processing and storage facilities, at the CO_2 processing and recycling facilities, and from CO_2 entrained in hydrocarbons or water produced from the formation and distributed off-site in each year (tCO_2e/yr).
$PE_{S\text{-}P\text{-}Fug\ Equipment_y}$	Fugitive emissions of CO_2 (and CH_4 if relevant) from equipment located at the injection wells or other surface facilities located between the point of transfer from the CO_2 pipeline and the injection wells and for EOR projects at the producing wells, hydrocarbon gathering processing and storage facilities; and CO_2 processing and recycling facilities in each year (tCO_2e/yr). Refer to Equation 25.
$PE_{S\text{-}P\text{-}Fug\ Entrained\ CO_{2y}}$	Fugitive emissions of CO_2 entrained in or dissolved in hydrocarbon liquids or gases or water produced from the formation and distributed off-site (sold or otherwise disposed of and not re-injected) in each year (tCO_2/yr). Refer to Equation 26. For EOR only.

Equation 25: CO_2 and CH_4 Fugitive Emissions from Equipment Leaks

$$PE_{S\text{-}P\text{-}Fug\ Equipment_y} = \sum_{j=1}^{2}\sum_{s=1}^{S} Count_s \times EF_s \times T_s \times \%GHG_j \times \rho_{GHG_j} \times GWP_j \times 0.001$$

WHERE

$PE_{S\text{-}P\text{-}Fug\ Equipment_y}$	Fugitive of GHG "j" (CO_2 and CH_4, if relevant) from equipment located at the injection wells or other surface facilities located between the point of transfer from the CO_2 pipeline and the injection wells and for EOR at the producing wells, hydrocarbon gathering processing and storage facilities, and CO_2 processing and recycling facilities in each year (tCO_2e/yr).
$Count_s$	Total number of each type of emission source at the injection wellheads and at surface facilities located between the point of transfer from the CO_2 pipeline and the injection wells and for EOR at the producing wells, at the hydrocarbon gathering processing and storage facilities, and at the CO_2 processing and recycling facilities.
EF_s	Population emission factor for the specific fugitive emission source, 's', in Table W1-A and Tables W-3 through Table W-7 of Subpart W (standard cubic feet per hour per component).

T_s	Total time that the equipment associated with the specific fugitive emission source s was operational in year y (hours). Where equipment hours are unknown, assume 8760 hours/year.
$\%GHG_j$	Concentration of GHG "j" (CO_2 or CH_4) in the injected or produced gas (Volume fraction CO_2 or CH_4). j=1 for CO_2 and j=2 for CH_4.
ρ_{GHG_j}	Density of relevant GHG (CO_2 or CH_4) at standard conditions in kg/m^3 or kg/ft^3. At standard conditions ρ_{CO_2}= 0.0538 kg/ft^3 and ρ_{CH_4}= 0.0196 kg/ft^3).
GWP_j	100-year Global Warming Potential of relevant GHG
0.001	Conversion factor to convert from kg to metric tons.

Equation 26: CO_2 Fugitive Emissions Entrained in Produced Hydrocarbons

$$\begin{aligned} PE_{S\text{-}P\text{-}Fug\text{-}Entrained_{CO_2}{}_y} &= Vol._{Gas\ Sold} \times \%CO_{2\ Gas\ Sold} \times \rho CO_2 \times 0.001 \\ &+ \left(Mass_{Water\ Prod} \times Mass\ Frac_{CO_2\ in\ Water}\right) \\ &+ \left(Mass_{Oil\ Prod} \times Mass\ Frac_{CO_2\ in\ Oil}\right) \end{aligned}$$

WHERE

$PE_{S\text{-}P\text{-}Fug\text{-}Entrained_{CO_2}{}_y}$	Fugitive emissions or other losses of CO_2 entrained or dissolved in crude oil/other hydrocarbons, produced water and natural gas that have been separated from the produced CO_2 for sale or disposal. Calculated based on quantities of crude oil, water and gas produced and the CO_2 content of each product (tCO_2/yr).
$Vol._{Gas\ Sold}$	Volume of natural gas or fuel gas, produced from the formation that CO_2 is being injected into, that is sold to third parties or input into a natural gas pipeline in year y (m^3/yr, measured at standard conditions).
$\%CO_{2\ Gas\ Sold}$	$\%CO_2$ in the natural gas or fuel gas that is sold to third parties or input into a natural gas pipeline, in year y (% volume).
ρCO_2	Density of CO_2 at standard conditions (1.899 kg/m^3). Different density may be used with documentation and justification.

0.001	Conversion factor to convert from kg to metric tons.
$\text{Mass}_{\text{Water Prod}}$	Mass of water produced from the formation that CO_2 is being injected into, that is disposed of or otherwise not re-injected back into the formation (metric tons/yr). This assumes a closed loop system- if CO_2 concentrations are lower when water is re-injected than when it is extracted from the formation, those CO_2 must be measured and reported. If operators are using a closed loop water handling system, proponents may assume that CO_2 is being captured.
$\text{Mass Frac}_{CO_2\text{ in Water}}$	Mass fraction of CO_2 in the water produced from the formation.
$\text{Mass}_{\text{Oil Prod}}$	Mass of crude oil and other hydrocarbons produced from the formation that CO_2 is being injected into the formation (metric tons/year).
$\text{Mass Frac}_{CO_2\text{ in Oil}}$	Mass fraction of CO_2 in the crude oil and other hydrocarbons produced from the formation.

Purchased electricity may be used to operate pumps, compressors, and other sequestration equipment at the injection site. For EOR projects, this can also include producing wells; oil and gas gathering equipment, storage, and processing facilities (e.g., oil-water-gas separators); or CO_2 processing, compression, recycling, and re-injection facilities. For example, many EOR projects install additional water pumping capacity to alternate water injection and CO_2 injection (water alternating gas or WAG injection), which may also require electricity. Electric compression could be used to recycle produced CO_2 and other gases for re-injection into the formation. In addition to the recycle compressors, additional electric-drive equipment may be used to operate vapor recovery units to recover gasses from oil and water tanks, to operate flash gas compressors which increase the pressure of the recovered vapors for recycling, to operate glycol dehydrators and glycol circulation pumps that remove moisture from the produced gas, and to operate other auxiliary equipment such as instrument air compressors and cooling fans.

Indirect GHG emissions from purchased electricity used to operate equipment at the EOR operations are quantified according to the following equation.

Equation 27: CO_2e Emissions from Purchased Electricity Consumption for CO_2 Storage

$$PE_{S\text{-}P\text{-}Elec_y} = Electricity \times EF_{Electricity}$$

WHERE

$PE_{S\text{-}P\text{-}Elec_y}$	Project emissions from electricity used to operate equipment at the CO_2 storage site in each year (tCO_2e/yr).
Electricity	Total metered electricity usage from equipment used to operate the storage site and the hydrocarbon production facilities in year y (MWh).
$EF_{Electricity}$	Emission factor for electricity generation in the relevant region, by (in order of preference) BAA, eGRID subregion, or State (tCO_2e/MWh). See Section 4.2.1 for estimation procedures

A Project Proponent could move produced-CO_2 between EOR production fields if it includes the multiple fields within the project boundary (making sure to account for emissions from the relevant stationary combustion, vented, and fugitive sources at all the fields, and between fields, in which the captured CO_2 is injected). In some instances, however, CO_2 can be transferred out of the project boundary. While this CO_2 is not necessarily an emission to the atmosphere, Project Proponents shall nevertheless account for it as an emission rather than treating it as if it were sequestered from the atmosphere.

Equation 28 presents the approach to calculate emissions from CO_2 transferred outside the project boundary. Note: Project Proponents shall not include any CO_2 volumes that were sold to third parties and already accounted for under Equation 26.

Equation 28: CO_2 Transferred Outside Project Boundaries

$$PE_{S\text{-}P\text{-}CO_2 Transfer} = Vol_{CO_2 Transfer} \times \rho CO_2 \times 0.001$$

WHERE

$PE_{S\text{-}P\text{-}CO_2 Transfer}$	Produced CO_2 from an EOR operation transferred outside project boundary in each year (tCO_2/yr).
$Vol_{CO_2 Transfer}$	Volume of produced CO_2 from an enhanced oil or gas operation transferred outside project boundary in each year under standard conditions (m^3, ft^3).

ρCO_2	Density of CO_2 at standard conditions (1.899 kg/m^3 or 0.0538 kg/ft^3).
0.001	Conversion factor to convert from kg to metric tons.

4.2.5 Calculation Procedures for Emissions from Produced Oil

Emissions from the transportation, refining, and end use of produced oil are considered project emissions and must be quantified. These emissions shall be included as project emissions beginning five years after the project start date or January 1, 2030, whichever is first. Project Proponents may use country or regional averages to quantify their emissions or calculate emissions based on the given emissions factors and their individual project specifications. Equation 29 presents the approach to calculate emissions from CO_2 from hydrocarbons produced by a project. An example calculation is shown in Table 10, Appendix A.

Equation 29: Emissions from Produced Hydrocarbons

$$PE_{Production_y} = PE_{Transportation} + PE_{Refining} + PE_{End\ Use}$$

WHERE

$PE_{Production_y}$	Transportation, refining, and end use emissions from produced hydrocarbons (tCO_2/yr).
$PE_{Transportation}$	CO_2e emissions from transportation of produced oil including from oil field to refinery, refinery to distribution center, and transportation of crude and refined oil outside of country boundaries. Emission factors can be found in Table 11, **Error! Not a valid result for table.**, Table 14, Table 15, Table 18 and Table 19 in Appendix A to determine average regional emissions. Project specific emissions may be calculated using known distances traveled and emissions factors found in Appendix A. If calculating project specific emissions, Project Proponents must provide chain of custody tracking to show distances traveled and mode of transportation.
$PE_{Refining}$	CO_2e emissions from refining based on produced oil API gravity from Table 13 in Appendix A. Project specific emissions may be calculated using known produced oil properties and emissions factors found in Appendix A. If calculating project specific

	emissions, Project Proponents must supply documentation to detailing deviation from average refining emissions of average API gravity oil.
$PE_{End\ Use}$	CO_2e emissions from end use based on produced oil API gravity from Table 16 and Table 17 in Appendix A. End-use emissions may be calculated using emissions factors found in Appendix A. Most oil produced is consumed as fuel. Project proponents must supply chain of custody documentation to demonstrate specific end-uses of produced oil.

4.2.6 Accounting for Atmospheric Leakage of CO_2 from the Storage Volume

Project Proponents must demonstrate that there is a competent confining layer that will prevent atmospheric leakage of CO_2 emissions from the storage volume. Atmospheric leakage shall be monitored during the entire Project Term, which includes the injection period and a time-period following the end of injection as defined in Section 1.7. Methods to assure the long-term storage of CO_2 beyond the Project Term will be required; these and associated reversal risk mitigation measures are outlined in Section 5.3.1.5.

The following general equation to account for atmospheric leakage from the CO_2 storage volume reproduces a formula from the EPA's Greenhouse Gas Reporting Program. It directs storage site operators to identify leakage pathways from the subsurface and aggregate total annual emissions from each CO_2 emissions pathway, should a leak be detected.

In this methodology, the details of detecting and estimating atmospheric leakage are discussed in Section 5.3.1. If atmospheric leakage is detected during injection operations, it must be quantified and deducted as project emissions in the year the leakage was detected using Equation 2930. If the estimated atmospheric leakage is large and exceeds the ERs calculated for that year (See Section 4.3 for calculation of ERs), it can be mitigated by options discussed in Section 6.4 (Table 8).

Equation 30: Atmospheric Leakage of CO_2 Emissions from CO_2 Storage Volume During the Injection Period[41]

$$CO_{2_{Atm.\ Leakage-INJ_y}} = \sum_{z=1}^{Z} CO_{2_{z_y}}$$

WHERE

$CO_{2_{Atm.\ Leakage-INJ}}$	Total mass of CO_2 emitted to the atmosphere through subsurface leakage from the formation in year y during the injection period (metric tons).
CO_{2_z}	Total mass of CO_2 emitted through leakage pathway z in year y (metric tons).
z	Leakage pathway.

Equation 31 is used to report atmospheric leakage that occurs after the injection period. Mitigation of post-injection leakage is discussed in Section 6.4.

[41] 40 CFR §98.443(e), Eq. RR-10, 40

Equation 31: Atmospheric Leakage of CO_2 Emissions from CO_2 Storage Volume After the Injection Period

$$CO_{2_{Atm.\ Leakage-PI}} = \sum_{z=1}^{Z} CO_{2_z}$$

WHERE

$CO_{2_{Atm.\ Leakage-PI}}$	Total mass of CO_2 emitted to the atmosphere through subsurface leakage from the formation after the injection period (metric tons).
CO_{2_z}	Total mass of CO_2 emitted through leakage pathway z (metric tons).
z	Leakage pathway.

4.3 EMISSION REDUCTIONS

As shown in Equation 32, overall GHG emission reductions (ERs) from the CCS project equal Baseline Emissions minus Project Emissions. For eligible CDR facilities, baseline emissions are equivalent to the volume of gas captured and its CO_2 concentration.

Equation 32: Total Annual GHG Reductions

$$GHG\ ER_y = BE_y - PE_y$$

WHERE

$GHG\ ER_y$	Total annual GHG reductions from the CCS project (tCO_2e/yr).
BE_y	Baseline CO_2e emissions in each year (from Sections 4.1 or 4.2, tCO_2e/yr).
PE_y	Project CO_2e emissions in each year (from Section 4.3, tCO_2e/yr).

5 DATA COLLECTION AND MONITORING

5.1 BASELINE EMISSIONS MEASUREMENT

Baseline emission measurement parameters and considerations are summarized in Table 5 for the Projection-based and Standards-based calculation procedures. Details of the calculation procedures are included in Section 4.

Table 5: Overview of Baseline Emissions Calculation Procedures

TYPE OF BASELINE	GHGS	DESCRIPTION	MONITORING CONSIDERATIONS
PROJECTION BASED BASELINE	CO_2 To be conservative, CH_4 and N_2O excluded from the baseline quantification	**SECTION 4.1.2** Equation 1 Baseline emissions for a Projection-based baseline are calculated by measuring total CO_2 produced by the primary process in the actual project. In certain cases, the amount of CO_2 used to calculate baseline emissions may need to be adjusted to account for the incremental CO_2 generated to meet the energy requirements of the capture process. This could occur if the energy required to operate the CO_2 capture process equipment is provided by electricity or thermal energy generated from the same process producing the captured CO_2. Quantify the incremental mass of CO_2 generated at the capture site (to adjust the measured CO_2 value and properly account for the	Total volume of CO_2 produced by the actual project's primary process. Steam used to meet the parasitic loads from the CO_2 capture and compression equipment, if necessary.

TYPE OF BASELINE	GHGS	DESCRIPTION	MONITORING CONSIDERATIONS
		parasitic load from the CO_2 capture equipment) by calculating the CO_2 emissions from using steam to regenerate the CO_2 absorber according to facility engineering design information or from metered steam usage and steam conversion factors appropriate for the facility. Further, any additional CO_2 emissions that could result from poor or negligent operation of the primary process, or from not meeting regulations, which are included in the baseline shall be deducted as excess CO_2 emissions. Determine excess CO_2 emissions from violations to facility permit conditions and deduct from baseline as indicated in Equation 1.	
STANDARDS BASED BASELINE	CO_2 To be conservative, CH_4 and N_2O excluded from the baseline quantification	**SECTION 4.1.3 EQUATION 2** The Standards-based baseline is calculated by multiplying emissions intensity metric or performance standard, expressed as (tCO_2e/unit of output), by the actual output of the project's primary process (e.g., MWh for power generation, MMscf processed for natural gas production). The emissions intensity metric may be a region-specific or CCS project-type specific standard that is set by Federal, State, or Local Regulatory Agencies. Procedures for collecting data from the actual project to determine the output	Measurement of output based on the type of primary process. Output shall be measured to account for the total output from the primary process that would have occurred in the absence of the project.

TYPE OF BASELINE	GHGS	DESCRIPTION	MONITORING CONSIDERATIONS
		value used to calculate baseline emissions shall be set to maintain functional equivalence between baseline emissions and project emissions and ensure that the quantified emissions reductions appropriately represent the impact of the CCS project.	

5.2 PROJECT EMISSIONS MEASUREMENTS

Project emission sources and GHG measurement parameters are summarized in Table 6. Details of the calculation procedures are included in Section 4. In addition to measurement parameters shown in Table 6, a detailed monitoring, reporting, and verification (MRV) plan must be developed for each geologic storage site used in the CCS project. The MRV plan is discussed in Section 5.3.

Table 6: Overview of Project Emissions Calculation Procedures

EMISSION SOURCES TYPE & GHGS	DESCRIPTION	KEY MONITORING PARAMETERS
	CO_2 CAPTURE	
Total Capture Emissions CO_2; CH_4; N_2O	**SECTION 4.2.1, EQUATION 4** Total project emissions from CO_2 capture processes, including direct and indirect emissions.	N/A
Non-captured CO_2 from the primary process Vented & Fugitive CO_2	**SECTION 4.2.1, EQUATION 5,EQUATION** 6, Equation 7, **AND EQUATION** 8 CO_2 emissions from the primary process, which has not been captured by the CO_2 capture equipment and transferred to the transport (pipeline) segment. Non-captured CO_2 includes CO_2 emitted to the atmosphere from the capture site via vent stacks at the primary process and via venting or fugitive releases from other equipment at the capture and compression facilities.	Total volume of gas produced from the primary process, and captured and input into the pipeline

EMISSION SOURCES TYPE & GHGS	DESCRIPTION	KEY MONITORING PARAMETERS
	This quantity of CO_2 is equal to the difference between the total quantity of CO_2 produced and the quantity of CO_2 input into the pipeline.	
Stationary Combustion CO_2; CH_4; N_2O	**SECTION 4.2.1,** **EQUATION** 7 **AND Equation** 9 A fuel-based calculation method, which applies to primary process CH_4 and N_2O emissions for projects that generate CO_2 for capture through combustion, and equipment used to capture and compress CO_2, including cogeneration units, boilers, heaters, engines, turbines, flares, etc., which are owned and controlled by the capture site located at all capture sites. This can also apply to cogeneration units operated by third parties supplying process energy (e.g., steam, electricity) that are used by the project	Annual amount of fossil fuel burned, by fuel type
Electricity and Thermal Energy Use CO_2; CH_4; N_2O	**SECTION 4.2.1, Equation 10, Equation** 11, **Equation** 12, **AND Equation** 13 Indirect emissions from purchased and consumed electricity and thermal energy (steam) used to operate the CO_2 capture and compression equipment. Electricity may be used to operate the CO_2 compressors, dehydration units, refrigeration units, circulation pumps, fans, air separation units and a variety of other equipment. Purchased steam may be used for various purposes, including regeneration of the CO_2-rich absorbent used for a post-combustion capture configuration.	Total quantities of electricity and steam used to operate the CO_2 capture equipment
	CO_2 TRANSPORT	
Total Transport Emissions CO_2; CH_4; N_2O	**SECTION 4.2.2, EQUATION 14** Total Project Emissions from CO_2 transport, including vented, fugitive, stationary combustion, and purchased and consumed electricity and mobile sources.	N/A

EMISSION SOURCES TYPE & GHGS	DESCRIPTION	KEY MONITORING PARAMETERS
Stationary Combustion CO_2; CH_4; N_2O	**SECTION 4.2.2, EQUATION 15** Emissions from fossil fuel combustion to operate equipment used to transport CO_2 to the storage site. For some projects, additional compression may be required along the pipeline or at an interconnection with a pipeline that is operated at a higher pressure. A variety of stationary combustion equipment may be used to inspect, maintain, and operate the CO_2 pipeline. Stationary combustion equipment could include engines, turbines, and heaters etc. that are under the direct control of the CO_2 pipeline operator.	Annual amount of fossil fuel burned, by fuel type
Vented & Fugitive CO_2	**SECTION 4.2.2, EQUATION 16, Equation** 17, **Equation** 18 Vented and fugitive emissions during CO_2 transportation are calculated according to a mass balance approach using metered values at the point of transfer at the capture site and at the storage site. Fugitive emissions may arise from leakage of CO_2 from equipment such as flanges, valves, and flow meters. Emissions could also arise from compressor seal vents or pressure release valves. As discussed in Section 4.2.2 in certain situations, emissions shall be calculated according to an event-based approach for vented emissions and a component-count method for fugitive emissions. See "Vented CO_2" & "Fugitive CO_2" sources under "CO_2 Storage".	Component count of fugitive emission sources; hours of operation for equipment
Electricity Use (if required) CO_2; CH_4; N_2O	**SECTION 4.2.2,** **EQUATION** 19 Indirect emissions from electricity used to operate the CO_2 transport infrastructure. In some CCS project configurations, electric-drive compressors may be used for supplemental compression along the CO_2 pipeline, where grid connectivity exists.	Metered quantity of electricity used to operate the CO_2 transport equipment

EMISSION SOURCES TYPE & GHGS	DESCRIPTION	KEY MONITORING PARAMETERS
Mobile Sources (for transport by barge, rail, or truck) CO_2; CH_4; N_2O	**SECTION 4.2.2, EQUATION 20** Emissions associated with the mode of transport (barge, rail, or truck) used to transport CO_2 containers from the capture to storage site. Multiple modes of transport may be used, and the emissions associated with each mode shall be calculated separately and aggregated.	Records of CO_2 container weights, amount of fuel consumed, and mileage for each trip by each transport mode.
CO_2 STORAGE		
Total Storage Emissions – CO_2; CH_4; N_2O	**SECTION 4.2.4, EQUATION 21** Total Project Emissions from CO_2 storage including stationary combustion, vented, fugitive, and electricity consumption emissions.	N/A
Stationary Combustion CO_2; CH_4; N_2O	**SECTION 4.2.4, EQUATION 22** Emissions from fossil fuel combustion to operate equipment used to store CO_2 in the formation. Equipment could be used to operate, maintain, or inspect the CO_2 injection, storage, processing, and recycling facilities and to operate the hydrocarbon production and processing facilities (e.g., gathering systems, oil-water-gas separators for EOR). Emissions may occur from combustion of fossil fuels or combustion of hydrocarbons produced from the formation (e.g., in flares).	Annual amount of fossil fuel burned, by fuel type
Vented CO_2; CH_4	**SECTION 4.2.4, EQUATION 23** Emissions from CO_2 venting at the storage site – e.g., the injection wells or other surface facilities located between the point of transfer with the CO_2 pipeline and the injection wells. For EOR, venting may also occur at the production wells, the hydrocarbon production and storage facilities or at the facilities used to process and recycle the produced CO_2 for re-injection into the	Number of venting events; volume of CO_2 per event.

EMISSION SOURCES TYPE & GHGS	DESCRIPTION	KEY MONITORING PARAMETERS
	formation. Planned venting may occur during shutdowns and maintenance work, while unplanned venting may occur during process upsets. The amount of CO_2 vented would be determined based on the number of events and the volume of gas contained within the equipment.	
Fugitive CO_2; CH_4 (Excluding atmosphere leakage from the storage volume)	**SECTION 4.2.4, EQUATION 24, 25, 26** Fugitive emissions calculated according to a component count method. Fugitive emissions at the storage site are unintended CO_2 leaks from equipment that occur at the injection wells and other surface facilities, located between the transfer meter at the pipeline and the injection wells, and, in EOR, between the producing wells and hydrocarbon production facilities. Examples of fugitive CO_2 sources for EOR operations include production wells, hydrocarbon production and storage facilities, and equipment used to process and recycle produced CO_2 for re-injection into the formation. Specific locations where CO_2 leaks occur include fittings, flanges, valves, connectors, meters, and headers (which are large pipes that mix the oil stream from multiple wellheads). Fugitive emissions may also result from the release of residual CO_2 entrained or dissolved in produced oil, water or gas that is transferred from the hydrocarbon recovery facilities to downstream users.	Component count of fugitive emission sources; hours of operation for equipment
Electricity Use CO_2; CH_4; N_2O	**SECTION 4.2.4,** **EQUATION** 27 Indirect emissions from electricity use at the CO_2 storage site. Grid electricity may be used to operate pumps, compressors and other equipment at the injection wells and producing wells; at oil and gas gathering, storage and processing facilities (e.g., oil-water-gas separators); or at CO_2 processing, compression, recycling, and re-injection facilities. Electric compression may also be used to recycle	Metered quantity of electricity used to operate CO_2 storage and recycling equipment

EMISSION SOURCES TYPE & GHGS	DESCRIPTION	KEY MONITORING PARAMETERS
	produced CO_2 and other gases for re-injection into the formation. Electric-drive equipment may also be used to operate vapor recovery units to recover vapors from oil and water tanks, to operate flash gas compressors to increase the pressure of the recovered vapors for recycling, to operate glycol dehydrators and glycol circulation pumps that remove moisture from the produced gas, and to operate other auxiliary equipment such as instrument air compressors and cooling fans.	
Transferred CO_2 CO_2	**SECTION 4.2.4, EQUATION 278** While not technically an emission, CO_2 transferred outside the project boundary (i.e., produced CO_2 from an EOR operation not re-injected but moved offsite) is deducted from claimed emissions reductions. If an EOR site operator intends to move produced-CO_2 between fields, then the boundary would encompass the multiple fields employed (making sure to account for emissions from all relevant stationary combustion, vented, and fugitive emissions sources).	Volume of produced CO_2 from an EOR operation transferred outside project boundary
Emissions from Produced Hydrocarbons CO_2e	**SECTION 4.2.4, EQUATION 29** Emissions from the production, refining, and end use of fossil fuels produced through EOR. Accounting of these emissions shall commence five years after the project start date or January 1, 2030, whichever is first.	Hydrocarbons produced through EOR.
Atmospheric leakage of CO_2 from the storage volume CO_2	**SECTION 4.2.4, EQUATION 2930, 31** For properly selected, operated, and closed CO_2 storage operations, atmospheric leakage of CO_2 emissions from the geologic reservoir will not normally occur. Should it occur then emissions shall be calculated on a site-by-site basis as described in Section 5.3.1.6. For CO_2 storage, the project-specific MRV Plan would include a strategy for detecting and	Total mass of CO_2 emitted through leakage pathways to atmosphere

EMISSION SOURCES TYPE & GHGS	DESCRIPTION	KEY MONITORING PARAMETERS
	quantifying any surface CO_2 leakage – i.e., leakage to atmosphere estimated based on monitoring and measurements completed as part of the MRV plan.	

5.3 MONITORING, REPORTING, AND VERIFICATION (MRV) PLAN

The IOGCC's Task Force on Carbon Capture and Geologic Storage concluded that monitoring and verification of CCS projects would be accomplished best in the subsurface, given the uncertainties and changing technologies of surface monitoring techniques.[42] The Task Force has recommended that the operator submit a comprehensive monitoring plan that is tailored to the specific characteristics and potential risks of the site. Similar recommendations were made by the USDOE, which indicated that MRV programs need to be flexible and site-specific to adapt to the inherent variability and heterogeneity of geologic systems in both onshore and offshore settings. MRV plans also change in scope as a project progresses from the pre-injection phase to the post-injection phase. For all these reasons, MRV plans need to be tailored to site-specific geologic conditions and operational considerations.[43] The requirements in this methodology are aligned with regulatory standards in Canada, the US, and other international standards including ISO.

5.3.1 MRV Plan Framework

A MRV framework for CCS projects shall include the following components:

- Determination of the storage volume that is expected to contain the injected CO_2 during and after the injection period, determined through modeling and flow simulations.
- Identification of potential leakage pathways within this storage volume (usually well bores, faults, and fractures). This information can also feed into the flow simulation model as a potential source of uncertainty.
- Characterization and remediation of potential leakage pathways, as needed. This can help reduce the probability of leakage and reduce uncertainty in detecting atmospheric leakage.

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[42] Storage of Carbon Dioxide in Geologic Structures, A Legal and Regulatory Guide for States and Provinces, The Interstate Oil and Gas Compact Commission, September 2007

[43] Best Practices for Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations – 2012 Update, DOE/NETL-2012/1568, October 2012

- Development of a monitoring strategy to demonstrate effective retention of anthropogenic CO_2 during injection and post-injection periods and for detection of the potential for atmospheric leakage.
- A strategy for quantifying any atmospheric leakage of CO_2.
- A plan for monitoring the parameters included in Table 7.

5.3.1.1 DETERMINATION OF STORAGE VOLUME

The storage volume is the part of a formation planned to contain the injected CO_2, which includes a vertical and lateral boundary. The vertical boundary shall be set at the top of the confining zone. A detailed characterization of the confining zone must be included in the MRV and should include an analysis of the formation properties including porosity, permeability, lithology, thickness, lateral continuity, capillary entry pressure for CO_2, and assessment of seal mineralogy to determine the suitability for containment of the CO_2 stream.[44] The lateral boundary shall be set initially at the expected lateral extent of the plume. The lateral extent is determined through flow simulations of the injection and modeled to a point in time, post injection, when the CO_2 plume stabilizes, including pressure stabilization and plume location within the reservoir. The simulation shall account for uncertainties in modeled parameters and potential leakage pathways that could lead to CO_2 migration to reservoirs outside of the project boundaries or the atmosphere. It may be necessary to redefine the lateral boundary during operations, if the actual injection process differs from the modeled scenarios or other changes are detected that affect the extent of the lateral boundary. Both vertical and lateral boundaries shall encompass the limits of acceptable CO_2 migration.

5.3.1.2 IDENTIFICATION AND REMEDIATION OF POTENTIAL ATMOSPHERIC LEAKAGE PATHWAYS

Potential leakage pathways shall be determined through a detailed site characterization. Examples of conduits for CO_2 leaks to the atmosphere include CO_2 injection wells, oil or gas production wells, monitoring wells, plugged or abandoned wells, and faults and fractures (penetrating both the storage reservoir and the cap rock). While for properly selected, operated, and closed CO_2 storage operations, CO_2 emissions from the geologic reservoir to the atmosphere should not occur, assessing for potential leakage pathways is an important part of a monitoring program.

Site characterization includes the development of a complete catalogue of existing wells penetrating the injection zone or in the near vicinity of the reservoir, including information on the current well status, well construction data (and plugged/abandoned if applicable) including any

[44] International Organization for Standardization (ISO), 2017, Standard 27914, Carbon dioxide capture, transportation, and geological storage — Geological storage

cement bond logs available. Assurance as to the adequacy of the plugging of abandoned wells is essential.

A corrective action plan shall be developed for those wells that are considered to be high or uncertain risk for leakage (i.e., poor condition of cement, poor maintenance, and penetrating the oil reservoir and confining zones). The corrective action plan may involve either remediation or monitoring for pressure changes or leakage at the well.

Competent well construction, completion, and plugging are important to prevent leakage. All CO_2 injection wells in the US must meet Class VI well requirements and wells used for EOR operations must meet Class II well requirements outlined by the USEPA underground injection control (UIC) program.[45] There may be additional State requirements that affect the construction, completion, operation, plugging, and testing of Class II and Class VI wells. There may be additional regulatory requirements if injection wells are located offshore. Operators shall comply with all applicable State rules affecting Class II and Class VI wells. As an example, standards and procedures for Class II well operation in the State of Texas are discussed in Appendix C.

For CCS projects in Canada, federal and provincial requirements must be met for well construction and plugging.

5.3.1.3 MONITORING STRATEGY

The monitoring strategy shall be designed to demonstrate effective retention of the injected anthropogenic CO_2 within the storage volume during and after injection. Based on site evaluation and geological parameters in the storage volume, simulations of potential failure scenarios that include a range of uncertainty in modeled parameters and site characteristics shall be developed. Based on the sensitivities of individual parameters to the outcomes of those simulations, the Project Proponent shall determine the specific monitoring parameters to be monitored, the monitoring tools to be used, and the sampling frequency. The requirements of this methodology are aligned with CCS regulatory requirements in the US and Canada, International Organization for Standardization (ISO) recommendations.

A fluid flow model is an essential component of the monitoring strategy. A fluid flow model that is calibrated with formation data, well information, and production history (EOR and depleted reservoir projects) shall be used to predict CO_2 distribution during the injection and post-injection phases of the project. To update and compare the model results with project performance, material balances for total field CO_2 injection, resulting from imported CO_2 (and recycled CO_2 recovered from oil production and re-injected into the reservoir) as well as any water injected, shall be maintained. The observed material balances for fluids (oil, gas, water, CO_2) shall be compared to the fluid production predicted by the model.

[45] USEPA, 40CFR Part 146, Underground Injection Control Program: Criteria and Standards

If project operators are already required to perform certain test procedures as part of meeting regulatory requirements, then those procedures shall be incorporated into the project's MRV. For example, many regulators require periodic Mechanical Integrity Tests (MITs) to assure well integrity. These activities can help in the early detection of CO_2 leakage out of the injection zone and allow for remedial actions to be taken in a timely manner, thereby reducing the probability of atmospheric leakage from well bores.

Monitoring shall be designed so that it is sensitive to the leakage signal. Project Proponents shall select appropriate monitoring equipment and establish CO_2 detection thresholds to calibrate monitoring systems in a manner that provides confidence in the monitoring program's ability to accurately confirm the effectiveness of CO_2 storage. The data collected shall test the correctness of key modeling assumptions. The Project Proponent shall identify key project-specific parameters and thresholds that are indicative of leakage and determine appropriate ranges such that exceedances are indicative of leakage or trigger the project proponent to gather additional data to determine if there has been leakage.

Depending on site-specific conditions, the Project Proponent shall determine whether the monitoring approach would benefit from establishing pre-injection levels. If deemed beneficial, these measurements shall be done for a sufficient period of time that allows for the collection of data that are representative of site conditions prior to the initiation of injection. On-going research on pre-injection monitoring techniques and approaches can be used as a valuable resource to develop a project-specific monitoring plan and also for fine-tuning the project model. Innovative strategies to determine sources of CO_2 in groundwater in the absence of pre-injection data include the use of stable carbon isotopic signatures, noble gases, and other metrics can be utilized. The results of on-going research on site monitoring can provide data to determine its value in a pre-injection monitoring approach.[46]

5.3.1.4 POST INJECTION MONITORING

Following completion of CO_2 injection, monitoring shall be maintained during the post-injection phase until the end of the Project Term to assure no atmospheric leakage. The absence of atmospheric leakage during the Project Term is considered assured when it can be verified that no migration of injected CO_2 is detected across the boundaries of the storage volume and the modeled scenarios indicate that the CO_2 will remain contained within the storage volume. Specific monitoring tools shall be determined based on the site-specific experience gained during the pre-injection and operational phases of the project. With the cessation of injection and in the absence of any other changes to reservoir conditions, the pressures within the reservoir should equilibrate and the movement of CO_2 within the reservoir should stabilize. Therefore, minimal lateral movement is expected and tracking of the lateral extent of the CO_2 plume through appropriate measurements (such as pressure) and modeling will be adequate. Due to buoyancy effects, the CO_2 plume will tend to migrate to the upper regions of the reservoir

[46] Gulf Coast Carbon Center (GCCC) | Bureau of Economic Geology (utexas.edu)

where it will be constrained by the caprock. Therefore, changes in these subsurface measurements made above the confining zone may be indicative of potential leakage.

The minimum post-injection monitoring period for CCS projects is five (5) years. During this period, subsurface pressure shall be recorded and changes in pressure measurements evaluated, to determine if they are consistent with expected or modeled changes or are indicative of leakage. Other monitoring tools shall be implemented in accordance with the site's monitoring plan to assure no leakage. Although atmospheric leakage has not necessarily occurred if the CO_2 migrates to regions outside the storage volume boundaries, it cannot be verified that no leakage has occurred, and additional steps are necessary in this case. Project Proponents may need to redefine the boundaries of the storage volume. For example, if there is evidence of lateral movement outside the boundaries of the storage volume, then the lateral boundaries shall be extended to regions beyond the original storage volume. However, Project Proponents shall evaluate for the possibility of any new potential atmospheric leakage pathways and either remediate them and/or modify the monitoring strategy to detect for leakage under new failure scenarios. The duration of post-injection monitoring shall be extended beyond five years if no leakage cannot be assured at the end of the 5-year period. In this case, the Project Term will be extended in two-year increments and monitoring shall be continued until no leakage is assured.

5.3.1.5 POST-PROJECT TERM REQUIREMENTS FOR STORAGE OF CO_2

The Project Proponent shall file and, if the Project Proponent is not the owner of the pore space comprising and/or surface interests overlying the CO_2 storage volume, cause to be filed by the owners thereof, a Risk Mitigation Covenant in the real property records of each county, parish and other governmental subdivision that maintains real property records showing ownership of and encumbrances on real property in the jurisdictions in which the CO_2 storage volume is located. The Risk Mitigation Covenant shall apply to any activity occurring on the surface or in the subsurface, shall run with the land (including both the surface and subsurface interests), and shall be in a form approved by ACR. Further, the Risk Mitigation Covenant shall prohibit any planned activity that may result in the release of the stored CO_2 (i.e., a reversal) including as a collateral effect of future hydrocarbon, mineral, or water resources development unless measures are taken in advance to compensate for the reversal by replacing the reversed ERTs for ACR's retirement pursuant to a plan acceptable to ACR.

To verify compliance with the terms of the Risk Mitigation Covenant, the Risk Mitigation Covenant shall require that the Project Proponent and the owner of the property notify ACR upon discovery of the occurrence of or plans to conduct any activity that may result in a reversal, shall require that the Project Proponent and owner of the property submit an annual attestation of compliance to ACR, and shall afford ACR an access right to the property in order to conduct inspections. The obligations under the Risk Mitigation Covenant shall be secured by a lien in favor of ACR against the CO_2 and the pore space comprising the CO_2 storage volume, which lien shall be included in the Risk Mitigation Covenant.

In the event that the Project Proponent is not the owner of the pore space comprising and/or surface interests overlying the CO_2 storage volume and is unable to provide the required Risk Mitigation Covenant as part of the demonstration of project eligibility, as an alternative to the Risk Mitigation Covenant ACR may accept (i) proof of the filing of a notice or memorandum of agreement in a form acceptable to ACR in the real property records of each county, parish and other governmental subdivision that maintains real property records showing ownership of and encumbrances on real property in the jurisdictions in which the CO_2 storage volume is located that provides notice of the following terms of the Project Proponent's agreement with such pore space and/or surface interest right owners to any future owners: (a) the agreement that no planned activity shall be conducted that would result in a reversal unless measures are taken in advance to compensate for the reversal by replacing the reversed ERTs for ACR's retirement pursuant to a plan acceptable to ACR (b) the agreement to notify ACR upon discovery of the occurrence of a reversal; and (c) a right of access by Project Proponent or its assigns, including ACR, for access to conduct inspections; or (ii) another risk mitigation measure intended to prevent, provide for the discovery of, and compensate for intentional reversals that is acceptable to ACR.

The Risk Mitigation Covenant or alternative risk mitigation assurance shall be approved by ACR and, as applicable, filed in all required jurisdictions, with a copy of the filed documents provided to ACR prior to the issuance of any ERTs for the GHG project other than ERTs subject to Invalidation. If a Project Proponent does not provide a Risk Mitigation Covenant or an alternative risk mitigation assurance as described above, the ERTs issued by ACR for the project shall be subject to Invalidation; provided however, ERTs subject to Invalidation may be exchanged for ERTs that are not subject to Invalidation in the event the Project Proponent provides ACR with a Risk Mitigation Covenant or alternative risk mitigation assurance satisfying the requirements of this Section 5.4.1.

The obligations of the Project Proponent and any pore space or surface owner under the Risk Mitigation Covenant or alternative risk mitigation assurance shall cease upon demonstration to the reasonable satisfaction of ACR, as evidenced by a written acknowledgement by ACR, that the federal government or the applicable state government has assumed ownership of and monitoring responsibility for the stored CO_2 by the Project Proponent. Any pore space or surface owner shall be relieved of intentional reversal mitigation requirements for any intentional reversal occurring after such government assumption. ACR's written acknowledgement shall be in recordable form and may be filed in the applicable real property records by the Project Proponent or any pore space or surface owner to evidence the termination of the Risk Mitigation Covenant or alternative risk mitigation assurance.

5.3.1.6 QUANTIFICATION OF ATMOSPHERIC LEAKAGE

The project monitoring plan shall include a strategy for quantifying any atmospheric leakage of CO_2 from the storage volume. In the event that leaks from the storage volume occur, which are not remediated in time to prevent atmospheric leakage, Project Proponents shall quantify the CO_2 emissions on a site-by-site basis, according to a reasonable engineering approach. This shall involve computations that incorporate a range of information about the specific geologic reservoir, the CO_2 injection regime, modeling assumptions, and other variables. The project operator has the best knowledge of site-specific conditions and shall combine this knowledge with sound engineering practices to estimate atmospheric leakage, should it occur. This includes the use of conservative factors and algorithms in their estimates. Further, the uncertainty in the estimated value shall be calculated and included in the estimates. In the event of containment failure, a simplified estimation to conservatively determine maximum leakage can be used, rather than requiring rigorous quantification.

5.3.2 MRV Plan Reporting Requirements

Besides the normal GHG Project Plan reporting requirements specified by ACR, CCS projects shall also include a site-specific MRV plan, which is subject to independent third-party validation by a CCS expert on the VVB team (see below). The requirements in the MRV are compatible with local, provincial/state, and federal requirements in Canada and the US. The plan shall include:

- Description of the reservoir where CO_2 is injected.
- Description of model, including key model parameters and their risks and uncertainties, potential failure scenarios evaluated, and simulation results to determine the extremities of the storage volume that is expected to contain the injected CO_2 through the end of the Project Term.
- Site characterization of the storage volume, including identification of potential leakage pathways and any remediation activities undertaken to reduce potential for leakage.
- Monitoring strategy, including monitoring procedures,equipment, and frequency. A range of expected values for monitored parameters that indicate normal operation and that containment is successful. Note: there may be changes to monitoring strategy as the injection proceeds and new technologies become available. The Project Proponent shall document and report changes and the revisions shall be subject to review by the VVB at the next verification interval or next validation (in the case of Crediting Period renewal), whichever comes first.
- If leakage is detected, remedial actions taken to rectify the source of leakage, and/or estimates of atmospheric leakage and how it was mitigated.

It is required that the project specific MRV Plan be developed by a professional with demonstrated experience and knowledge of design and implementation of systems for monitoring geologic storage of CO_2, along with expertise in an earth science discipline relevant to monitoring, such as reservoir engineering, geophysics, geology, hydrology, geomechanics, geochemistry, or other relevant discipline. Demonstrated experience/knowledge shall be evidenced by at least three years' experience in monitoring of CO_2-storage projects, and/or by published, relevant peer-reviewed academic research on monitoring of CO_2 storage. The curriculum vitae of this professional will be reviewed by ACR and the VVB to confirm that they meets the above requirements.

5.3.3 MRV Plan Validation and Verification Requirements

Validation of the MRV plan shall be conducted by a competent third-party Validation and Verification Body (VVB) with in-house or subcontracted CCS expertise meeting the requirements below. The VVB shall determine the adequacy of the MRV plan to meet the storage goals. It includes verification of the model used; model parameters, assumptions, and uncertainties; failure scenarios evaluated; and the adequacy of the monitoring strategy to detect leakage out of the storage volume. The VVB shall also review the proponent's injection permits and verify that the site remained in compliance during the reporting year. In instances of non-compliance, the VVB shall determine whether it affects the ERs claimed and the potential to affect future ERs or compromise long-term storage. The review shall also include a comparison of the MRV Plan with existing protocols and regulations.

The project specific MRV Plan must be independently validated by a professional with demonstrated experience and a high degree of knowledge of design and implementation of systems for monitoring geologic storage of CO_2, along with expertise in an earth science discipline relevant to monitoring, such as reservoir engineering, geophysics, geology, hydrology, geomechanics, geochemistry, or other relevant discipline. Demonstrated experience/knowledge shall be evidenced by at least three years' experience in monitoring of CO_2-storage projects, and/or by published, relevant peer-reviewed academic research on monitoring of CO_2 storage.

This professional shall be an independent third party serving as part of the VVB team. They may be a subcontractor to the VVB as long as the VVB accepts full responsibility for their work through their role as signatory of all validation and verification opinions. They shall be subject to the VVB's project-specific Conflict of Interest evaluation.

The project specific MRV Plan must be approved by this professional at the time of initial validation. Subsequent verifications must also be reviewed by this professional, or a professional meeting the same qualifications, to ensure that the project specific MRV Plan is being adhered to in every reporting period when credits are claimed. Subsequent validations (on Crediting Period renewal every ten years) shall also include review by this professional, or a professional meeting the same qualifications, of any changes to the MRV Plan.

The validation of the initial MRV Plan and subsequent validations and verifications must also be signed off by a registered Professional Engineer (PE) or Professional Geologist (PG), who may be (but is not required to be) the same individual as the professional described above.

5.4 DATA AND ANALYSIS FOR VERIFICATION

This section provides information about specific parameters that shall be monitored to calculate GHG emission reductions from a CCS project according to the quantification procedures in Section 4.0. Project Proponents shall incorporate this information into their project specific MRV Plan and adapt it to accommodate the specific conditions associated with their CCS project.

To ensure the validity of GHG reduction claims, data collection and monitoring is essential. Table 7 aggregates the specific monitoring parameters and activities needed for a comprehensive assessment of the GHG reductions that might be claimed by a Project Proponent. Project Proponents shall consider the location, type of equipment and frequency of measurement for each variable.

In addition to the parameters in Table 7, project proponents shall report the results of the MRV measurements discussed in Section 5.3.

The project site must remain in compliance with its permit conditions through the injection monitoring period. Site operators shall produce documentation indicating that their site has been in regulatory compliance. If there are periods of non-compliance then the date(s) and nature of non-compliance, remedial actions taken, and the date(s) when the site returns to compliance shall be documented and provided during verification. If there are periods of non-compliance, then the effect of non-compliance on the quantified emission reductions shall be evaluated and, if necessary, the creditable emission reductions shall be reduced.

Table 7: Monitoring Parameters[47]

PARAMETER	DESCRIPTION	UNITS	CALCULATED [C], MEASURED [M], OPERATING RECORDS [O]	MEA-SUREMENT FRE-QUENCY	COMMENT
PROJECTION-BASED BASELINE					
Vol. $_{Gas\ Produced}$	Total volume of gas (containing CO_2 and other compounds) produced from the primary process in the project condition, metered continuously at a point immediately downstream of the primary process, measured at standard conditions, in year y.	m^3/yr, scf/yr	[m]	Continuous	Continuous measurement of the volume of gas produced from the primary process, where continuous measurement is commonly defined as one measurement every 15 minutes or less. Flow meters shall be calibrated quarterly or according to manufacturer specifications if more frequent calibrations are recommended by the manufacturer.
$\%CO_2$	%CO2 in the gas stream from the primary process in the project condition, measured immediately downstream of the primary process, in each year.	$\%CO_2$ by volume	[m]	Monthly	Direct measurement of the composition of the gas stream on a monthly basis. Gas analyzers shall be calibrated in accordance with manufacturer's specifications.

[47] Based on A Greenhouse Gas Accounting Framework for Carbon Capture and Storage Projects, Center for Climate and Energy Solutions, February 2012.

PARAMETER	DESCRIPTION	UNITS	CALCULATED [C], MEASURED [M], OPERATING RECORDS [O]	MEA-SUREMENT FRE-QUENCY	COMMENT
STANDARDS-BASED BASELINE					
Output	Units of output from the CO_2 capture facility (e.g., MWh) in the project condition in year **y**.	Units of output (e.g., MWh)	[m]	Daily	Measurement based on the type of primary process. Output shall be measured to account for the total output from the primary process that would have occurred in the absence of the project. Measurement devices shall be calibrated in accordance with manufacturer's specifications.
NON-CAPTURED CO_2 EMISSIONS FROM THE PRIMARY PROCESS					
$Vol._{Gas\ Produced}$	Total volume of gas (containing CO_2 and other compounds) produced from the primary process, metered continuously at a point immediately downstream of the primary process, measured at standard conditions, in year **y**.	m^3/yr, scf/yr	[m]	Continuous	Continuous measurement of the volume of gas produced from the primary process, where continuous measurement is commonly defined as one measurement every 15 minutes or less. Flow meters shall be calibrated quarterly or according to manufacturer specifications if more frequent

PARAMETER	DESCRIPTION	UNITS	CALCULATED [C], MEASURED [M], OPERATING RECORDS [O]	MEASUREMENT FREQUENCY	COMMENT
					calibrations are recommended by the manufacturer.
$\%CO_2$	$\%CO_2$ in the gas stream from the primary process, measured immediately downstream of the primary process, in year **y**. $\%CO_2$ in the captured gas stream, measured at the input to the pipeline, in year **y**.	$\%CO_2$ by volume	[m]	Monthly	Direct measurement of the composition of the gas stream on a monthly basis Gas analyzers shall be calibrated in accordance with manufacturer's specifications.
$Fuel_i$	Volume or mass of each type of fuel, by fuel type **i**, burned by combusted by the primary process in year **y**.	Liters, gallons, m^3, scf, metric tons	[m], [o]	Daily or monthly	For gaseous fuels, daily measurement of the gas flow rate. Flow meters used to measure the volume of gas shall be calibrated according to manufacturer specifications. For liquid and solid fuels monthly reconciliation of purchasing records and inventory adjustments as needed. For liquid and solid fuels, volume or mass measurements are commonly made upon purchase or delivery of the fuel. Reconciliation of purchase receipts

PARAMETER	DESCRIPTION	UNITS	CALCULATED [C], MEASURED [M], OPERATING RECORDS [O]	MEA-SUREMENT FRE-QUENCY	COMMENT
					or weigh scale tickets are an acceptable means to determine the quantities of fossil fuels consumed to operate the CCS systems.
$Vol._{Gas\ Transferred}$	Volume of gas (containing primarily CO_2) captured and input into the pipeline, metered at the point of transfer with the pipeline (or equivalent), measured at standard conditions, in year **y**.	m^3/yr, scf/yr	[m]	Continuous	Continuous measurement of the volume of gas captured from the primary process and input into the pipeline, where continuous measurement is commonly defined as one measurement every 15 minutes or less.
STATIONARY COMBUSTION EMISSIONS FOR CO_2, CH_4, AND N_2O					
$Fuel_i$	Volume of each type of fuel, by fuel type **i**, used to operate each component (capture, transport, and storage) of the CCS project in year **y**.	m^3, scf, Liter, gallons, metric tons	[m], [o]	Daily, monthly	For gaseous fuels, daily measurement of the gas flow rate. Flow meters used to measure the volume of gas shall be calibrated according to manufacturer specifications. For liquid and solid fuels monthly reconciliation of purchasing records and inventory adjustments as needed.

PARAMETER	DESCRIPTION	UNITS	CALCULATED [C], MEASURED [M], OPERATING RECORDS [O]	MEA-SUREMENT FRE-QUENCY	COMMENT
					For liquid and solid fuels, volume or mass measurements are commonly made upon purchase or delivery of the fuel. Reconciliation of purchase receipts or weigh scale tickets are an acceptable means to determine the quantities of fossil fuels consumed to operate the CCS project.
INDIRECT CO_2 EMISSIONS FROM PURCHASED AND CONSUMED ELECTRICITY, STEAM, HEAT					
Electricity	Metered electricity usage from equipment used to operate electrically driven component (capture, transport, and storage) in the CCS project in year **y**.	MWh	[m], [o], [c]	Continuous or monthly	Continuous measurement of electricity consumption or monthly billing records from utility supplier, or reconciliation of maximum kW rating for each type of equipment and operating hours. Electricity meters shall be calibrated by an accredited party per manufacturer's specifications. Electricity consumption shall be metered continuously wherever possible for the CCS project. However, in certain cases other loads may be tied into the same electricity meter and estimates may be required. In these cases, the maximum kW rating of each

PARAMETER	DESCRIPTION	UNITS	CALCULATED [C], MEASURED [M], OPERATING RECORDS [O]	MEA-SUREMENT FRE-QUENCY	COMMENT
					piece of equipment could be used in conjunction with a conservative estimate of operating hours (e.g., 8760 hours per year) to estimate the electricity consumption. Electricity usage can also be determined from monthly bills received from the utility.
Total Fuel Cogen	Total volume or mass of each type of fuel, by fuel type **i**, combusted by the third-party cogeneration unit supplying electricity or thermal energy to the CO_2 capture and compression facilities in year **y**.	Liters, gallons, m^3, scf, metric tons	[m], [o]	Daily, monthly	Daily metering of gaseous fuels or monthly reconciliation of volumes or masses for liquid or solid fuels purchased and in storage.
Heat CCS Project	Quantity of thermal energy purchased from the third-party cogeneration unit to operate the CO_2 capture facilities in year **y**.	MWh	[m], [o]	Daily or monthly	Daily metering of thermal energy sales/purchases to/for the CCS project using a utility meter. Monthly billing received from the cogeneration operator showing the quantity and condition of steam can be used to determine steam usage.

PARAMETER	DESCRIPTION	UNITS	CALCULATED [C], MEASURED [M], OPERATING RECORDS [O]	MEA-SUREMENT FRE-QUENCY	COMMENT
					Steam meters, or similar, shall be calibrated by an accredited party per manufacturer specifications.
Electricity CCS Project	Quantity of electricity purchased from the third-party cogeneration unit to operate the CO_2 capture and compression facilities in year **y**.	MWh	[m], [o]	Daily or monthly	Daily measurement of electricity sales/purchases to/for the CCS project. Monthly billing from the cogeneration operator can be used to determine electricity usage. Electricity meters shall be calibrated by an accredited party per manufacturer's specifications.
Heat Cogen	Total quantity of process energy (e.g., process steam) generated by the third-party cogeneration unit in year **y**.	MWh	[m], [o]	Daily or monthly	Daily metering of total process energy generated using a utility meter. Steam meters, or similar, shall be calibrated by an accredited party per manufacturer's specifications. Cogen operator's monthly records can be used as source of data.
Electricity Cogen	Total quantity of electricity generated by the third-party cogeneration unit in year **y**.	MWh	[m], [o]	Daily or monthly	Daily measurement of total electricity sales/purchases. Electricity meters shall

PARAMETER	DESCRIPTION	UNITS	CALCULATED [C], MEASURED [M], OPERATING RECORDS [O]	MEASUREMENT FREQUENCY	COMMENT
					be calibrated by an accredited party per manufacturer's specifications. Cogen operator's monthly records can be used as source of data.
VENTED AND FUGITIVE CO_2 EMISSIONS FROM CO_2 TRANSPORT – MASS BALANCE					
$Vol._{Gas\ Received}$	Volume of gas (containing primarily CO_2) captured and input into the pipeline, metered at the point of transfer with the pipeline (or equivalent), measured at standard conditions, in year **y**.	m^3/yr, scf/yr	[m]	Continuous	Continuous measurement of the volume of gas captured from the primary process and input into the pipeline, where continuous measurement is commonly defined as one measurement every 15 minutes or less. Flow meters shall be calibrated quarterly or according to manufacturer specifications if more frequent calibrations are recommended by the manufacturer.
$\%CO_2$	**$\%CO_2$** in the gas stream being transported by pipeline, measured at the input to the pipeline, in year **y**.	$\%CO_2$ by volume	[m]	Monthly	Direct measurement of the composition of the gas stream on a monthly basis. Gas analyzers shall be calibrated in accordance with manufacturer's specifications.

PARAMETER	DESCRIPTION	UNITS	CALCULATED [C], MEASURED [M], OPERATING RECORDS [O]	MEA-SUREMENT FRE-QUENCY	COMMENT
$Vol._{Gas\ Supplied}$	Total volume of gas (containing primarily CO_2) supplied to the storage site operator, metered at the point of transfer between pipeline (or equivalent) and CO_2 storage site, measured at standard conditions, in year **y**.	m^3/yr, scf/yr	[m]	Continuous	Continuous measurement of the volume of gas delivered to the CO_2 storage site, where continuous measurement is commonly defined as one measurement every 15 minutes or less. Flow meters shall be calibrated quarterly or according to manufacturer specifications if more frequent calibrations are recommended by the manufacturer.
VENTED AND FUGITIVE CO_2 EMISSIONS FROM CO_2 STORAGE					
$N_{Blowdown\ i}$	Number of blowdowns (venting events) from specific equipment at the storage site (e.g., compressors, pressure release valves), obtained from blowdown event logs retained by storage site operator.	#	[o]	NA	Storage site operator shall keep detailed logs of all venting incidents.
$V_{Blowdown\ i}$	Total volume of blowdown equipment chambers for equipment (including pipelines,	m^3, scf	[o], [c]	NA	Volume can be estimated based on equipment specifications (pipeline diameters etc.), flow meters, duration of event.

PARAMETER	DESCRIPTION	UNITS	CALCULATED [C], MEASURED [M], OPERATING RECORDS [O]	MEASUREMENT FREQUENCY	COMMENT
	manifolds, and vessels between isolation valves).				
$\%GHG_j$	Concentration of GHG (CO_2 or CH_4) in the injected or produced gas (volume percent CO_2 or CH_4, expressed as a decimal fraction).	%	[m]	Monthly	Direct measurement of the composition of the gas stream on a monthly basis. Gas analyzers shall be calibrated in accordance with manufacturer's specifications.
$Count_s$	Total number of each type of emission source at the injection wellheads and at surface facilities located between the point of transfer from the CO_2 pipeline and the injection wells in the formation.	#	[o]	NA	Storage site operator shall develop and maintain an equipment inventory to identify all possible fugitive emission sources from surface facilities at the storage site.
T_s	Total time in hours that the equipment associated with each fugitive emission source was operational.	Hours	[o]	NA	Estimated based on operational records of downtime at the injection wells, storage site and hydrocarbon production facilities.
$Vol._{Gas\ Sold}$	Volume of natural gas or fuel gas, produced from the formation that CO_2 is being injected into, that is sold to	m^3, scf	[m]	Daily	Continuous metering of sales volumes of natural gas.

PARAMETER	DESCRIPTION	UNITS	CALCULATED [C], MEASURED [M], OPERATING RECORDS [O]	MEA-SUREMENT FRE-QUENCY	COMMENT
	third parties or input into a natural gas pipeline in year **y**.				
$\%CO_{2\ Gas\ Sold}$	**$\%CO_2$** in the natural gas or fuel gas that is sold to third parties or input into a natural gas pipeline, in year **y**.	%	[m]	Annual	Direct measurement of the composition of the natural gas at the sales meter.
$Mass_{Water\ Prod}$	Mass of water produced from the formation that CO_2 is being injected into, that is disposed of or otherwise not-re-injected back into the formation.	Metric tons	[o]	Monthly	Monthly reconciliation of water disposal records.
$Mass\ Frac_{CO2\ in\ Water}$	Mass fraction of CO_2 in the water produced from the formation.	-	[m]	Annual	Conduct lab analysis of composition of produced water. Report dissolved inorganic carbon species.
$Mass_{Oil\ Prod}$	Mass of crude oil and other hydrocarbons produced from the formation into which CO_2 is being injected.	Metric tons	[m]	Monthly	Reconciliation of hydrocarbon sales from facilities associated with the producing formation.
$Mass\ Frac_{CO2\ in\ Oil}$	Mass fraction of CO_2 in the crude oil and other	-	[m]	Annual	Conduct lab analysis of composition of crude oil

PARAMETER	DESCRIPTION	UNITS	CALCULATED [C], MEASURED [M], OPERATING RECORDS [O]	MEA-SUREMENT FRE-QUENCY	COMMENT
	hydrocarbons produced from the formation.				
CO_2 TRANSFERRED OFFSITE					
$Vol_{CO2\_Transfer}$	Volume of produced CO_2 from an EOR operation transferred outside project boundary in each year.	m^3, scf	[m]	Monthly	Projects Proponent shall deduct from quantified reductions "produced CO_2" that is not reinjected but transferred offsite. Measured at a point to account for total volume not reinjected.
ATMOSPHERIC LEAKAGE OF CO_2 FROM STORAGE					
CO_{2_Z}	Total mass of CO_2 emitted through leakage pathway **z** to atmosphere in year **y**.	Metric tons	[c]	NA	If leakage from the geologic reservoir to the atmosphere occurs, the mass of CO_2 that has escaped would be estimated based on monitoring and measurements completed as part of the CCS project's MRV plan. **NOTE**: This does not include fugitive CO_2 emissions from wells, which are calculated according to Equation 26.

EMISSIONS FROM PRODUCED HYDROCARBONS

$PE_{Production_y}$	Transportation, refining, and end use emissions from produced hydrocarbons (tCO_2/yr).	Metric tons	[c]	Annual	Emissions from produced oil transportation, refining, and end-use shall be considered project emissions.
$PE_{Transportation}$	CO_2e emissions from transportation of produced oil.	Metric tons	[c]	Annual	Emissions from transportation of crude and refined oil.
$PE_{Refining}$	CO_2e emissions from refining of produced oil.	Metric tons	[c]	Annual	Emissions from refining oil based on API gravity of produced oil.
$PE_{End\ Use}$	CO_2e emissions from end use of produced oil.	Metric tons	[c]	Annual	Emissions from end use of oil, usually combustion.

6 EMISSIONS OWNERSHIP AND QUALITY

6.1 STATEMENT OF DIRECT EMISSIONS

The Project Proponent shall attest annually that all emission reductions occur on the property owned and/or controlled by the Project Proponents and that none of the emission reductions claimed by the project are indirect emissions.

6.2 MEASUREMENT TECHNIQUES

Volumetric flow rates will be quantified by commercially available devices that measure the mass or volumetric rate of flow of a gas or liquid moving through an open or closed conduit. Flow meters include, but are not limited to, rotameters, turbine meters, coriolis meters, orifice meters, ultra-sonic flow meters, and vortex flow meters. The devices shall be installed and calibrated in accordance with manufacturer's specifications. The flow meter will be operated in accordance with an appropriate standard method published by a consensus-based standards organization if such a method exists or an industry standard practice. The specific standard used shall be documented and reported. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB). Flow meter calibrations performed shall be National Institute of Standards and Technology (NIST) traceable.

Gas or liquid composition analysis shall be measured by an appropriate standard method published by a consensus-based standards organization, if such a method exists, or an industry standard practice.

Flowrate measurements are made continuously, where continuous measurement is commonly defined as one measurement every 15 minutes or less. The CO_2 concentration in the gas stream shall be measured at monthly intervals.

Monitoring methods for MRV of geologic storage sites are discussed in USDOE and USEPA documents and are also contained in certain State regulations.[48, 49, 50, 51]

6.3 OFFSET TITLE

Since CCS projects involve capture, transport, and sequestration processes, which are often conducted by different companies, the ownership to the title of CO_2 credits associated with the project's emission reductions must be clearly defined. This can be done through contracts among the parties in which one of the companies has clear ownership of the credits.

During the operational phase, documentation that traces the chain of custody of CO_2 as it is transferred from parties involved in the capture, transport, and sequestration processes shall be established. This includes documents indicating the date (month/yr), CO_2 volumes transferred by the supplier, transported, and received by the sequestration operator. The documentation shall be maintained by the Project Proponent and provided during verification. The documents shall be retained for a minimum period of three years following the end of the crediting period.

6.4 PERMANENCE, LIABILITY, AND MITIGATION

For CCS projects, Project Proponents must demonstrate that the CO_2 captured and stored is permanently sequestered underground. The post-injection monitoring tasks as described in Section 5.3 will be conducted for the Project Term defined in Section 2.2. Post-Project Term requirements are described in Section 5.3.1. Site characterization coupled with the use of site-specific monitoring and modeling provides data and information for the operator to calibrate, validate and compare the model over the Project Term. This model will be used as a predictive tool to monitor and track the CO_2 plume during the post-injection period and beyond. The predictions will be confirmed by measurements of pressure and/or other relevant parameters made during the remainder of the Project Term (post-injection phase). As indicated in , no leakage is assured when it can be verified that no migration of injected CO_2 is detected across

[48] Best Practices for: Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations, DOE/NETL-311/081508, January 2009, https://www.globalccsinstitute.com/archive/hub/publications/159708/best-practices-monitoring-verification-accounting-co2-stored-deep-geologic-formations.pdf

[49] Best Practices for: Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations – 2012 Update, DOE/NETL-2012/1568, October 2012, https://www.netl.doe.gov/sites/default/files/2018-10/BPM-MVA-2012.pdf

[50] General Technical Support Document for Injection and Geologic Sequestration of Carbon Dioxide: Subparts RR and UU Greenhouse Gas Reporting Program, (Chapter 4 & 5), USEPA, (2010) https://www.epa.gov/sites/production/files/2015-07/documents/subpart-rr-uu_tsd.pdf

[51] Fluid Injection in Productive Reservoirs, Texas Administrative Code (TAC), Title 16, Part 1, RULE §3.46

the boundaries of the storage volume and the modeled failure scenarios all indicate that the CO_2 will remain contained within the storage volume.

An operator shall prove financial responsibility prior to gaining a permit to begin active injection operations. This effort establishes a plan for safe operation of injection activities. Implementation of this safety plan throughout operations should mitigate long-term liabilities. Pore space ownership laws may vary by jurisdiction. Project proponents are responsible for demonstrating that they are compliant with all local rules and regulations related to liability and pore space.

Long-term liabilities arise from migration of the CO_2 plume, either vertically through well bores, fractures, or faults or horizontally by moving to points of leakage. Over time, project uncertainties can be greatly reduced through a well-designed monitoring program. As uncertainties are addressed and reduced, confidence in the location of CO_2 plume in the reservoir increases over years of MRV operations. Migration of CO_2 plumes might qualify as trespass or nuisance under State law. The oil industry has addressed this liability during EOR, and the issue of trespass has been addressed in a Texas case (Texas Railroad Commission v. Manziel),[52] which held that injection associated with a state-authorized secondary recovery project would not cause trespass even though fluids move across property lines. In other jurisdictions, this issue would be dependent on individual State regulations and statutes. While the lateral migration of CO_2 outside the original project boundaries could indicate that modifications to the project's MRV are necessary, these events should not disqualify or affect the project's emission reductions as long as there is no leakage to the atmosphere.

If a CO_2-sequestration project has a leak which causes damage, the operating Company may be liable in criminal or civil courts. Case law has built up around claims associated with subsurface injection and liabilities can be managed through the existing legal system. To cover liability of atmospheric leakage, Project Proponents can purchase private insurance designed to cover damages associated with releases, including third-party liability and liability to ACR, and those resulting from lost credits due to reversals. Insurance premiums would be paid by the Project Proponent to the insurance company, and, in the event of CO_2 leakage to the atmosphere, the insurance company would cover obligations to compensate for reversals in GHG emissions reductions (e.g., purchase and retire ERTs).

In lieu of insurance, Project Proponents may opt to create an ERT Reserve Account. Each year the Project Proponent would deposit 10 (ten) percent of the project's ERTs in the Reserve Account. In the event of reversals, a debit shall be measured and reported, verified, and reconciled by the Account by retiring ERTs from the Reserve Account. To provide flexibility, contributions to the Reserve Account need not come from the project itself whose risk is being mitigated. A Project Proponent may make its contribution in ERTs of any type and vintage.

If atmospheric leakage occurs, remediation will be conducted in accordance with the site-specific remediation plan, and any leaks to the atmosphere shall be estimated and mitigated.

[52] Railroad Commission of Texas v. Manziel, 361 S.W. 2d 560 (Tex. 1962)

The procedures for mitigation of atmospheric leakage during the injection and post-injection periods are summarized in Table 8. If a small release (i.e., less than the estimated ERs for that year) occurs during the injection period and results in leakage to the atmosphere, then it shall be mitigated as project emissions in the same year using Equation 30. If the release is large and exceeds the ERs for that year, then a portion of that release is mitigated as project emissions until ERs for that year are zero. The remaining release (i.e., unreconciled quantity) shall be compensated by liability insurance, or be reconciled through the retirement of an equivalent quantity of ERTs from the project's ERT Reserve Account.

Table 8: Atmospheric Leakage Mitigation Procedures

ATMOSPHERIC LEAKAGE SCENARIO	REQUIRED MITIGATION
PROJECT TERM	
INJECTION PERIOD Leakage detected in year "y" where $y \leq n$ "n" = total years of injection	Handle as project emissions in year y using Equation 30. If leakage exceeds year y ERs, then reconcile as project emissions in year y until emissions reductions equal zero and excess leakage (i.e., unreconciled leakage) is mitigated by one of the following options: 4. Use private insurance acceptable to ACR (see note), or 5. Upon ERT issuance, contribute 10 % of the project's ERs/year or an equivalent quantity of ERTs (of any type and vintage) into an ERT Reserve Account; ACR will retire quantity to be mitigated from the Account.
POST INJECTION PERIOD Leakage detected in year "y" where $y > n$. "n" = total years of injection	Project Proponent shall choose one of the following options: 6. Use private insurance acceptable to ACR (see note), or 7. Upon ERT issuance, contribute 10 % of the project's ERs/year or an equivalent quantity of ERTs (of any type and vintage) into an ERT Reserve Account; ACR will retire quantity to be mitigated from the Account.
POST PROJECT TERM	
A release of stored CO_2 that is intentional or that is a collateral effect of planned activities that affect the storage volume	Per the Risk Mitigation Covenant or an alternative risk mitigation assurance approved by ACR, prior to any release of stored CO_2 as described in the Covenant, ACR must be compensated through replacement deposit of the full amount of ERTs issued to the project during the Project

ATMOSPHERIC LEAKAGE SCENARIO	REQUIRED MITIGATION
	Term, allowing ACR to retire such ERTs. If an intentional or collateral release occurs for a project with ERT's subject to Invalidation, ACR may invalidate such ERTs if replacement ERTs are not deposited for retirement by ACR.

NOTE: Any private insurance policy must be evaluated and approved by ACR to make sure there are no exclusions, term limitations, or liability limits that leave ACR exposed. Only once ACR accepts the insurance product will ACR waive contributions to the ERT Reserve Account.

If atmospheric leakage occurs during the post-injection period, then the Project Proponent shall mitigate the leaked quantity by liability insurance or by the retirement of an equivalent quantity of ERTs from the project's ERT Reserve Account.

Project Proponents shall indicate their mitigation strategy (i.e., insurance or ERT Reserve Account) in their GHG Project Plan. If Project Proponents choose to mitigate by insurance, then that insurance product must be approved by ACR as indicated in Table 8. If Project Proponents choose to mitigate by contributions to an ERT Reserve Account, those contributions shall begin from the start of ERT crediting and shall constitute 10% of the project's ERs each issuance, or an equivalent quantity of ERTs (of any type and vintage).

In the event that atmospheric leakage exceeds the ERT Reserve Account contributions or the coverage provided by insurance, the Project Proponent shall mitigate any unreconciled quantity through deposit of sufficient ERTs for ACR's retirement (of any type or vintage). If the Project Proponent does not deposit sufficient ERTs to mitigate the leakage within 45 days, then ACR retains the right to freeze the Proponent's project account and retire any existing ERTs to mitigate the unreconciled quantity.

6.5 PORE SPACE OWNERSHIP

CCS Project Proponents may need to own or obtain rights to the subsurface pore space where CO_2 will be injected and sequestered. Project Proponents, third party verifiers, and ACR must have access to the site throughout the project lifetime including post-injection monitoring. Project Proponent must also demonstrate that the CO_2 in the reservoir will be left undisturbed in perpetuity. In the U.S., with the exception of federal lands, the acquisition of storage rights, which are considered property rights, generally is a function of State law. In many States, no clear property right to use pore space has been assigned to surface property owners covering the permanent injection of fluids into deep geological formations. Such injection under the Class II UIC program can occur without approval from surface landowners except for those on whose property the injection well is located. These projects appear to have adopted the "inverse rule of capture" rule that allows project owners to be held non-liable if their injected fluids trespass into the subsurface of neighboring properties as long as their injection was in accordance with a federal or state-approved program. In effect the subsurface rights vest in whoever is able to assert them physically on a first-come basis.[53]

Pore space ownership issues are beginning to be addressed through State law and regulation, those laws are not uniform. In the case of storage in non-EOR projects, some states, including Montana, Wyoming, and North Dakota, have assigned pore space ownership to the surface owners. In Wyoming and Montana, pore space ownership may be severed and assigned to the mineral owner. In Texas, mineral rights are severed from surface rights and there is no clear ownership of pore space between surface and mineral owners; although, it is likely that pore space is owned by surface owners. In the cases where mineral rights are severed from surface rights, it is likely that project proponents will need agreements with both parties in order to inject CO_2.

In the case of CO_2 EOR projects, the right to inject CO_2 into the subsurface oil reservoir generally is contained in and part of the oil and gas lease that would have been obtained to develop the project. Therefore, the right to use an oil reservoir for the associated storage of CO_2 during the operational phase of a CO_2 EOR project would most likely be permissible under an oil and gas lease. Once injected and secured in the reservoir, the operator is not required to extract the injected CO_2 at the completion of the operational phase of the project.

Migration of any injected fluid is only permissible provided the migration complies with regulations covering injection operations, does not interfere with preexisting mineral recovery operations, cause damage to any adjacent subsurface and overlying surface properties, or endanger public health and safety.

All projects must demonstrate their right or permission to access the site and reservoir to conduct all monitoring requirements in this methodology. In the case of EOR, it is typical that mineral lease rights and associated surface use rights expire following the end of hydrocarbon production activities. However, monitoring after the end of CO_2 injection activities is needed as part of assuring no atmospheric leakage (Section 5.3). Project Proponents shall ensure that EOR operators have continued access to the surface to conduct post-injection monitoring activities and if necessary, remediation. Based on the site-specific monitoring planned for the post-injection period and associated surface access requirements, Project Proponents shall obtain needed surface use rights from the surface owners for the duration of the Project Term. This will usually entail surface use agreements similar to what is currently used to conduct groundwater sampling and remediation activities. Further, as required by Section 5.3.1.5, Project Proponents shall obtain the consent of surface owners to the filing of a Risk Mitigation

[53] Carbon Capture and Sequestration: Framing the Issues for Regulation, CCSReg Interim Report, January 2009

Covenant or provide an alternative risk mitigation assurance acceptable to ACR, and if it does not do so, the ERTs issued for the project shall be subject to Invalidation.

6.6 COMMUNITY AND ENVIRONMENTAL IMPACTS

CCS projects involve the installation of capture technologies, pipelines and gas separation and compression infrastructure. These CCS projects are capital-intensive and may require environmental assessments. If an Environmental Assessment (EA) or an Environmental Impact Statement (EIS) is required, that document or a summary thereof shall be provided to ACR and provided to the VVB on request. There are different state and federal laws, regulations and guidance that require an EA or EIS for certain government actions, such as the federal Environmental Policy Act (NEPA) and state analogues. Project Proponents shall document in the GHG Project Plan a mitigation plan for any foreseen negative community or environmental impacts and shall disclose in their annual Attestations any negative environmental or community impacts or claims of negative environmental and community impacts made during the reporting year. These claims include legal actions and/or other written complaints filed by affected parties.

7 QA/QC

QA/QC procedures shall be implemented during all phases of the project to assure data quality and completeness. The USEPA has published Mandatory Greenhouse Gas Reporting requirements for various types of facilities that emit GHG.[54] General Provisions are contained in Subpart A. This methodology incorporates the requirements contained in Part 98.3(i) of Subpart A, *Calibration Accuracy Requirements*, which requires all measurement devices be calibrated according to the manufacturer's recommended procedures or an appropriate industry consensus standard to an accuracy of 5 percent. Calibration records shall be maintained and made available to third party verification.

For flow meters, all calibrations shall be performed at measurement points that are representative of normal operation of the meter. Except for the orifice, nozzle, and venturi flow meters (which are described in the next paragraph of this section), the calibration error at each measurement point is calculated using Equation 33. The terms ''R'' and ''A'' in Equation 33 must be expressed in consistent units of measure (e.g., gallons/minute, ft^3/min). The calibration error at each measurement point shall not exceed 5.0 percent of the reference value.[55]

Equation 33: Calibration Error Calculation for Flow Meters

$$\mathbf{CE} = \frac{(\mathbf{R} - \mathbf{A})}{\mathbf{R}} \times \mathbf{100}$$

WHERE

CE	Calibration Error (%)
R	Reference Value
A	Flow meter response to the reference value.

For orifice, nozzle, and venturi flow meters, the initial quality assurance consists of in-situ calibration of the differential pressure (delta-P), total pressure, and temperature transmitters. Each transmitter shall be calibrated at a zero point and at least one upscale point. Fixed reference points, such as the freezing point of water, may be used for temperature transmitter calibrations. The calibration error of each transmitter at each measurement point is calculated using Equation 34. The terms ''R'', ''A'', and ''FS'' in Equation 34 must be in consistent units of measure (e.g., milliamperes, inches of water, psi, degrees). For each transmitter, the CE value at each measurement point shall not exceed 2.0 percent of full-scale. Alternatively, the results

[54] Mandatory Greenhouse Gas Reporting, USEPA Code of Federal Regulations. 40 CFR Part 98
[55] Mandatory Greenhouse Gas Reporting, USEPA Code of Federal Regulations. 40 CFR Part 98.3(i)

are acceptable if the sum of the calculated CE values for the three transmitters at each calibration level (i.e., at the zero level and at each upscale level) does not exceed 5.0 percent.

Equation 34: Calibration Error Calculation for Flow Meter Transmitters

$$\mathbf{CE} = \frac{(\mathbf{R} - \mathbf{A})}{\mathbf{FS}} \times \mathbf{100}$$

WHERE

CE	Calibration Error (%)
R	Reference Value
A	Transmitter response to the reference value.
FS	Full scale value of the transmitter.

Data on gas and liquid stream composition analysis shall include calibrations of the gas analyzer or other instrumentation used. If an outside third-party laboratory is used, documentation of their accreditation to conduct the analysis shall be obtained.

Fuel billing meters are exempted from the calibration requirements, provided that the fuel supplier and any unit combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company (USEPA 40 CFR Part 98.3(i)).

The methodology recommends additional procedures as part of the project's QA/QC program.

Data collection procedures (templates, logs, etc.) shall be developed to ensure site-specific data are collected in a timely fashion. Periodic reviews of the data for accuracy, completeness and consistency shall be conducted. As appropriate these procedures shall be included in the plant and storage site standard operating procedures (SOPs). If data are missing, the methodology recommends that Project Proponents follow missing data procedures contained in USEPA Subpart RR regulations.[56]

The MRV Plan to detect and assess subsurface leakage (if any) shall include quality checks on the data, models, etc. and report on significant deviations from expected values.

The GHG Project Plan shall include a section on QA/QC plan and procedures that will be followed to ensure data quality and completeness.

[56] USEPA Subpart RR, Geologic Sequestration of Carbon Dioxide, 40 CFR Part 98.445, Procedures for Estimating Missing Data.

8 UNCERTAINTIES

The emission reduction calculations in this methodology are designed to minimize the possibility of overestimation and over-crediting of GHG emission reductions, due to various uncertainties, primarily associated with fluid flow and composition analysis of gas and liquid streams, plant operating parameters, and accurate logs of emission leakage events maintained by site operators.

While some of these uncertainties are more easily quantified than others, the sources and relative magnitude of uncertainties (and changes thereof) shall be explicitly addressed and discussed by the Project Proponent and described in the GHG Project Plan as part of the GHG emissions calculation and reporting process.

Potential sources of uncertainty and the associated QA/QC program elements designed to minimize them are summarized in Table 9. Overall uncertainty can be assessed by using the uncertainties of each element in a calculation.

The accuracy and precision of measurement equipment, such as the flow meters, gas composition analyzers, process measurements (e.g., electricity and steam), are readily quantified and the uncertainties associated with each measurement are considered to be low.

The accuracy and completeness of site operator data on blowdown events and estimates of fugitive emission losses depend on meticulous logs maintained by the operator. The uncertainty in these parameters is considered low since site operators are currently required to report these data to the USEPA as part of their reporting requirements under Subpart W.[57] Operators that are exempt from Subpart W reporting shall follow procedures contained in subpart W to estimate losses from blowdown events and fugitive emissions.

The uncertainty in detection and assessment of leakage from the subsurface to the atmosphere is dependent on the design and implementation of a site's MRV Plan. For depleted oil and gas reservoirs and EOR sites, the geologic reservoir at the storage sites is generally well characterized and modeled. For saline formations, there may be less data readily available to characterize the site to the level of detail required, these data will need to be gathered prior to any project review or approvals. The development of a site-specific MRV Plan, that identifies possible leakage pathways and utilizes a proper set of monitoring tools to provide assurance of containment and to detect leakage, should it occur, is critical. There is a wealth of oil and gas industry experience in the design and implementation of proper monitoring tools, many of which

[57] Subpart W – Petroleum and Natural Gas Systems | Greenhouse Gas Reporting Program (GHGRP) | US EPA , states: owners or operators of facilities that contain petroleum and natural gas systems and emit 25,000 metric tons or more of GHGs per year must report emissions from all source categories located at the facility for which emission calculation methods are defined in the rule. It includes the reporting of venting and fugitive emissions from onshore petroleum and natural gas production facilities, such as EOR operations.

are currently being utilized to optimize production. Based on the implementation of a well-designed MRV Plan, the uncertainty in detection and measurement of leakage is considered low.

Table 9: Potential Sources of Uncertainty

DATA PARAMETER	UNCERTAINTY LEVEL OF DATA	COMMENTS
$Vol._{Gas\ Produced}$ $Vol._{Gas\ Transferred}$ $Vol._{Gas\ Received}$ $Vol._{Gas\ Supplied}$ $Vol._{Gas\ Sold\ (fuel)}$ $Vol_{CO2\_Transfer}$	Low	Extensive experience with flow meters used for this application. Flow meters shall be installed and operated in accordance with manufacturer's specifications. Flow meters shall be calibrated quarterly or according to manufacturer specifications if more frequent calibrations are recommended by the manufacturer.
$\%CO_2$ $\%CO_{2\ Gas\ Sold\ (fuel)}$	Low	Industrial processes producing CO_2 are well controlled so minimal variability of CO_2 concentrations in gas stream. Direct measurement of the composition of the gas stream shall be made on a monthly basis. Gas analyzers shall be calibrated in accordance with manufacturer's specifications.
Output	Low	Measurements based on the type of primary process. Output shall be measured using instrumentation that shall be calibrated in accordance with manufacturer's specifications.
$Fuel_i$ Total Fuel Cogen	Low	For gaseous fuels, daily measurement of the gas flow rate. Flow meters used to measure the volume of gas shall be calibrated according to manufacturer specifications. For liquid and solid fuels monthly reconciliation of purchasing records and inventory adjustments as needed. For liquid and solid fuels, volume or mass measurements are commonly made upon

DATA PARAMETER	UNCERTAINTY LEVEL OF DATA	COMMENTS
		purchase or delivery of the fuel. Reconciliation of purchase receipts or weigh scale tickets are an acceptable means to determine the quantities of fossil fuels consumed to operate the CCS
Mass Frac. $_{\text{Carbon i}}$	Low	Direct measurement of the carbon content of the fuel using industry accepted practices.
Electricity Electricity CCS Project Electricity Cogen	Low	Continuous measurement of electricity consumption using meters calibrated by an accredited party per manufacturer's specifications. If third party utility billing records are used, those measurements are usually based on well calibrated meters. If estimated from maximum kW rating for each type of equipment and operating hours, the uncertainty in energy usage is greater, however the estimates will be conservatively higher.
Heat CCS Project Heat Cogen	Low	Daily metering of thermal energy sales/purchases to/for the CCS project using meters calibrated by an accredited party per manufacturer specifications.
$N_{\text{Blowdown i}}$ $V_{\text{Blowdown i}}$	Low	Based on storage site operator's detailed logs of all venting incidents. Volume estimates are based on pipeline diameters and flow conditions and duration of events. Operators are required to log and report these data under federal (USEPA Subpart W) and most State regulations.
%GHG $_j$	Low	Direct measurement of the composition of the gas stream on a monthly basis. Gas analyzers shall be calibrated in accordance with manufacturer's specifications.
Count_s	Low	Storage site operator shall develop and maintain an equipment inventory of all possible fugitive

DATA PARAMETER	UNCERTAINTY LEVEL OF DATA	COMMENTS
T_s		emission sources from surface facilities at the storage site and operational time. Operators are required to report these data to the USEPA per Subpart W requirements.[58]
$Mass_{\text{Water Prod}}$ $Mass_{\text{Oil Prod}}$	Low	Data on water production and injection rates, which are measured with calibrated flow meters, are routinely maintained by operators. Monthly reconciliations of water disposal records are routinely conducted. Oil or other hydrocarbon production values are based on continuous, daily, or monthly measurements. Data can be obtained from reconciliation of oil or other hydrocarbon sales from facilities associated with the producing formation.
$Mass\ Frac_{\text{CO2 in Water}}$ $Mass\ Frac_{\text{CO2 in Oil}}$	Low	Data obtained from periodic lab analysis of produced water and produced oil samples using industry accepted practices.
CO_{2_Z}	Low	CO_2 leakage (if any) from the geologic reservoir to the atmosphere would be estimated based on monitoring and measurements completed per the CCS project's MRV Plan. For oil and gas producing reservoirs that have been extensively characterized, modeled, and monitored considering potential failure scenarios, the uncertainty in detecting and estimating leakage is low.

[58] US Environmental Protection Agency. Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems, Final Rule: Subpart W. November 30, 2010

DEFINITIONS

For additional definitions of standard terms see the latest version of the *ACR Standard*

Atmospheric Leakage	Movement of injected CO_2 from the geologic storage reservoir to the atmosphere.
Carbon Capture and Storage	The separation and capture of carbon dioxide (CO_2) from the atmospheric emissions of industrial processes or the *direct air capture* (DAC) of atmospheric CO_2 and the transport and safe, permanent storage of the CO_2 in deep underground geologic formations.
Carbon Dioxide Removal	CO_2 removal directly from the atmosphere, includes Direct Air Capture with CCS (DACCS) and utilization of bioenergy or biomass in combination with CCS Bioenergy with Carbon Capture and Storage (BECCS) or Biomass with Carbon Removal and Storage (BiCRS).
Confining Zone	Region in the subsurface above the *Storage Volume* that forms a nearly impenetrable layer to the vertical migration of CO_2.
Direct Air Capture	Process of separating and capturing CO_2 from the atmosphere.
Enhanced Oil Recovery	The process of producing hydrocarbons from subsurface reservoirs using thermal, gas, or chemical injection techniques. In this methodology, EOR concerns the injection of CO_2 into a producing oil reservoir.
Excess CO_2 Emissions	Additional CO_2 emissions that could result from poor or negligent operation of the primary process, or from not meeting existing regulations mandating the use of certain technologies, or regulations directly controlling CO_2 emissions or other pollutant emissions which indirectly affect CO_2 emissions. Projects shall not be credited for storage of excess CO_2 emissions.
Fugitive Emissions	Emissions due to leaks from equipment such as flanges, valves, flow meters, headers, etc. These emissions can occur in the capture, transport, injection, and storage segments of the project.

Functional Equivalence	A project and baseline are functionally equivalent if they provide the same function while delivering comparable products in quality and quantity.
Geologic Storage	The placement of CO_2 into a subsurface formation, such as an oil and gas producing reservoir or a deep saline aquifer, where it will remain safely and permanently stored.
Geologic Storage Reservoir/Formation	A three-dimensional confined region in the subsurface that encompasses the entire space that will be occupied by CO_2 in a storage project.
Greenhouse Gas (GHG) Assessment Boundary	The greenhouse gases included in the calculation of baseline and project emissions. In this methodology these include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O).
Invalidation	The voiding of an ERT by ACR. In the event that, and for so long as a Project Proponent has not filed a Risk Mitigation Covenant or provided an alternative risk mitigation assurance acceptable to ACR as described in Section 5.3.1.5, ERTs issued for the project shall be subject to invalidation by ACR in the event of an intentional reversal for which compensation is not made.
Monitoring, Reporting, and Verification (MRV) Plan	A verifiable project-specific plan which includes the monitoring and reporting requirements described in Section 5.3 of this methodology.
Oil and Gas Reservoir	See *Geologic Storage Reservoir/Formation*
Permanence	Permanence refers to the perpetual nature of removal enhancements and the risk of reversal of a project's emissions reductions, i.e., the risk that atmospheric benefit will not be permanent. GHG removals may not be permanent if a project has exposure to risk factors, including unintentional reversals (i.e., atmospheric leakage as defined above) and intentional reversals (e.g., release of stored CO_2 that is intentional or that is a collateral effect of any planned activities affecting the storage volume). For CCS projects, the absence of atmospheric leakage during the Project Term is considered assured when it can be verified that no migration of injected CO_2 is detected across the boundaries of the storage volume and the modeled failure scenarios all indicate that the

	CO_2 will remain contained within the storage volume (see 5.3.1). The risk of intentional reversal is determined by an assurance that the injected CO_2 remains in the storage volume based on the post-injection monitoring strategy and post-Project Term storage requirements described in Section 5.3.
Physical Boundary	GHG emission sources included in the project.
Primary Process	The specific power generation or industrial process (e.g., natural gas processing, hydrogen production, steelmaking) creating the captured CO_2.
Producing reservoir	See *Geologic Storage Reservoir/Formation*
Projection-based Baseline	A baseline that would correspond with the project's actual CO_2 capture site, absent the capture and compression system located at the CO_2 source.
Reversal	Atmospheric leakage of injected CO_2 from the *Storage Volume* that is not remediated.
Reversal Risk Mitigation Mechanism	Project Proponents shall mitigate reversal risk by contributing ERTs from the project itself to the ACR ERT Reserve Account; contributing ERTs of another type or vintage to the ACR ERT Reserve Account; providing evidence of sufficient insurance coverage with an ACR-approved insurance product to recover any future reversal; or using another ACR-approved risk mitigation mechanism. ACR requires geologic sequestration Project Proponents to use approved methodologies that assure permanence including ongoing QA/QC and long-term monitoring and reversal risk mitigation measures as described in Section 5.3.1.5.
Risk Mitigation Covenant	A covenant filed in the real property records of each county, parish and other governmental subdivision that maintains real property records showing ownership of and encumbrances on real property in the jurisdictions in which the CO_2 storage volume is located, prohibiting any intentional reversal (e.g., release of stored CO_2 that is intentional or that is a collateral effect of any planned activities affecting the storage volume) unless measures are taken in advance to compensate for the reversal by replacing the reversed ERTs for ACR's retirement pursuant to a plan acceptable to ACR. See Section 5.3.1.5.

Standards-based Baseline	A baseline represented by a performance or regulatory standard, usually expressed in the form of an intensity metric (e.g., metric tons of CO_2 per megawatt hour of generated electricity).
Storage Volume	A space within the subsurface into which the project CO_2 is injected and where the injected CO_2 is stored permanently.
Venting Emissions	Emissions through dedicated vent stacks during normal operation, process upsets, or shutdowns. These emissions can occur in the capture, transport, injection, and storage segments of the project and are calculated using procedures described in Section 4.0.

APPENDIX A: ENHANCED OIL RECOVERY OVERVIEW AND EMISSIONS

Crude oil development and production in U.S. oil reservoirs has included three distinct phases: primary, secondary, and tertiary (or enhanced) recovery. After primary and secondary techniques have been used to recover the easy-to-produce oil, producers have attempted several tertiary, or EOR, techniques.

Three major categories of EOR have been found to be commercially successful to varying degrees depending on the oil and reservoir properties and implementation costs:

- Thermal recovery, which involves the introduction of heat such as the injection of steam to lower the viscosity, or thin the heavy viscous oil, and improve its ability to flow through the reservoir. Thermal techniques account for over 40 percent of U.S. EOR production, primarily in California.
- Gas injection, which uses gases such as natural gas, nitrogen, or carbon dioxide that expand in a reservoir to push additional oil to a production wellbore, or that dissolve in the oil to lower its viscosity and improves its flow rate. A description of CO_2 injection for EOR is included in this section. Gas injection accounts for nearly 60 percent of EOR production in the United States.
- Chemical injection, which can involve the use of long-chained molecules called polymers to increase the effectiveness of waterfloods, or the use of detergent-like surfactants to help lower the surface tension that often prevents oil droplets from moving through a reservoir. Chemical techniques account for about one percent of U.S. EOR production.[59]

The injection of CO_2 into oil reservoirs for EOR has been performed by the oil industry for more than 40 years. CO_2 EOR is based on the concept of miscible or immiscible displacement of oil by CO_2. A typical CO_2 flood operation is shown in Figure 3. CO_2 is compressed to supercritical conditions and injected into injection wells that are strategically placed within the pattern of wells across the areal extent of the reservoir. The injected CO_2 enters the reservoir and moves through the pore spaces of the rock, encountering residual droplets of crude oil, becoming miscible with the oil, and forming a concentrated oil bank that is swept towards the producing wells. At the producing wells—and there may be three, four or more producers per injection well—oil mixed with water and gas is pumped to the surface, where it flows to a centralized collection facility. The produced fluid containing oil, water, gas, and CO_2 is separated at the

[59] Enhanced Oil Recovery | Department of Energy

surface. Any produced CO_2 is re-compressed and re-injected along with additional volumes of new CO_2. The separated produced water is treated and re-injected, often alternating with CO_2 injection, in a water-alternating-gas (WAG) process.[60]

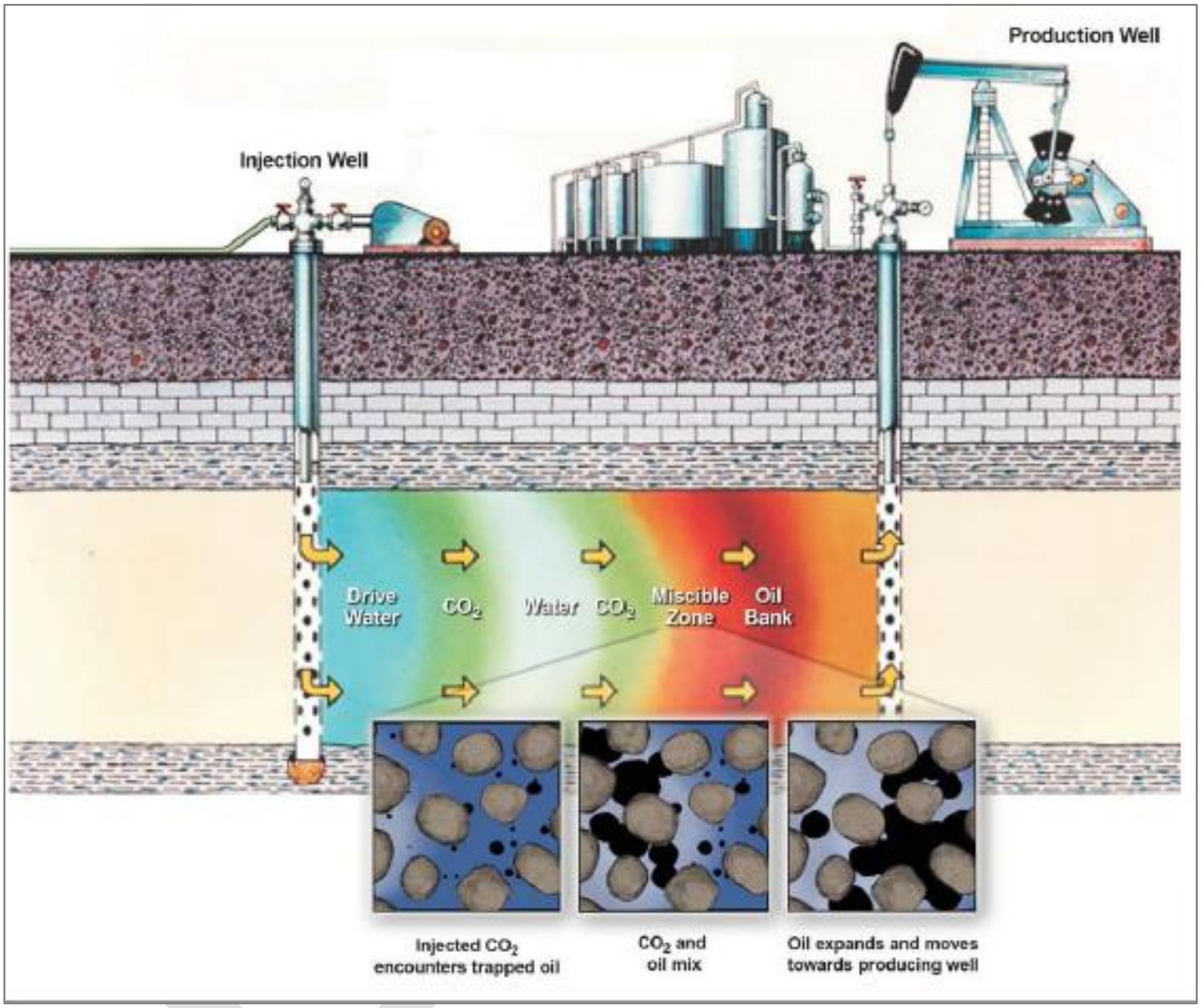


Figure 3: Typical EOR Process Using CO_2 and Water in a Water-alternating-gas (WAG) Process

An operator implementing an EOR project with CO_2 is highly motivated to track and contain all the CO_2 purchased as it is expensive. This CO_2 can be effectively measured and monitored while being handled in the surface facilities.

[60] Carbon Dioxide Enhanced Oil Recovery, US DOE, NETL, https://www.netl.doe.gov/sites/default/files/netl-file/CO2_EOR_Primer.pdf

When CO_2 is injected into the reservoir, it is generally injected at a pressure that results in total or partial miscibility with the oil in the reservoir. A portion of CO_2 will become soluble (mixed) with the oil and be recovered when the oil is produced. Of the remaining CO_2 injected, some of the CO_2 will be permanently trapped or mineralized in the rock's pore space, some will become dissolved in the formation brine, and the remainder will migrate within the reservoir. The CO_2 that is trapped in the rock's pore space is effectively sequestered forever. The CO_2 that is not trapped in the pore space and not mixed with the oil tends to migrate to the upper regions of the oil reservoir, as it is lighter than the oil and water in the formation. However, it remains contained in the oil reservoir because of the confining layer above the oil reservoir that traps it in place. This is the same confining layer that formed an effective seal and contained the oil and gas in the reservoir for millions of years and now serves to trap the CO_2.

Emissions from transportation, refining, and end-use of produced oil are considered project emissions and shall be accounted for five years after project start date of January 1, 2030, whichever is first. Example emissions are shown in Table 10, sources and emission factors follow.

Table 10: Case: Permian Basin Field API gravity 37.5 º ("Southwest" Region)

STEP	SUPPLY CHAIN STEP	CO_2E KG/BBL
A	Production GHG (will come from producer, not these tables)	21.00
B	Transport from field to refinery (default from Table 11 for Southwest)	2.38
C	Exports to foreign refineries (national default from **Error! Not a valid result for table.**)	2.20
D	Refining Emission (Table 13)	30.57
E	Transport from refinery to wholesale terminals (Table 14)	4.35
F	Transport of product exports (Table 15)	1.51
G	Product combustion/use (Table 17)	379.00
	Total	**441.01**

Note: Instructions for using tables are indicated by Steps A to G below. All heat contents in this and other tables are in units of higher heating value (HHV). Carbon dioxide equivalent (CO_2e) includes N_2O and CH_4. Diesel refers to low sulfur No. 2 fuel oil or diesel fuel.

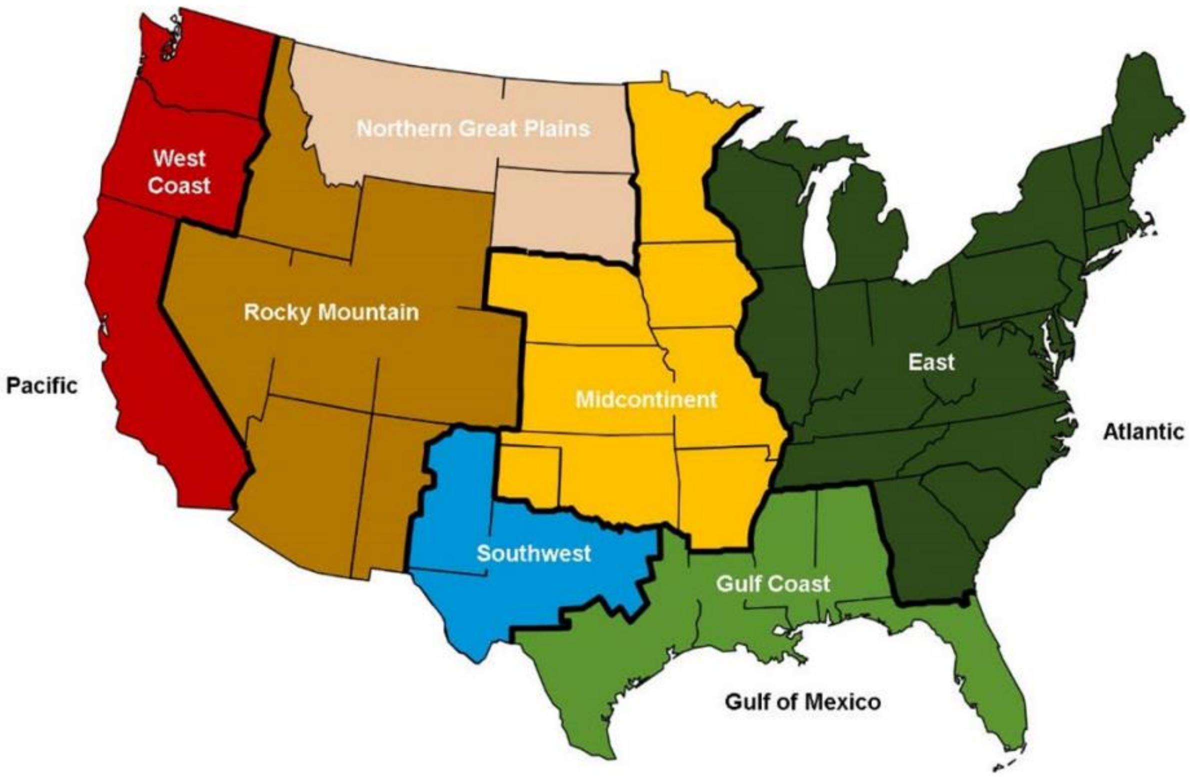


Figure 4: Map of the NEMS oil and gas supply regions.[61]

Use above map to identify NEMS region for region specific emissions in Table 11.

See Table 11 through Table 19 for calculating process emissions from produced oil.

Step A: Production emissions will come from producer.

Step B: Use Table 11, Column 1 to find the relevant NEMS region. Use the respective row in Column 22 for Field to Refinery transportation emissions for NEMS region.

[61] Map from "NEMS - National Energy Modeling System: An Overview." https://www.eia.gov/outlooks/archive/0581(2018).pdf

Table 11: Regional Weighted Averages for Crude Transportation from Field to Refinery (presumes domestic refining)[62]

	Average Characteristics					
1. Region	**2. API Gravity**	**3. Heat Content MMBtu/bbl**	**4. Density kg/cubic meter**	**5. bbl/metric ton**	**6. 2020 Production MMbpd**	**7. 2020 Production metric kton**
United States	**40.7**	**5.6**	**823.7**	**7.64**	**11.310**	**542,999**
Onshore East	50.9	5.3	779.0	8.07	0.158	7,138
Onshore Gulf Coast	36.7	5.7	844.1	7.45	1.431	70,090
Onshore Midcontinent	43.1	5.5	812.3	7.74	0.612	28,843
Onshore Southwest	42.8	5.5	813.1	7.74	4.490	211,861
Onshore Rocky Mountain	44.6	5.5	806.0	7.80	0.809	37,848
Onshore Northern Great Plains	43.7	5.5	808.4	7.78	1.204	56,479
Onshore West Coast	25.5	6.0	902.6	6.97	0.365	19,126
GOM State	32.6	5.8	863.1	7.29	0.020	989
GOM Fed Shallow	32.6	5.8	863.1	7.29	0.138	6,920
GOM Fed Deep	32.6	5.8	863.1	7.29	1.609	80,571
Pac Off State	38.0	5.7	837.6	7.51	0.020	972
Pac Off Federal	38.0	5.7	837.6	7.51	0.010	486
AK Onshore	37.7	5.7	841.1	7.48	0.355	17,340
AK State Offshore	37.7	5.7	841.1	7.48	0.089	4,335
AK Federal Offshore	37.7	5.7	841.1	7.48	0.000	0

[62] Ton-miles calibrated from the Freight Analysis Framework (FAF5 Regional Database): [Freight Analysis Framework | Bureau of Transportation Statistics (bts.gov)]

1. Region	8. Average Distance	9. Implied million metric ton-miles	10. Truck miles	11. Rail miles	12. Barge Water miles	13. Ocean Tanker Water miles	14. Pipeline miles	15. Truck metric ton-miles 10^6	16. Rail metric ton-miles 10^6	17. Barge Water metric ton-miles 10^6	18. Ocean Tankers Water metric ton-miles 10^6	19. Pipeline metric ton-miles 10^6	20. Weighted Avg Pipeline Factor g CO2e/metric ton-mile	21. Crude Transport Emissions 10^6 metric tons CO2e	22. Crude Transport within US CO2e kg/bbl
United States	**689**	**373,885**	**14**	**40**	**22**	**118**	**494**	**7,780**	**21,716**	**11,897**	**64,015**	**268,477**	**21.4**	**9,401**	**2.28**
Onshore East	341	2,435	18				323	129	-	-		2,306	22.3	73	1.26
Onshore Gulf Coast	309	21,648	18	5	20		266	1,264	350	1,380		18,654	21.1	699	1.34
Onshore Midcontinent	605	17,439	18				587	520	-	-		16,919	24.5	500	2.24
Onshore Southwest	682	144,481	18		20		644	3,821	-	4,171		136,489	22.2	3,896	2.38
Onshore Rocky Mountain	713	26,970	18	6			688	683	236	-		26,051	25.5	790	2.67
Onshore Northern Great Plains	859	48,541	18	374			467	1,019	21,130	-		26,392	24.7	2,008	4.57
Onshore West Coast	227	4,332	18				208	345	-	-		3,988	15.8	119	0.90
GOM State	61	60	-				61	-	-	-		60	20.5	1	0.17
GOM Fed Shallow	189	1,308	-				189	-	-	-		1,308	20.5	27	0.53
GOM Fed Deep	309	24,924	-		79		231	-	-	6,346		18,578	20.5	744	1.27
Pac Off State	229	223	-				229	-	-	-		223	16.2	4	0.49
Pac Off Federal	258	125	-				258	-	-	-		125	16.2	2	0.56
AK Onshore	3,753	65,084	-			2,953	800	-	-	-	51,212	13,872	23.4	718	5.54
AK State Offshore	3,763	16,314	-			2,953	810	-	-	-	12,803	3,511	23.4	181	5.57
AK Federal Offshore	3,773	0	-			2,953	820	-	-	-	0	0	23.4	0	5.60
Emission factor in grams/tonne-mile (pipeline is weighted 90% electric drive and 10% diesel drive)								*163.3*	*56.3*	*57.2*	*7.7*	*21.4*			

This is expected to be the primary table that would be used to estimate GHG emissions for crude transportation from field to refinery using “typical” or “default values”.

Step C: Use Table 12, Column 8, default value in red (2.2 CO_2e kg/bbl) for transportation emissions for exported crude oil.

Table 12: Transportation Emissions for Exported Crude Oil[63]

US Crude Oil Exports 2020 (million metric tons)				GHG Emissions			
1. Destination	2. 10^6 metric tons	3. Distance in Statute Miles	4. 10^6 metric ton-miles	5. Emission Factor Ocean Tanker grams/metric ton-mile	6. GHG Emission (CO2e 10^6 metric tons)	7. CO2e kg/metric ton	8. CO2e kg/bbl
Canada	21.3	1,658	35,361	7.7	0.27	12.8	1.68
Mexico	0.0	336	-	7.7	-		
US	0.0	0	-	7.7	-		
S. & Cent. America	8.5	3,469	29,635	7.7	0.23	26.8	3.51
Europe	57.9	6,873	398,185	7.7	3.08	53.1	6.96
Russia	0.0	8,632	0	7.7	0.00	66.7	8.74
Other CIS	0.1	9,459	774	7.7	0.01	73.1	9.57
Middle East	1.9	10,052	19,036	7.7	0.15	77.7	10.17
Africa	0.2	6,795	1,163	7.7	0.01	52.5	6.88
Australasia	3.3	10,448	34,569	7.7	0.27	80.7	10.57
China	19.8	9,890	195,392	7.7	1.51	76.4	10.01
India	10.7	11,617	124,193	7.7	0.96	89.8	11.76
Japan	2.0	8,627	17,087	7.7	0.13	66.7	8.73
Singapore	2.7	11,144	30,490	7.7	0.24	86.1	11.28
Other Asia Pacific	26.9	10,956	294,334	7.7	2.27	84.7	11.09
Total	**155.3**	**7,600**	**1,180,218**	**7.7**	**9.12**	**58.7**	**7.69**
Average percent of US production that was exported						29%	29%
"Adder" above domestic transportation GHGs to account for exported crudes and condensates						**16.80**	**2.20**

Note: CO2e kg/bbl calculated using weighted average 7.64 barrels per metric ton for US production.

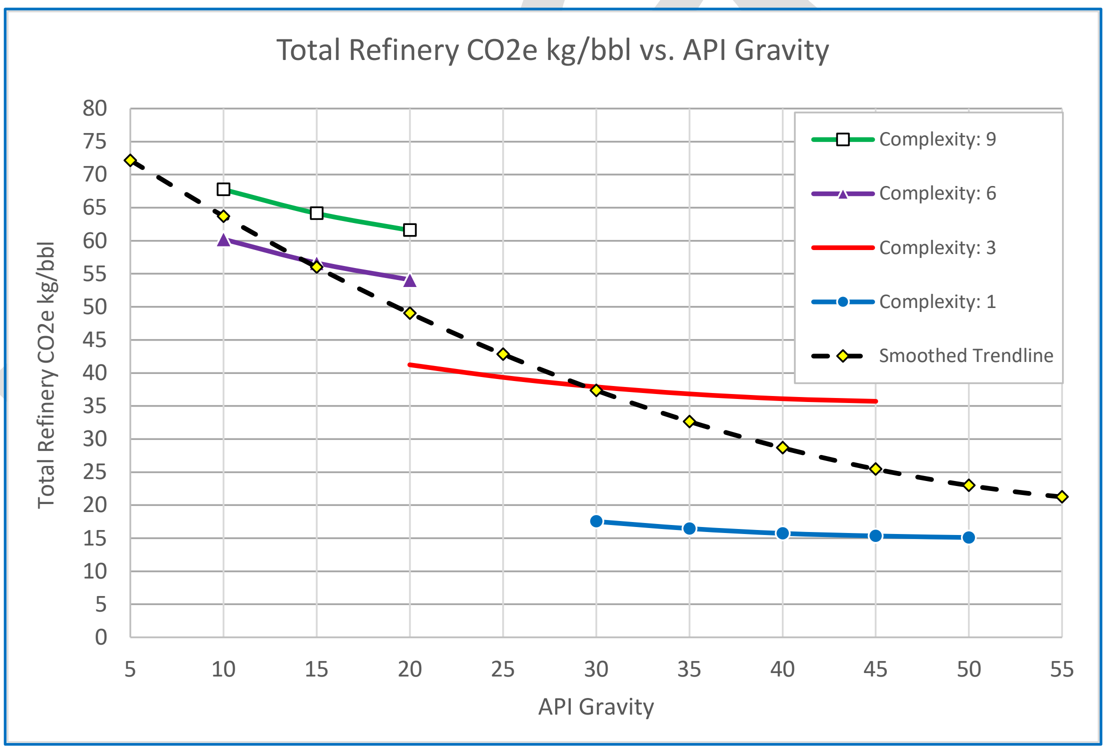
Approximately 29% of US crude are exported outside of the US. To account for this in a "default" manner, 2.2 CO_2e kg/bbl (e.g., 29% of 7.69 CO_2e kg/bbl) shall be added to the domestic transport GHG. If all the crude is expected to be transported outside of the US (project proponent shall provide supporting documentation) then 7.69 CO_2e kg/bbl would have to be added in the default method. If the country to which the crude is going is known, the value for that specific country could be used, multiplied by the percentage being exported. It is unlikely that that international destinations for crude will be known.

Step D: Use Table 13, Column 2 to identify the relevant API gravity. Use Column 3 in the corresponding row for emissions from refining.

[63] Distances calibrated from the BP Statistical Review of World Energy: Statistical Review of World Energy | Energy economics | Home (bp.com)

Table 13: GHG Emissions from Refining

1. Classification	2. Average API Gravity of Crude	3. Refinery CO2e kg/bbl (smoothed trendline)	4. Crude Inputs by Category as % of All US Crude Inputs
Extra Heavy	5.5	71.28	0.22%
Heavy	12.5	59.76	7.15%
Heavy	17.5	52.43	10.30%
Heavy	22.5	45.84	10.14%
Medium	27.5	40.00	15.41%
Medium	32.5	34.91	12.91%
Light	37.5	30.57	11.42%
Light	42.5	26.97	17.42%
Light	47.5	24.13	9.67%
Light	52.5	22.03	2.96%
Light	57.5	20.68	1.47%
Light	62.5	20.07	0.57%
Light	67.5	19.67	0.38%
US Weighted Average	**32.7**	**36.81**	**100.00%**



To account for GHG emissions at the petroleum refinery, use Table 13. Alternatively, the value can be read off the above chart.

Step E: Use Table 14, Column 18 (4.35 CO2e kg/bbl) for transportation emissions from refinery to wholesale terminals.

Table 14: Refined Petroleum Product Transportation from Refinery to Wholesale Terminals

1. Domestic Transportation of Petroleum Products from US Refineries	2. bbl/ metric ton	3. 2020 Production MMbpd	4. 2020 Production metric kton	5. Average Distance	6. Truck miles	7. Rail miles	8. Barge Water miles	9. Ocean Tanker Water miles	10. Pipeline miles	11. Truck metric ton-miles 10^6	12. Rail metric ton-miles 10^6	13. Barge Water metric ton-miles 10^6	14. Ocean Tankers Water metric ton-miles 10^6	15. Pipeline metric ton-miles 10^6	16. Total metric ton-miles 10^6	17. Domestic Transport Emissions 10^6 metric tons CO2e	18. Product Transport within US CO2e kg/bbl
United States	8.01	17.39	792,467	336	179	30	39	2	85	141,984	23,818	31,208	1,643	67,559	266,211	27,611	4.35
Emission factor in grams/metric ton-mile (pipeline is weighted 100% electric drive)										*163.3*	*56.3*	*57.2*	*7.7*	*19.0*			

Step F: Use Table 15, default value in red (1.51 CO_2e kg/bbl) for transportation emissions for exported refined petroleum products.

Table 15: Transportation Emissions for Exported Refined Petroleum Products[64]

US Petroleum Product Exports 2020 (million tonnes)				GHG Emissions			
1. Destination	2. 10^6 metric tons	3. Distance in Statute Miles	4. 10^6 metric ton-miles	5. Emission Factor Ocean Tanker grams/metric ton-miles	6. GHG Emission (CO2e 10^6 metric tons)	7. CO2e kg/metric ton	8. CO2e kg/bbl
Canada	24.4	1,658	40,506	7.7	0.31	12.8	1.64
Mexico	49.9	336	16,789	7.7	0.13	2.6	0.33
US	0.0	0	-	7.7	-		
S. & Cent. America	71.8	3,469	249,068	7.7	1.92	26.8	3.42
Europe	24.6	6,873	169,160	7.7	1.31	53.1	6.78
Russia	0.0	8,632	9	7.7	0.00	66.7	8.52
Other CIS	0.0	9,459	31	7.7	0.00	73.1	9.33
Middle East	2.1	10,052	20,833	7.7	0.16	77.7	9.92
Africa	6.2	6,795	42,191	7.7	0.33	52.5	6.70
Australasia	1.5	10,448	15,259	7.7	0.12	80.7	10.31
China	8.6	9,890	84,837	7.7	0.66	76.4	9.76
India	9.6	11,617	111,177	7.7	0.86	89.8	11.46
Japan	12.1	8,627	104,591	7.7	0.81	66.7	8.51
Singapore	3.7	11,144	41,602	7.7	0.32	86.1	10.99
Other Asia Pacific	25.6	10,956	280,906	7.7	2.17	84.7	10.81
Total	**240.2**	**4,901**	**1,176,959**	**7.7**	**9.10**	**37.9**	**4.83**
Average percent of US refinery output that was exported						31%	31%
"Adder" above domestic transportation GHGs to account for exported petroleum products						**11.86**	**1.51**

Note: CO2e kg/bbl calculated using weighted average 7.83 barrels per metric ton for US production.

[64] Distances calibrated from the BP Statistical Review of World Energy: [Statistical Review of World Energy | Energy economics | Home (bp.com)]

About 31% of US refinery outputs are exported as refined petroleum products. To account for this in a "default" manner, 1.51 CO_2e kg/bbl shall be added to the domestic product transport GHG found in Table 15.

Step G: Use Table 16, Column 2 to identify the relevant API gravity. Use column 3 in the corresponding row for emissions from combustion and use.

Table 16: Emissions from Combustion or Other Use of Petroleum Products Approximated by Crude Type

1. Classification	2. Average API Gravity of Crude	3. Combustion & Use CO2e kg/bbl (before blending, oxygenates)	4. Combustion & Use CO2e kg/bbl (after blending, oxygenates)	5. Crude Inputs by Category as % of All US Crude Inputs
Extra Heavy	5.5	437	412	0.22%
Heavy	12.5	420	397	7.15%
Heavy	17.5	408	387	10.30%
Heavy	22.5	399	379	10.14%
Medium	27.5	391	372	15.41%
Medium	32.5	384	367	12.91%
Light	37.5	379	362	11.42%
Light	42.5	369	354	17.42%
Light	47.5	354	341	9.67%
Light	52.5	347	334	2.96%
Light	57.5	332	322	1.47%
Light	62.5	318	310	0.57%
Light	67.5	303	297	0.38%
US Weighted Average	**32.7**	**385**	**367**	**100.00%**

Source: Estimates based on typical carbon content of crude oils and energy used in the refining process. The third column represents the CO2 in the refinery outputs before blending of oxygenates, biofuels, butanes, imported blendstocks, etc. The fourth column includes the effects of such blending agents.

Table 17: Emissions from Combustion or Other Use, Specified by Individual Petroleum Product

1. Petroleum Product	2. GREET Combustion GHG CO_2e (kg/bbl)	3. GREET Combustion GHG CO_2e (kg/MMBtu)	4. MMB/ Year Refinery Output	5. Combustion CO_2e 10^6 MT per Year
Propane	213	63.1	435	92.6
Motor Gasoline	356	70.5	3,516	1,251.9
Aviation Gasoline	351	69.5	4	1.5
Jet Fuel	411	72.5	562	231.0
Kerosene	428	75.5	4	1.6
Distillate Fuel Oil	428	74.2	1,830	783.9
Residual Fuel Oil	474	75.4	119	56.1
PetChem FS	159	29.2	109	17.3
Naphthas Solvents	358	68.3	12	4.4
Lubricants	226	37.3	61	13.8
Waxes	413	74.5	2	0.7
Asphalt & RO	-	-	118	-
Petroleum Coke	629	102.7	306	192.3
Still Gas	293	46.6	241	70.6
Other Products	354	61.0	32	11.3
Average weighted by US refinery output	**371**	**69.7**	**7,350**	**2,729**
Weighted by US refinery output minus still gas and pet. coke	**363**	**68.9**	**6,803**	**2,466**

Note: Average for years 2018 to 2020. The weighted average values represent the mix of US refinery output and not the mix of US domestic consumption. "Petchem FS" refers to petrochemical feedstocks. "RO" is road oil.

Table 17, column 2 could be used for **Step G** if the producer knows the mix of refined products that will be produced. This is highly unlikely; Table 16 is more likely to be used to estimate combustion/utilization GHG emissions.

Table 18 is a source for some of the other tables presented here. It may be used as a substitute for Table 11 if a producer knows the specific transportation modes and distances for crude oil or products.

Table 18: The Total GHG Emissions (gCO2e) for Moving 1 Metric Ton of Petroleum Products (MT) per mile (mi) for Various Transportation Modes in Grams per Metric Ton-mile

1. Mode	2. Energy Source	3. Energy Input (Btu per metric ton-mile)	4. LCA GHG Emission Factor for Fuel (kg/MWh)	5. LCA GHG Emission Factor for Fuel (kg/MMBtu)	6. Energy-related GHG Emissions (grams CO2e/ metric ton-mile)	7. Embodied GHG Emissions (grams CO2e/ metric ton -mile)	8. Total GHG Emissions (grams CO2e/ metric ton-mile)
Truck	diesel	1,771.3	-	91.6	162.2	1.10	163.3
Railway	diesel	601.9	-	91.6	55.1	1.20	56.3
Pipeline	diesel	300.0	-	91.6	27.5	6.95	34.4
Pipeline	natural gas	300.0	-	63.9	19.2	6.95	26.1
Pipeline	electricity (US average)	110.5	373.1	109.4	12.1	6.95	19.0
	electricity (Onshore East)	110.5	405.0	118.7	13.1	6.95	20.1
	electricity (Onshore Gulf Coast)	110.5	364.7	106.9	11.8	6.95	18.8
	electricity (Midcontinent)	110.5	475.5	139.4	15.4	6.95	22.4
	electricity (Southwest)	110.5	401.2	117.6	13.0	6.95	19.9
	electricity (Rocky Mountain)	110.5	508.5	149.0	16.5	6.95	23.4
	electricity (Northern Great Plains)	110.5	482.1	141.3	15.6	6.95	22.6
	electricity (West Coast)	110.5	193.0	56.6	6.3	6.95	13.2
	electricity (GOM State)	110.5	345.5	101.3	11.2	6.95	18.1
	electricity (GOM Fed Shallow)	110.5	345.5	101.3	11.2	6.95	18.1
	electricity (GOM Fed Deep)	110.5	345.5	101.3	11.2	6.95	18.1
	electricity (Pac Off State)	110.5	205.5	60.2	6.7	6.95	13.6
	electricity (Pac Off Federal)	110.5	205.5	60.2	6.7	6.95	13.6
	electricity (AK Onshore)	110.5	438.2	128.4	14.2	6.95	21.1
	electricity (AK State Offshore)	110.5	438.2	128.4	14.2	6.95	21.1
	electricity (AK Federal Offshore)	110.5	438.2	128.4	14.2	6.95	21.1
	electricity (Nonproducing)	110.5	284.4	83.3	9.2	6.95	16.2
Pipeline	electricity (oil-fired)	110.5	-	268.5	29.7	6.95	36.6
Pipeline	electricity (gas-fired)	110.5	-	187.2	20.7	6.95	27.6
Pipeline	electricity (coal-fired)	110.5	-	303.9	33.6	6.95	40.5
Barge	diesel	614.5	-	91.6	56.3	0.90	57.2
Ocean Tanker	diesel	80.0	-	91.6	7.3	0.40	7.7
Ocean Tanker	bunker fuel	80.0	-	93.6	7.5	0.40	7.9

Note: Pipeline electricity emissions are from eGRID 2020 and are calculated by NEMS regions. If the region isn't known, the US average should be used. Electricity LCA for US average is assumed to be 373kg/MWh. Heat rate for oil and coal are assumed to be 10,000 Btu/kWh. All Btu measurements represent higher heating values.

Sample calculations are as follows:

1. Find relevant transport mode and energy source in columns 1 and 2.
2. Read off grams CO2e per metric ton-mile from column 8.
3. Divide grams CO2e per metric ton-miles by the number of barrels of your crude that make up one metric ton. This will produce a value of grams per barrel miles.
4. Multiply results from step #3 by the number of miles transported to get grams CO2e per barrel.
5. Divide step #4 by 1,000 to get kilograms CO2e per barrels

Column 5 is computed for electric-drive pumps: Column 4 / (3.412 MMBtu/MWh) = Column 5.

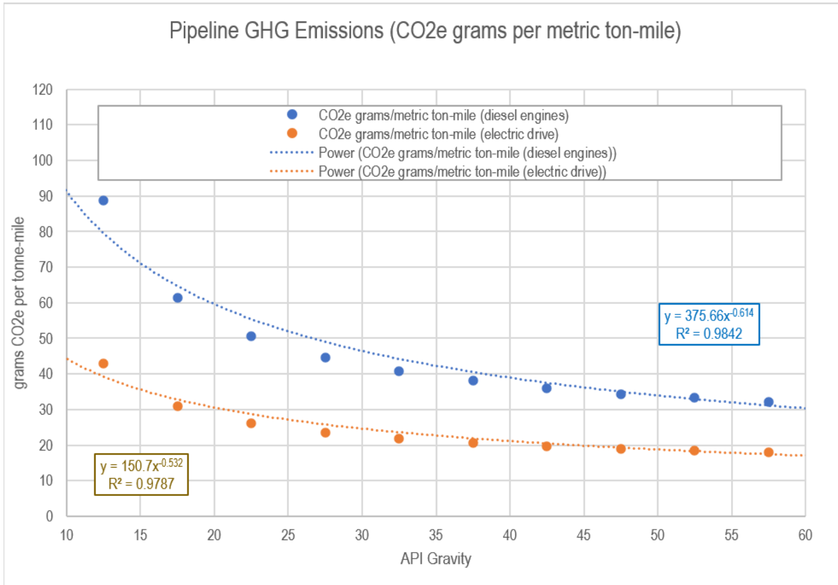
Column 3 x Column 5 / 1,000 = Column 6.

Table 19 and chart are provided as backup data for some of the other tables presented here that are used for **Step B or Step E**. You do not need to use this table or chart to do the required calculations.

Table 19: Crude Oils & Petroleum Products: GHG Emissions for Pipeline Transportation in CO2e Grams per Metric Ton-mile

1. Crude Classification	2. Average API Gravity	3. Pipeline Prime Mover Work (Btu/ metric ton-mile)	4. Fossil Prime Mover Energy Input (Btu/metric ton-mile)	5. Electric Prime Mover Energy Input (Btu/ metric ton-mile)	6. CO2e grams/metric ton-mile (diesel engines)	7. CO2e grams/metric ton-mile (electric drive)	8. bbl/ metric ton	9. Energy-related CO2e grams/bbl-mile (diesel engines)	10. Energy-related CO2e grams/bbl-mile (electric drive)
Extra Heavy	5.5	514	1,468	541	141.4	66.1	6.09	23.2	10.9
Heavy	12.5	312	892	329	88.6	42.9	6.40	13.8	6.7
Heavy	17.5	208	596	219	61.4	30.9	6.62	9.3	4.7
Heavy	22.5	167	478	176	50.7	26.2	6.85	7.4	3.8
Medium	27.5	144	413	152	44.7	23.6	7.07	6.3	3.3
Medium	32.5	130	370	136	40.8	21.9	7.29	5.6	3.0
Light	37.5	119	341	126	38.1	20.7	7.51	5.1	2.8
Light	42.5	111	317	117	36.0	19.7	7.73	4.7	2.6
Light	47.5	105	300	111	34.4	19.0	7.96	4.3	2.4
Light	52.5	101	287	106	33.2	18.5	8.18	4.1	2.3
Light	57.5	97	276	102	32.2	18.1	8.40	3.8	2.2
Light	62.5	97	276	102	32.2	18.1	8.62	3.7	2.1
Light	67.5	97	276	102	32.2	18.1	8.85	3.6	2.0
Products: gasoline		105	300	111	34.4	19.0	8.40	4.1	2.3
Products: diesel		105	300	111	34.4	19.0	7.44	4.6	2.6

Note: Electricity LCA emissions are assumed to be 373kg/MMWh. Values of CO2e include 6.95 grams per tonne-mile of embodied emissions related to pipeline construction.


Pipeline GHG Emissions (CO2e grams per metric ton-mile)
CO2e grams/metric ton-mile (diesel engines)
CO2e grams/metric ton-mile (electric drive)
Power (CO2e grams/metric ton-mile (diesel engines))
Power (CO2e grams/metric ton-mile (electric drive))
y = 375.66x-0.614
R² = 0.9842
y = 150.7x-0.532
R² = 0.9787
grams CO2e per tonne-mile
API Gravity
0
10
20
30
40
50
60
70
80
90
100
110
120
10
15
20
25
30
35
40
45
50
55
60

APPENDIX B: SUPPLEMENTAL QUANTIFICATION METHODS

This appendix provides information on supplemental quantification methods that may be applied to perform CO_2 mass balance calculations, to calculate GHG emissions from electricity usage, to calculate GHG emissions from stationary combustion from fuel use and in situations where a flare is used. Additional guidance on selecting emission factors for fugitive emissions at CO_2 injection, storage facilities and at hydrocarbon production facilities is also provided.

B.1 ADDITIONAL GUIDANCE ON PERFORMING CO_2 MASS BALANCES USING VOLUME OR MASS FLOW MEASUREMENTS

The mass balance equations presented in this methodology rely on continuous measurement of CO_2 at various stages of the CCS project. These flow measurements may be performed using either mass flow meters or volumetric flow meters. All of the calculations in the body of this document rely on volumetric measurements, but alternatively a mass-based measurement may be used. Both mass and volume-based measurement approaches are described in the following examples, below. Note that in these illustrative examples, measurements are assumed to be quarterly and other measurement frequencies may be required for CCS projects.

For a mass flow meter, the total mass of CO_2 must be calculated in metric tons by multiplying the metered mass flow by the concentration in the flow, according to the following equations.

Equation 35: Net annual mass of CO_2 (mass flow meter)

$$CO_{2_{T_x}} = \sum_{p=1}^{4} \left(Q_{x_p}\right) \times C_{CO_{2_{p_x}}}$$

WHERE

$CO_{2_{T_x}}$	Net annual mass of CO_2 measured by flow meter x (metric tons).
Q_{x_p}	Quarterly mass flow through meter x in quarter p (metric tons).

$C_{CO_{2px}}$	Quarterly CO_2 concentration measurement in flow for flow meter x in quarter p (wt. percent CO_2, expressed as a decimal fraction).
p	quarter of the year.
x	flow meter

For a volumetric flow meter, the total mass of CO_2 is calculated in metric tons by multiplying the metered volumetric flow at standard conditions by the CO_2 concentration in the flow, according to the formula below.

To apply the equation below, all measured volumes are converted to the following standard industry temperature and pressure conditions for use in the equation below: standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere.

Equation 36: Net annual mass of CO_2 (volumetric flow meter)

$$CO_{2_{T_x}} = \sum_{p=1}^{4} \left(Q_{x_p}\right) \times D \times C_{CO_{2_{px}}}$$

WHERE

$CO_{2_{T_x}}$	Net annual mass of CO_2 measured by flow meter x (metric tons).
Q_{x_p}	Quarterly volumetric flow through meter x in quarter p at standard conditions (standard cubic meters).
D	Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.
$C_{CO_{2px}}$	Quarterly CO_2 concentration measurement in flow for flow meter x in quarter p (vol. percent CO_2, expressed as a decimal fraction).
p	quarter of the year.
x	flow meter

When CO_2 is measured using more than one meter within the same component of the CCS project (e.g., multiple CO_2 injection wells), it may be necessary to sum the meter readings to calculate an aggregate mass of CO_2, as shown in the following equation.

Equation 37: Total mass of CO_2

$$CO_2 = \sum_{x=1}^{X} CO_{2_{T_x}}$$

WHERE

CO_2	Total mass of CO_2 measured by all flow meters in year y (metric tons).
$CO_{2_{T_x}}$	Total mass of CO_2 measured by flow meter x, as calculated in Equation 35 or Equation 36 in year y (metric tons).
X	Total number of flow meters.

B.2 ADDITIONAL METHOD FOR CALCULATING EMISSIONS FROM ELECTRICITY USE

The following equation can be used to quantify GHG emissions from the use of grid electricity at any component of a CCS project as a contingency if a distinct electricity meter reading is unavailable (e.g., other loads that are unrelated to the CCS project are tied into the same meter).

Equation 38: Project emissions from electricity used to operate equipment at the CO_2 storage site

$$PE_{S\text{-}P\text{-}Elec_y} = \sum (\text{Electrical Rating}_i \times \text{Hours}_i \times \text{Load}_i) \times EF_{Electricity}$$

WHERE

$PE_{S\text{-}P\text{-}Elec_y}$	Project emissions from electricity used to operate equipment at the CO_2 storage site in year **y** (tCO_{2e}/yr).
$\text{Electrical Rating}_i$	Electrical rating in MW for each piece of equipment used to operate equipment associated with the relevant component (e.g., capture, transport, or storage) of the CCS project (MW).
Hours_i	Operating hours for each piece of equipment (hours). Estimated or assumed to be 8760 hours for conservativeness.

$Load_i$	% Loading of each piece of equipment (unitless). Estimated or assumed to be 100%.
$EF_{Electricity}$	Emission factor for electricity generation in the relevant region, by (in order of preference) BAA, eGRID subregion, or State (tCO_2e/MWh). See Section 4.2.1 for estimation procedures.

B.3 ADDITIONAL METHOD FOR CALCULATING STATIONARY COMBUSTION EMISSIONS FROM THE PRIMARY PROCESS BASED ON FUEL USE

The following equation can be used to quantify GHG emissions from stationary combustion from the primary process at the capture site. It can be used for projects where directly measuring the volume (or mass) of CO_2 produced at the primary process is not possible.

Equation 39: Gross amount of CO_2 produced from the primary process

$$\mathbf{CO_2Produced_{PP_y}} = \sum \left(\mathbf{Fuel_i} \times \mathbf{Mass\ Frac_{Carbon_i}} \times \frac{\mathbf{44}}{\mathbf{12}} \right)$$

WHERE

$CO_2Produced_{PP_y}$	Gross amount of CO_2 produced from the primary process in each year (tCO_2/yr).
$Fuel_i$	Total volume or mass of fuel, by fuel type **i**, input into the primary process in year each (e.g., m^3 or kg).
$Mass\ Frac_{Carbon_i}$	Average mass fraction of carbon in fuel type **i**, (fraction, expressed as a decimal).
$\frac{44}{12}$	Conversion factor to convert from mass of carbon to mass of carbon dioxide using molecular weights (unitless).

B.4 ADDITIONAL METHOD FOR CALCULATING STATIONARY COMBUSTION EMISSIONS FROM FLARING

The following equation can be used to quantify GHG emissions from stationary combustion at the storage site in situations where a flare is used to combust gases produced from the formation (e.g., gases that may contain CO_2 that originate from the capture site).

Equation 40: Project emissions from flaring of gases at hydrocarbon production facilities

$$\begin{aligned} \mathbf{PE}_{\mathbf{Flaring}_y} = & \sum \left(\mathbf{Gas\ Flared_i} \times \sum (\mathbf{C_i} \times \mathbf{y_i}) \times \frac{44.01}{23.64} \right) + \sum \left(\mathbf{Flare\ Fuel_i} \times \mathbf{EF\ CO_2}_{\mathbf{Flare\ Fuel_i}} \right) \\ & + \sum (\mathbf{Gas\ Flared_i} \times (\mathbf{1} - \mathbf{DE}) \times \%\mathbf{CH_4} \times \boldsymbol{\rho}\mathbf{CH_4}) \times \mathbf{CH_4\text{-}GWP} \\ & + \sum \left(\mathbf{Flare\ Fuel_i} \times \%\mathbf{CH_4} \times \boldsymbol{\rho}\mathbf{CH_4} \times (\mathbf{1} - \mathbf{DE}) \right) \times \mathbf{CH_4\text{-}GWP} \\ & + \sum \left[\left(\mathbf{Vol.}_{\mathbf{Gas\ Flared}} \times \mathbf{EF\ N_2O}_{\mathbf{Gas\ Flared_i}} \right) + \left(\mathbf{Flare\ Fuel_i} \times \mathbf{EF\ N_2O}_{\mathbf{Flare\ Fuel_i}} \right) \right] \\ & \times \mathbf{N_2O\text{-}GWP} \end{aligned}$$

WHERE

$PE_{Flaring_y}$	Project emissions from flaring of gases at hydrocarbon production facilities in year y (tCO_{2e}/yr). Only applicable to facilities that flare gases that may contain CO_2 originating from the producing formation.
$Gas\ Flared_i$	Volume of gas flared at hydrocarbon production facilities at the storage site in year y (m^3/year).
$Flare\ Fuel_i$	Volume of each supplemental fuel, by fuel type i, used to ensure complete combustion of gases from the producing formation in year y (m^3/year).
C_i	Number of carbon atoms would be assessed based on the chemical formula of each gas (e.g., 1 for CH_4, 1 for CO_2, 2 for C_2H_6)
y_i	Direct measurement of the mole fractions of each carbon-containing gas in the gas mixture.
44.01	Reference value for Molecular Weight of CO_2 (grams per mole).

23.64	Volume occupied by 1 mole of an ideal gas at standard conditions of 15°C and 1 atmosphere.
DE	Destruction efficiency of the flare (unitless).
$\%CH_4$	Concentration of CH_4 in the gas stream that is being flared in year y (volume percent CO_2 or CH_4, expressed as a decimal fraction).
ρCH_4	Density of CO_2 at standard conditions = 0.00190 metric ton/m^3.
$EF\ N_2O_{Gas\ Flared_i}$	N_2O emission factor for flaring of gas stream originating from the producing formation (e.g., tN_2O/m^3).
$EF\ CO_{2_{Flare\ Fuel_i}}$	CO_2 emission factor for combustion of each supplemental fuel, by fuel type i, used to ensure complete combustion of gases from the producing formation (e.g., tCO_2/m^3).
$EF\ N_2O_{Flare\ Fuel_i}$	N_2O emission factor for combustion of each supplemental fuel, by fuel type i, used to ensure complete combustion of gases from the producing formation (e.g., tN_2O/m^3).
CH_4-GWP	Global Warming Potential of CH_4.
N_2O-GWP	Global Warming Potential of N_2O.

B.5 ADDITIONAL GUIDANCE ON SELECTING EMISSION FACTORS TO QUANTIFY FUGITIVE EMISSIONS

The following Table 20 provides a summary of potential fugitive and venting emission sources and relevant USEPA emission factors that may be applicable to CO_2 injection and storage facilities as well as to hydrocarbon production facilities at the storage site in the producing formation.

Table 20: Surface Components as Potential Emissions Sources at Injection Facilities[65]

EMISSIONS SOURCE	ENGINEERING ESTIMATES	DIRECT MEASUREMENT	EQUIPMENT COUNT AND POPULATION FACTOR	REFERENCE IN EPA GHGRP SUBPART W
Natural gas pneumatic high bleed device venting			X	EQ. W-1
Natural gas pneumatic high low device venting			X	EQ. W-1
Natural gas pneumatic intermittent bleed device venting			X	EQ. W-1
Natural gas driven pneumatic pump venting			X	EQ. W-1
Reciprocating compressor rod and packing venting			X	Eq. W-26 and W-27
EOR Injection Pump			X	
EOR injection pump blowdown	X			Eq. W-37
Centrifugal compressor wet seal oil degassing venting			X	Eq. W-22 to W-25
Other equipment leaks (valve, connector, open-ended line, pressure relief valve)			X	Eq. W-31

[65] US Environmental Protection Agency. Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems, Final Rule: Subpart W. November 30, 2010.

APPENDIX C: STANDARDS AND PROCEDURES FOR CLASS II WELLS IN TEXAS

The official rules of the Railroad Commission of Texas are found in the Texas Administrative Code (TAC) Title 16, Part 1, Chapters 1-20.[66] Chapter 3 includes rules of the Oil and Gas Division. Under Statewide Rules 9, 46, 95, 96, and 97, operators of injection and disposal wells associated with oil and gas exploration, production, transportation, or underground storage Class II wells must obtain a permit from the Railroad Commission. Thus, all Class II wells in Texas must be approved by the Commission before injection operations can legally begin. Pursuant to Rules 9, 46, 95, 96, and 97, and the applicable application forms, such permits will be approved only if the applicant satisfies the burden of showing that fresh water will be protected.

Once a permit is granted, the operator is bound by all applicable Commission rules and permit conditions by virtue of accepting the right to operate pursuant to the permit. It is necessary to examine permit conditions, as well as statewide rules, in order to determine what actions are necessary for compliance.

C.1 TYPES OF PERMITS

Permits to dispose of salt water or other oil and gas wastes by injection into porous formations that are not productive of oil, gas, or geothermal resources are issued under Statewide Rule 9. Form W-14 is used to apply for this type of permit.

Permits to inject water, steam, gas, oil and gas wastes, or other fluids into porous formations that are productive of oil, gas, or geothermal resources are issued under Statewide Rule 46. Forms H-1 and H-1A are used to apply for this type of permit.

Permits to conduct hydrocarbon storage operations are issued under Statewide Rules 95, 96, or 97. Form H-4 is used to apply for these types of permits.

[66] https://www.rrc.texas.gov/general-counsel/rules/current-rules/

C.2 COMMERCIAL DISPOSAL WELLS

A commercial disposal well is a well whose owner or operator receives compensation from others for the disposal of oilfield fluids or other oil and gas wastes that are wholly or partially trucked to the well and the primary business purpose of the well is to provide these services for compensation. Permits for commercial disposal wells contain special conditions for surface facilities associated with waste management.

C.2.1 Permitting Process

All permit applications for Class II wells come to the Technical Permitting Section, where they are evaluated and processed. If a hearing is requested or required, the Technical Permitting Section requests that a hearing be scheduled, and the Commission provides notice to all interested persons. After the hearing, the examiners recommend final action to the Commissioners, who decide if the permit will be issued. If no protests are received on an application, the Director of Technical Permitting may administratively approve the application.

See the section titled "Injection and Disposal Well Permitting" for more detail on permitting standards and procedures.

C.2.2 Transfer and Modification of Permit

An injection or disposal well permit may be transferred only after notice to the Commission. Written notice of intent to transfer the permit must be submitted to the Commission on Form P-4 at least 15 days prior to the date the operators plan for the transfer to occur. Permit transfer will not occur until the Form P-4 has been approved by the Commission.

An injection or disposal well permit may be terminated, suspended, or modified for just cause, such as a substantial change in well completion or operation, pollution of fresh water, substantial violations of permit conditions or rules, misrepresentations by the applicant, or the escape of injected fluids from the authorized zone. Notice and opportunity for hearing are provided in the same manner as in the initial permit process.

C.2.3 Geological Requirements

The authorized injection or disposal strata must be isolated from overlying usable quality water by a sufficient thickness of relatively impermeable strata, which is generally considered to be an accumulative total of at least 250 feet of clay or shale. Variances in the total thickness required are considered on the basis of continuity of strata, thickness of individual strata, or the presence of relatively impermeable strata other than clay or shale. No injection or disposal well will be permitted where faults, fractures, structure, or other geologic factors indicate that isolation of the authorized injection or disposal zone is jeopardized. The operator must submit adequate geological information to show compliance with this requirement.

C.2.4 Casing and Cementing

Injection and disposal wells must be cased and cemented in accordance with Statewide Rule 13 to prevent the movement of fluids into sources of fresh water. Rule 13 requires that surface casing be set and cemented to protect freshwater strata, as defined by the Texas Commission on Environmental Quality (TCEQ), formerly the Texas Natural Resource Conservation Commission. Cement is required to be circulated to the surface by the pump and plug method, and the specifications for cement quality and casing integrity set out in the rule must be met.

Injection and disposal wells must also meet UIC criteria for adequacy of cement to confine injected fluids. These criteria are 100 feet of well bonded cement as determined by a bond log, 250 feet of cement as evidenced by a temperature survey, or 400 to 600 feet of cement as determined by a slurry yield calculation. The flexibility in calculated annular footage allows for consideration of the operating conditions, type of cement used, and characteristics of the formation.

Wells that are converted from producers to injection into the same productive formation usually meet UIC cementing requirements if they were completed in compliance with Rule 13.

C.2.5 Area of Review

Statewide rules require that an applicant for an injection or disposal well permit examine the data of record for wells that penetrate the proposed injection zone within a one quarter (1/4) mile radius of the proposed well to determine if all abandoned wells have been plugged in a manner that will prevent the movement of fluids into strata other than the authorized injection or disposal zone. A permit applicant must submit a map showing the location of all wells of public record within 1/4 mile as part of the permit application. For those wells that penetrate the top of the injection or disposal zone, the applicant must attach a tabulation of the wells showing the dates the wells were drilled and the present status of the wells. Alternatively, if the applicant can show, by computation, that a lesser area will be affected by pressure increases, then the lesser area may be used in lieu of the fixed radius. In addition, an applicant may seek a variance from the Area of Review requirements by demonstrating that no significant increase in risk of groundwater contamination will result from the variance. No permit will be issued where the information submitted indicates that freshwater resources will be endangered unless permit conditions require appropriate corrective action in the area (e.g., remedial cementing, re-plugging inadequately plugged area wells, or more frequent testing and monitoring).

C.2.6 Standard Equipment Requirements

All newly drilled or converted injection wells permitted under Rule 46 and all disposal wells permitted under Rule 9 must be equipped with tubing set on a mechanical packer unless an exception is granted by the director for good cause. Pressure observation valves are required on the tubing and each annulus.

C.2.7 Operating Requirements

Maximum injection pressure limitations have been part of the Commission's permitting program for many years and continue to be required as a condition of each injection or disposal well permit. Pressure limitations are established to provide adequate assurance that injection will not initiate fractures in the confining zones. The maximum surface injection pressure may not ordinarily exceed 1/2 psi per foot of depth to the top of the authorized injection or disposal interval. A fracture pressure step-rate test must be performed to justify a higher pressure.

C.2.8 Monitoring and Reporting

The operator of each injection or disposal well is required by the statewide rules to monitor the injection pressure and volume on a monthly basis and to report the results annually on Form H-10. Any downhole problem that indicates the presence of leaks in the well must be reported to the appropriate district office within twenty-four (24) hours.

See the section titled "Injection and Disposal Well Monitoring" for more detail on monitoring requirements.

C.2.9 Mechanical Integrity

All injection and disposal wells must be pressure tested before injection operations begin, after any workover that disturbs the seal between the tubing, packer, and casing, and at least once every five (5) years to determine if leaks exist in the tubing, packer, or casing. Some permits require more frequent tests, such as annual pressure tests for converted wells with short surface casing. The appropriate district office must be notified before any pressure test to allow a Commission representative to witness the test. The operator must then file a record of the test with the district office (Form H-5) within 30 days of the test. As an alternative to the five-year pressure testing, the operator may monitor the casing-tubing annulus pressure and report the results annually if the reported information demonstrates mechanical integrity and provided that the well is pressure tested at least once every ten (10) years.

Wells not equipped with tubing and packer or with other non-standard completions may require special down hole surveys to demonstrate mechanical integrity. These surveys must be approved in advance for a specific wellbore by Technical Permitting in Austin unless they are expressly required by the injection/disposal well permit.

See the section titled "Injection and Disposal Well Mechanical Integrity Testing" for more detail on mechanical integrity testing requirements.

C.2.10 Completion Reports

A completion report (Form W-2 or G-1) must be filed with the appropriate district office within thirty (30) days of completion or conversion to disposal or injection to reflect the new or current completion.

C.2.11 Exceptions

The statewide rules allow the director to grant exceptions to tubing and packer, packer setting depth, and pressure observation valve requirements of the rules upon proof of good cause. In addition, the district office may grant an exception to the surface casing requirements of Statewide Rule 13 and authorize use of the multistage completion process. Multistage cementing (in lieu of setting surface casing) is not normally authorized as a means to protect freshwater strata for wells drilled expressly as injection or disposal wells.

C.2.12 Plugging and Abandonment

All injection and disposal wells are required to be plugged upon abandonment, in accordance with Statewide Rule 14. A notice of intention to plug and abandon (Form W-3A) must be filed with the appropriate district office and received five (5) days prior to the beginning of plugging operations. Plugging operations may not begin prior to the date shown on the Form W-3A unless authorized by the District Director.

The general requirements of Rule 14 ensure the protection of all formations bearing fresh groundwater, oil, gas, or geothermal resources. Each well is also subject to the specific requirements of Rule 14 that are applicable to the particular well completion situation. Special plugging requirements that are specific to the well, field, or area may apply at the discretion of the District Director.

Within thirty (30) days after a well is plugged, a complete record (Form W-3) must be filed in duplicate with the appropriate district office.