



**Greenhouse Gas Emissions Reduction
Measurement and Monitoring Methodology
for Carbon Capture and Storage Projects
in Oil and Gas Reservoirs**

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TABLE OF CONTENTS

1.0	BACKGROUND AND APPLICABILITY	1
1.1	Background on CCS Projects.....	1
1.2	Applicability	2
1.3	Periodic Reviews and Revisions	3
2.0	PROJECT BOUNDARIES	4
2.1	Physical Boundary	4
2.2	Temporal boundary	7
2.3	Greenhouse Gas Assessment Boundary.....	7
3.0	BASELINE DETERMINATION	9
3.1	Baseline Description	9
3.1.1	Baseline Options for CCS Projects	9
3.1.2	Baseline Considerations for Retrofit and New-Build CCS Projects	10
3.2	Additionality Assessment	12
4.0	QUANTIFICATION METHODOLOGY.....	17
4.1	Baseline Emissions	17
4.1.1	Calculation Procedure for Projection-Based Baseline	18
4.1.2	Calculation Procedure for Standards-based Baseline.....	19
4.2	Project Emissions.....	20
4.2.1	Calculation Procedures for CO ₂ Capture	21
4.2.2	Calculation Procedures for CO ₂ Transport	31
4.2.3	Calculating CO ₂ Transport Emissions According to System-Wide Emission Factors.	36
4.2.4	Calculation Procedures for CO ₂ Storage.....	37
4.2.5	Accounting for CO ₂ Leakage from Geologic Storage Formations to the Atmosphere.....	47
4.3	Emission Reductions.....	49
5.0	DATA COLLECTION AND MONITORING	51
5.1	Verification Period.....	51
5.2	Baseline Emissions Measurement.....	51
5.3	Project Emissions Measurements.....	53
5.4	Monitoring, Reporting, and Verification (MRV) Plan.....	60
5.4.1	Site Characterization.....	62
5.4.2	Baseline Monitoring.....	64
5.4.3	Operational Monitoring.....	64

5.4.4	Post-injection Monitoring	65
5.5	Measurement Techniques	67
5.6	Data and Analysis for Verification	68
6.0	EMISSIONS OWNERSHIP AND QUALITY.....	79
6.1	Statement of Direct Emissions.....	79
6.2	Title.....	79
6.3	Permanence and Liability.....	79
6.4	Pore space ownership.....	81
6.5	Community and Environmental Impacts	83
7.0	QA/QC.....	84
8.0	UNCERTAINTIES	86
A.0	APPENDIX A- SUPPLEMENTAL QUANTIFICATION METHODS	90
B.0	APPENDIX B: STATE LEGISLATIVE ACTIONS.....	96

LIST OF FIGURES

Figure 1-1	Basic CCS Project Schematic	2
Figure 2-1	CCS Project Boundary	6
Figure 3-1	Major US CO ₂ Pipelines.....	15
Figure 5-1	Points of CO ₂ Measurement for the CCS Project	58

LIST OF TABLES

Table 2-1	Greenhouse Gases Considered in the Assessment Boundary	8
Table 3-1	Industrial Plants in the US with CCS	14
Table 3-2	US Natural and Anthropogenic Sources of CO ₂ for EOR.....	16
Table 5-1	Overview of Baseline Emissions Calculation Procedures	52
Table 5-2	Overview of Project Emissions Calculation Procedures.....	54
Table 5-3	Points of CO ₂ Measurement for the CCS Project (Associated with Figure 5-1)	59
Table 5-4	Monitoring for CO ₂ --EOR Sequestration.....	66
Table 5-5	Monitoring Parameters.....	69
Table 8-1	Potential Sources of Uncertainty.....	87
Table A-1	Surface Components as Potential Emissions Sources at Injection Facilities	95

1.0 BACKGROUND AND APPLICABILITY

1.1 Background on CCS Projects

Carbon capture and storage (CCS) is the separation and capture of carbon dioxide (CO₂) from the atmospheric emissions of industrial processes or the direct air capture (DAC) of atmospheric CO₂ and the transport and safe, permanent storage of the CO₂ in deep underground geologic formations.^{1 2}

In CCS, CO₂ that would otherwise have been emitted into the atmosphere or that currently resides in the atmosphere is captured and disposed of underground. By preventing CO₂ from large-scale industrial facilities from entering the atmosphere or by removing the CO₂ that currently resides in the atmosphere, CCS is a powerful tool for addressing potential climate change. Geologic storage is defined as the placement of CO₂ into a subsurface formation so that it will remain safely and permanently stored. Examples of subsurface formations include deep saline aquifers and oil and gas producing reservoirs.

The CO₂ for geologic storage comes either from industrial facilities that emit large amounts of CO₂, particularly those that burn coal, oil, or natural gas; or potentially directly from the atmosphere itself via large-scale chemical DAC facilities. Industrial facilities include power plants, petroleum refineries, oil and gas production facilities, iron and steel mills, cement plants, and various chemical plants.

This methodology outlines the requirements and process for CCS project proponents to qualify their projects for carbon credits under the American Carbon Registry® (ACR) program. The methodology is based on the accounting framework developed by the Center for Climate and Energy Solutions (formerly the Pew Center on Global Climate Change)³

¹ What is carbon sequestration (or carbon capture and storage)?, http://www.netl.doe.gov/technologies/carbon_seq/FAQs/carbonseq.html

² The Business of Cooling the Planet, Fortune, October 7, 2011, <http://tech.fortune.cnn.com/2011/10/07/the-business-of-cooling-the-planet/>

³ A Greenhouse Gas Accounting Framework for Carbon Capture and Storage Projects, Center for Climate and Energy Solutions, February, 2012

1.2 Applicability

The methodology is applicable to projects that capture, pipeline transport and inject anthropogenic CO₂ into an underground CO₂ reservoir where it is sequestered. Figure 1-1 provides a basic schematic of a CCS project illustrating the scope of the methodology.

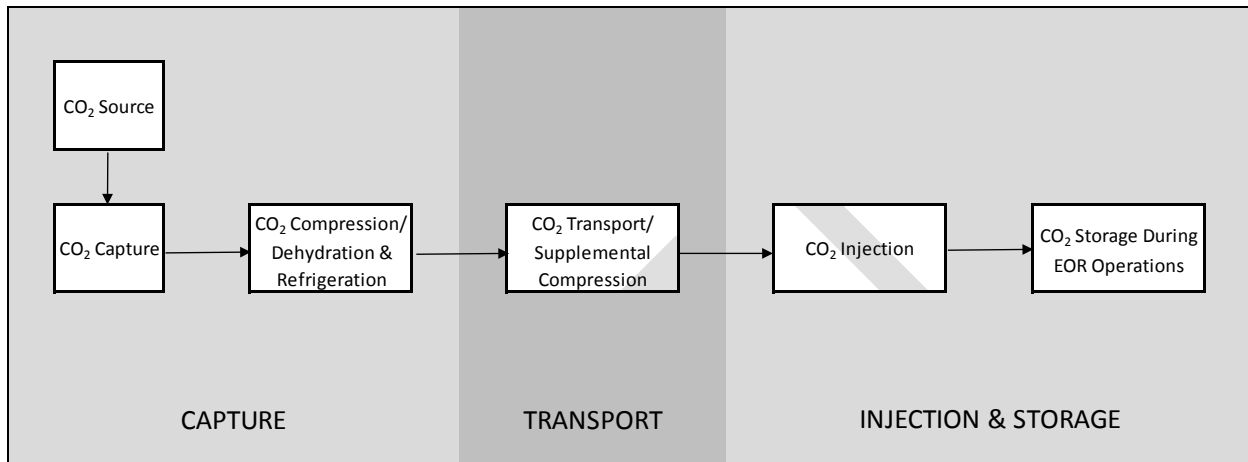


Figure 1-1 Basic CCS Project Schematic

With respect to the capture of CO₂, the methodology applies to multiple CO₂ source types, including electric power plants – equipped with pre-combustion, post-combustion, or oxy-fired technologies, industrial facilities (for example, natural gas production, fertilizer manufacturing, and ethanol production), polygeneration facilities (facilities producing electricity and one or more of other commercial grade by products), and DAC facilities. For transporting CO₂, there are essentially two options: trucking it from the source to the storage field or moving the CO₂ in a pipeline. The methodology applies only to pipelines because while other methods of transport, (e.g., truck transport) are possible, they are typically not considered economically viable for large-scale CCS endeavors. In considering the geological storage of CO₂, the methodology applies to enhanced oil and gas recovery projects. This includes projects where CO₂ is injected:

- to enhance production from hydrocarbon producing reservoirs that have previously produced or are currently producing through the use of primary and secondary recovery processes; or

- to produce from reservoirs that have not produced hydrocarbons through the use of primary or secondary recovery processes but have a potential for hydrocarbon recovery through CO₂ injection in the reservoir.

1.3 Periodic Reviews and Revisions

The ACR may require revisions to this methodology to ensure that monitoring, reporting, and verification systems adequately reflect changes in the project's activities. An annual attestation and a verification statement, which will include documentation of the findings of a third party verifier shall be submitted by the project entity to ACR. The ACR will then:

- review the attestation and verification statement and notify the project entity of any required adjustments or corrections to these documents, and
- register verified emission reductions.

This methodology may also be periodically updated to reflect regulatory changes, emission factor revisions, or expanded applicability criteria. Before beginning a project, the project proponent should ensure that they are using the latest version of the methodology.

2.0 PROJECT BOUNDARIES

Consistent with *ACR Standard* requirements, the project boundary includes a physical boundary, a temporal boundary, and a greenhouse gas (GHG) assessment boundary.

2.1 Physical Boundary

The physical boundary demarcates the sources included in the project and baseline emissions calculation (as presented in Section 4). Recognizing the variety and complexity of project configurations where CO₂ may be captured and compressed, transported and injected into different types of reservoirs, Figure 2-1 provides a general illustration of project boundaries to account for the full range of potential CCS project types.

Leakage. An important consideration when determining the project boundary is “leakage,” which refers to unintended increases in emissions due to the project activity – usually occurring outside the physical project boundary. An objective in defining boundaries is to minimize or avoid leakage.

In this methodology, the project boundary is intentionally drawn broadly to avoid unaccounted emissions associated with capturing and storing CO₂. Specifically it covers the full CCS value chain, including emissions from CO₂ recovery and re-injection operations at enhanced oil and gas recovery sites.

Primary Process. The installation of CO₂ capture may impact one or more emissions sources at a facility, but may also leave unaffected other sources. Therefore, to ensure the emissions reduction calculation approach reflects the relevant change in emissions due to the project, the baseline and project boundaries shall focus on incorporating GHG sources affected by the project – i.e., the change in emissions due to capturing CO₂. For example, a boundary for CO₂ capture at a hydrogen production unit within a refinery unit 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 upstream systems unaffected by the CO₂ capture system.

The specific power generation or industrial process (e.g., natural gas processing, hydrogen production, steelmaking) creating the captured CO₂ is referred to in this document as the “primary process.” If CO₂ is captured from more than one process, then project developers shall combine them within the boundary that encompasses the capture site.

DRAFT

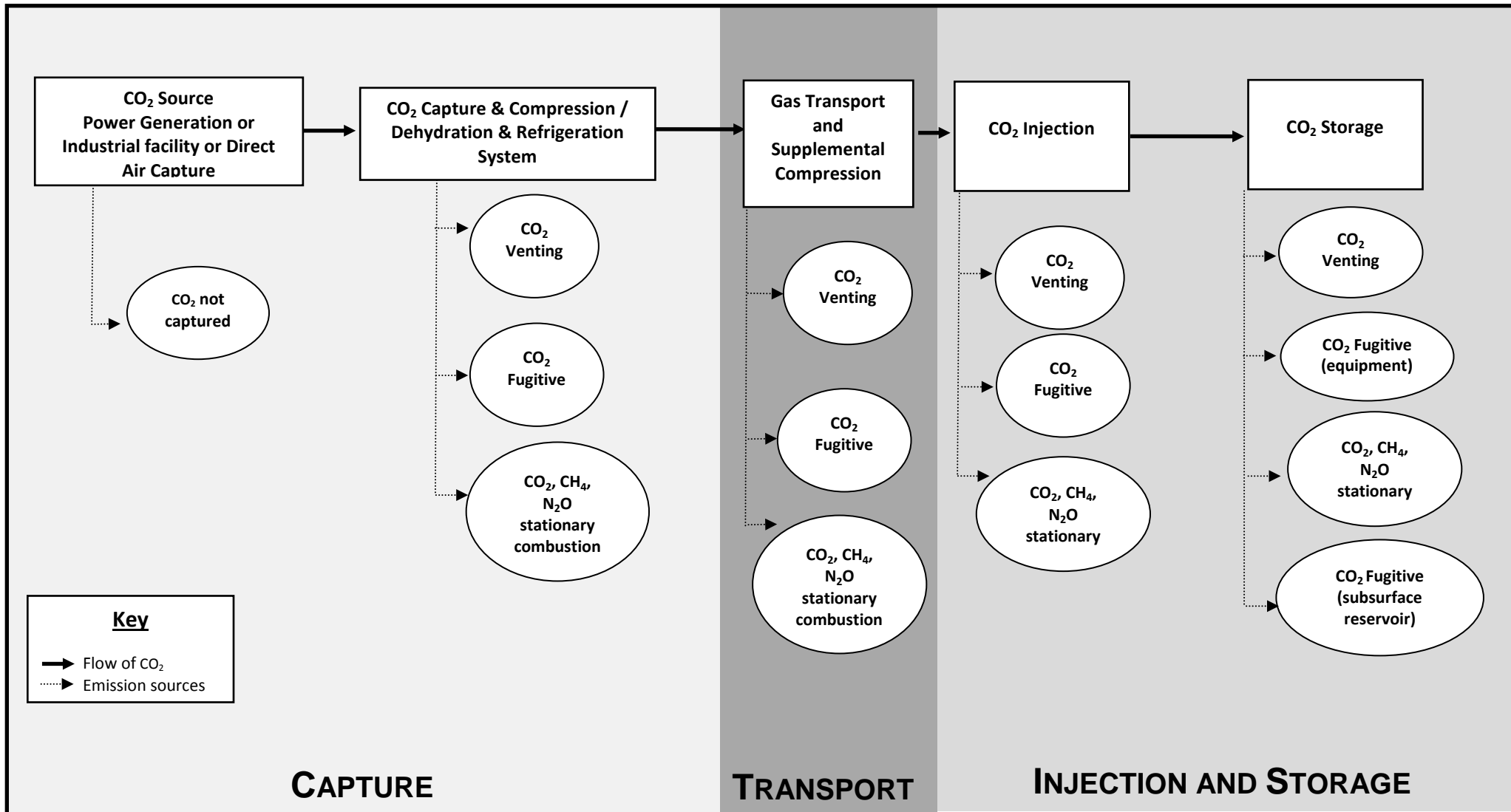


Figure 2-1 CCS Project Boundary

2.2 Temporal boundary

For qualifying CCS projects, the project start date is January 1, 2000 or the date when the project's captured CO₂ is first injected and sequestered in the subsurface, whichever is later. For CCS projects associated with ongoing EOR operations, the sequestration site may already be utilizing CO₂ from other sources delivered through an existing CO₂ pipeline network (e.g., West Texas). In those situations, the project start date is the date when custody of the project's captured CO₂ is first transferred to the EOR operator.

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 adoption rates are extremely small (section 3.2), the crediting period for these projects shall be 10 years. At the end of each ten-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. ACR does not limit the allowed number of renewals.

The minimum 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 CO₂ injection plus a time-period following the end of injection during which the reservoir is monitored for leakage to the atmosphere. The minimum post-injection period for CCS projects is five (5) years. As discussed in Section 6.3, the duration of post-injection monitoring could be extended beyond 5 years based on the monitoring results obtained during this 5-year period and its conformance to model predictions. If permanence cannot be assured based on the monitoring during this period, the project term will be extended in two-year increments until permanence is assured.

2.3 Greenhouse Gas Assessment Boundary

The greenhouse gases included in calculations of baseline emissions and project emissions are shown in Table 2-1.

Table 2-1 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	Exclusion is conservative	
		N ₂ O	No	Exclusion is conservative	
CO₂ Capture					
Project	Non-captured CO ₂ from the primary process (vented and fugitive)	CO ₂	Yes	CO ₂ is major emission from source	
		CH ₄	No	Exclusion is consistent with baseline	
		N ₂ O	No	Exclusion is consistent with baseline	
	Stationary combustion	CO ₂	Yes	CO ₂ is major emission from source	
		CH ₄	Yes	Included for completeness	
		N ₂ O	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 ₂ O	Yes	Included for completeness	
	CO₂ Transport				
	Stationary combustion	CO ₂	Yes	CO ₂ is major emission from source	
		CH ₄	Yes	Included for completeness	
		N ₂ O	Yes	Included for completeness	
	Vented & fugitive emissions	CO ₂	Yes	CO ₂ is major emission from source	
		CH ₄	No	Exclusion is consistent with baseline	
		N ₂ O	No	Exclusion is consistent with baseline	
	Electricity usage	CO ₂	Yes	CO ₂ is major emission from source	
		CH ₄	Yes	Included for completeness	
		N ₂ O	Yes	Included for completeness	
	CO₂ Storage				
	Stationary combustion	CO ₂	Yes	CO ₂ is major emission from source	
CH ₄		Yes	Included for completeness		
N ₂ O		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 ₂ O	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 ₂ O	Yes	Included for completeness		
Produced gas transferred outside project boundary	CO ₂	Yes	CO ₂ is major emission from source		
	CH ₄	No	Exclusion is consistent with baseline		
	N ₂ O	No	Exclusion is consistent with baseline		
Fugitive CO ₂ emissions from the geologic reservoir to the atmosphere	CO ₂	Yes	CO ₂ is major emission from source		
	CH ₄	No	Exclusion is consistent with baseline		
	N ₂ O	No	Exclusion is consistent with baseline		

3.0 BASELINE DETERMINATION

3.1 Baseline Description

In terms of GHG project accounting, a baseline is a hypothetical situation that represents the condition most likely to occur in the absence of the GHG emission reduction project. It serves as a reference case against which to quantitatively compare the GHG emissions associated with the project and derive net emission reductions.

The methodology presents two baseline options, referred to as “Projection-based” and “Standards-based.”

3.1.1 Baseline Options for CCS Projects

A project developer would select the baseline that applies to its project, and then follow the matching calculation procedure. The choice of baseline dictates the equations applied, as provided in Section 4.1.1 and 4.1.2:

Projection-based baseline	Baseline Equation 4.1
Standards-based baseline	Baseline Equation 4.2

Projection-based. This option represents a baseline that would correspond with the project’s actual CO₂ capture site, absent the capture and compression system located at the CO₂ source. For example, if the CCS project includes a coal electricity generator with post-combustion capture, a Projection-based baseline would be the coal plant without CO₂ capture; similarly, if the CCS project captures CO₂ from acid-gas removal associated with natural gas production, a Projection-based baseline would be the natural gas production facility with acid gas removal but with CO₂ vented to the atmosphere.

For most CCS projects, the Projection-based baseline scenario will apply. According to the calculation approach, project developers determine Projection-based baseline emissions according to actual measured quantities of CO₂ captured from the project, which would have been vented to the atmosphere had the CCS project not been implemented, minus the incremental CO₂ generated at the capture site due to CO₂ capture equipment. The calculation uses data collected in the project condition to represent the quantity of emissions prevented from entering the atmosphere.

Standards-based. The Standards-based baseline is expressed in the form of an intensity metric or “performance standard” (tCO₂e/unit of output). Depending on the circumstance, it could correspond with a similar or different technology than the CCS project’s actual CO₂ capture site, but which fulfills the same purpose and function. For instance, if the CCS project includes a coal 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 tons CO₂/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 CO₂ capture site.

If both baseline options are feasible for a given project, the more conservative option (i.e. the option likely to result in a lower estimate of baseline emissions and therefore a lower estimate of net emission reductions) shall be selected unless justification can be presented, acceptable to ACR and the validator, why the less conservative option represents a more credible and likely baseline scenario.

3.1.2 Baseline Considerations for Retrofit and New-Build CCS Projects

Depending on the situation, either the Projection-based or Standards-based baseline could apply to projects that capture CO₂ at power generation or other industrial facilities, and inject CO₂ at various types of storage sites.

Retrofit CCS Projects: Given the limited number of climate change policies 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 CO₂ source facility, but without carbon capture and storage – such that produced CO₂ is vented to the atmosphere. This corresponds with the Projection-based baseline.

However, if the retrofit involves a major overhaul of technologies, then applying a Projection-based baseline might not be the most reasonable approach. Instead, it may be more appropriate

to characterize the baseline in terms of the emissions rate associated with a specific technology, often called a performance standard.

A Standards-based baseline could also apply to retrofit projects if a law or regulation affects CO₂ emissions production at the capture site, such as a mandate to meet a minimum GHG emission performance standard.

New Build CCS Projects: The baseline for new facilities will often correspond with the common practice in the region and the most economic option available to the project developer. As with retrofit projects, provided that there are 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, the baseline for a new build facility would likely be the operation of the project configuration without the CCS capture component that vents all of the produced CO₂ to the atmosphere – a Projection-based baseline.

However, multiple economic and market, social, environmental, and political considerations exist that impact technology choices and configurations. Thus, project developers could decide that an emissions performance standard best represents its project circumstances and adopt a Standards-based baseline.

Current regulations shall be considered in determining whether to use a projection-based or standard-based baseline for new and existing sources. For example, for new sources, if a GHG NSPS requires new sources to meet an emissions performance benchmark, the standards-based baseline is appropriate and baseline emissions rate shall be set to the NSPS. 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 NSPS.

3.2 Additionality Assessment

Emission reductions from the project must be additional, or deemed not to occur in the business-as-usual scenario. Assessment of the additionality can be made based on evaluating the project using the performance standard approach as described below. Project proponents utilizing this methodology shall consult the latest version of the ACR's *Standard*, which may be updated from time to time.

To qualify as additional, the project must

- Pass a regulatory additionality test; and
- Exceed a performance standard

1. Surplus to Regulations (Regulatory Surplus Test)

In order to pass the regulatory surplus test, a project must not be mandated by existing laws, regulations, statutes, legal rulings, or other regulatory frameworks in effect now, or as of the project start date, that directly or indirectly affect the credited GHG emissions associated with a project.

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 CO₂. 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 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.

2. Exceeds a Performance Standard

Projects are required to achieve a level of performance that, with respect to emission reductions or removals, or 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; 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.
- *Emissions rate or benchmark* (e.g., tonnes of CO₂e emission per unit of output): with examination of sufficient data to assign an emission rate that characterizes the industry, sector or subsector. The net GHG emissions/removals associated with the project activity, in excess of this benchmark, may be considered additional and credited.

Qualifying CCS projects are those that include the capture, transport, and storage of anthropogenic CO₂ in oil and gas reservoirs. Table 3-1 shows the number of operating power, gas processing, ethanol, hydrogen, ammonia, and ethylene oxide production plants that emit an estimated 6.9 million metric tonnes per day of CO₂ into the atmosphere. There are no power or hydrogen production plants with CCS that are currently in operation and only a small fraction of the gas processing, ethanol, ammonia, and ethylene oxide plants have CCS technologies. In total only 10 of nearly 3,700 industrial facilities currently have CCS. For some sources (e.g. power plants) that emit low concentrations of CO₂, there is significant research being undertaken to develop various types of capture technologies. However, there are no commercial-scale applications of these technologies.

Table 3-1 Industrial Plants in the US with CCS^{4 5 6}

Anthropogenic CO₂ Emission Source	No. of Plants	Estimated CO₂ Emissions (1,000 Metric tonnes per day)	No. of Plants with CCS
Fossil fuel-fired Power Plants	2,800	6,544	0
Gas Processing Plants	493	231	5
Ethanol Plants	200	46	2
Hydrogen Plants (non-refinery)	74	25	0
Hydrogen Plants (refinery)	70	55	0
Ammonia Plants	22	24	2
Ethylene Oxide Plants	10	7	1
TOTAL	3,669	6,932	10

Data on current injection rates of CO₂ during EOR operations in the US were reviewed to quantify adoption rates of anthropogenic CO₂ sequestration in the US.

Figure 3-2 shows the existing CO₂ pipeline system in the US that has evolved over the last thirty five years. The network connects natural and anthropogenic sources of CO₂ 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

⁴ The Emissions & Generation Resource Integrated Database for 2010, (EGRID2010), U.S. Environmental Protection Agency, December 2010

⁵ Natural Gas Processing Plants in the United States: 2010 Update, US Energy Information Administration, Jun 17, 2011

⁶ US Energy Information Administration at <http://www.eia.gov/electricity/annual/html/table3.9.cfm>

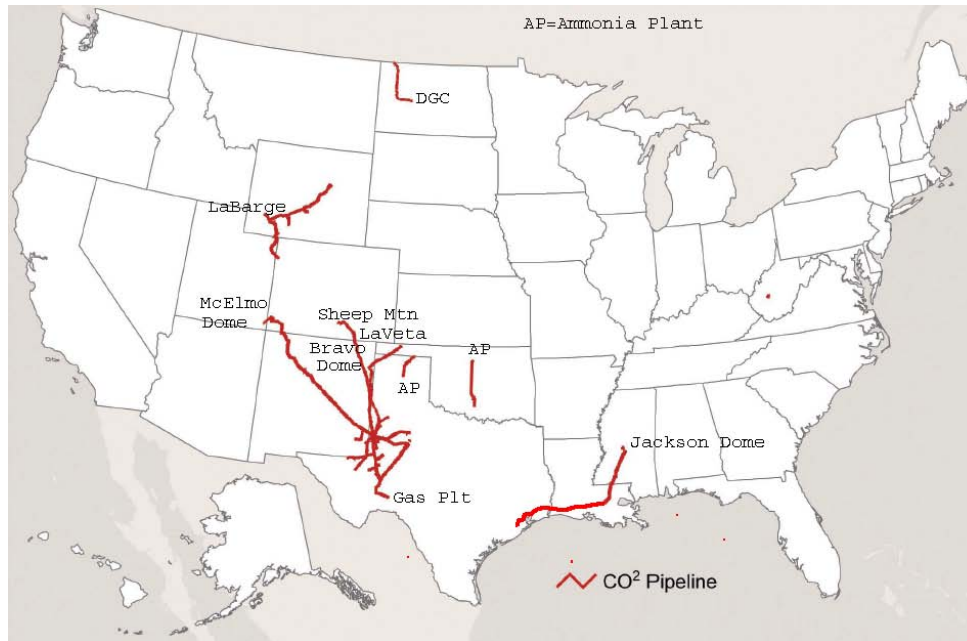


Figure 3-1 Major US CO₂ Pipelines

Table 3-2 provides a listing of these major sources of CO₂. Total CO₂ usage rates from both natural and anthropogenic sources are 3.1 billion cubic feet per day (bcfd). It includes approximately 80 percent or 2.44 bcfd obtained from natural sources with the remaining 20 percent or 0.655 bcfd being captured from anthropogenic sources.

The current anthropogenic CO₂ usage rate of 0.655 bcfd (34,000 metric tonnes per day) is significantly small (< 0.5 percent) when compared to the estimated total of 6.9 million metric tonnes per day of anthropogenic CO₂ that is emitted to the atmosphere from the industrial sources listed in Table 3-1. It indicates that the penetration levels for the practice of using anthropogenic CO₂ for EOR are extremely low.

The data in Tables 3-1 and 3-2 indicates that the adoption rates of CCS capture technologies for industrial sources as a whole and for individual source types are extremely low, and the injection of anthropogenic CO₂ in hydrocarbon reservoirs during EOR is not common practice.

Table 3-2 US Natural and Anthropogenic Sources of CO₂ for EOR

North American Sources	Usage Rates	
	MMscfd	1,000 metric tonnes per day*
Natural Sources (Domes)		
Mc Elmo Dome	1,200	62
Bravo & West Bravo Dome	290	15
Sheep Mountain & La Veta	50	3
Jackson Dome	900	47
Sub Total	2,440	126
Anthropogenic Sources		
Natural Gas Plants (5)	430	22
Coal Gasification	150	8
Ammonia Plants (2)	60	3
Ethylene Plant (1)	5	0.3
Ethanol Plants (2)	10	0.5
Sub Total	655	34
Total CO₂ Sources for EOR	3,095	160

*19,300 scf/metric tonne

Currently, there are no commercial scale DAC facilities. This technology is in various stages of bench-scale and pilot-scale development and testing.

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.

4.0 QUANTIFICATION METHODOLOGY

4.1 Baseline Emissions

Two approaches can be used to calculate baseline CO₂ emissions – Projection-based and Standards-based. To be conservative, the procedures do not calculate methane (CH₄) or nitrous oxide (N₂O) emissions.

Functional Equivalence. The implementation of CO₂ capture infrastructure may result in changes to energy consumption and/or product output, and impact the quantity of GHG emissions produced at the capture site. Since the calculation of baseline emissions involves collecting and using actual project data from the capture site, a project developer could inaccurately quantify emissions reductions from the CCS project if it does not appropriately maintain “functional equivalence” between the baseline and project and adjust applied data, as necessary.

For example, in some project configurations, incremental emissions associated with operating the capture system could yield an overall increase in CO₂ production and result in a larger volume of CO₂ captured and processed, relative to what the “primary process” would have emitted in the baseline. A power plant retrofitted with post-combustion CO₂ 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 CO₂ production. In this case, using actual measured CO₂ production values from the project to derive baseline emissions could 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 CO₂ as the baseline. This might occur if steam from the coal-fired boiler is directed toward the capture system to regenerate the CO₂ absorber rather than the power cycle. Therefore, while the capture system would not cause an increase in total CO₂ production, it could lead to the generation of less electricity. In this case, if a project developer 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 CO₂ 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 CO₂ emissions streams would likely be separate from the captured CO₂ from the primary process.

Project developers 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 impact of the CCS project and that the comparison between project and baseline emissions maintains “functional equivalence.”

4.1.1 Calculation Procedure for Projection-Based Baseline

The Projection-based baseline uses actual GHG emissions from the project to represent what would have occurred in the absence of CCS. The procedure involves multiplying the amount of actual CO₂ produced by the primary process, (which project developers measure immediately downstream of the primary process) by an “adjustment factor” that accounts for incremental changes in CO₂ produced by the capture equipment and included in the measured CO₂ stream. As discussed above, the adjustment factor is a part of the equation to maintain functional equivalence between the baseline and project. Project developers would determine the appropriate way to correct measured CO₂ emissions on a project-by-project basis and justify to the validation/verification body how the adjustment factors applied have maintained functional equivalence between the baseline and project scenarios.

For DAC facilities, baseline emissions are determined from the volume of gas and its CO₂ concentration measured at a suitable location in the capture process.

As provided in Equation 4.1, for combustion processes the mass of CO₂ could be determined from flue gas volume and composition measurements.

Equation 4.1: Total Annual Projection-based Baseline GHG Emissions

BE_{Projection-Based, y} = (Vol. Gas Produced_y x %CO₂ x ρCO₂) x 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 or for DAC facilities the volume of the captured gas measured at a suitable location in the process; volume measured at standard conditions, in each year (m ³ gas/yr).
%CO₂	= % 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).
ρCO₂	= 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). ⁷ 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 DAC facilities. Note: GHG emissions from the capture system are still attributable to the project activity and have to be quantified and included in project emissions as discussed in 4.2.1.

4.1.2 Calculation Procedure for Standards-based Baseline

The Standards-based baseline is calculated by multiplying an emissions intensity metric or “performance standard,” expressed as (tCO₂e/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), as provided in Equation 4.2.

An applicable performance standard may be set by regulation based on the type of facility generating the captured CO₂ emissions. Procedures for collecting data from the actual project to

⁷ This variable is included to maintain functional equivalence between the baseline and project.

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, regarding CCS projects that involve power generation, electricity may be used to operate the CO₂ 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 CO₂ capture. In this case, the project proponent shall use gross electricity production as the “output” instead of net electricity production.

Equation 4.2: Total Annual Standards-based Baseline Emissions

BE_{Standards-based} = BE_{performance standard} * Output_y	
Where,	
BE_{Standards-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) in the project condition in year y (units of output).

4.2 Project Emissions

CCS project emissions equal the sum of CO_{2e} emissions from CO₂ capture, transport, and storage, as shown in Equation 4.3.⁸

⁸ The methodology does not include calculation procedures to determine mobile source emissions, as it is generally recognized that a change in mobile emissions would not impact the calculated reductions from the project.

Equation 4.3: Total Project Emissions

$PE_y = PE_{\text{Capture}, y} + PE_{\text{Transport}, y} + PE_{\text{Storage-P}, y}$	
Where,	
PE_y	= Project emissions from CCS project in year y (tCO ₂ e/yr).
$PE_{\text{Capture}, y}$	= Project emissions from CO ₂ capture and compression in year y (tCO ₂ e/yr). Refer to Section 4.2.1.
$PE_{\text{Transport}, y}$	= Project emissions from CO ₂ transport in year y (tCO ₂ e/yr). Refer to Sections 4.2.2. and 4.2.3
$PE_{\text{Storage-P}, y}$	= Project emissions from CO ₂ injection and storage in year y (tCO ₂ e/yr). Refer to Sections 4.2.4 and 4.2.5.

4.2.1 Calculation Procedures for CO₂ Capture

The calculation procedure for the CO₂ capture process reflects the delineation of the boundary of the capture site, which encompasses the source of CO₂, as well as auxiliary equipment associated with the CO₂ capture and compression systems. In many cases, the primary process that generates the CO₂ is part of a large industrial complex (e.g., a refinery, bitumen upgrader, chemical plant, gas processing plant, etc.) with many processes unaffected by or independent of the CO₂ capture activities. Only those processes directly impacted by the CO₂ capture process are included in the quantification assessment. The boundary of the capture site extends to the point at which CO₂ is transferred to the pipeline operator.

The following equation outlines the methods for calculating emissions from the capture segment of CCS projects. This equation is applicable to pre-combustion capture, post-combustion capture, oxy-fuel capture and CO₂ capture at industrial sites.

Equation 4.4: Total Annual Project Emissions from the Capture Segment

$\mathbf{PE}_{\text{Capture}, y} = \mathbf{PE}_{\text{C-PP}, y} + \mathbf{PE}_{\text{C-Comb}, y} + \mathbf{PE}_{\text{C-Indirect Energy}, y}$	
Where,	
$\mathbf{PE}_{\text{Capture}, y}$	= Project emissions from CO ₂ capture and compression in each year (tCO ₂ e/yr).
$\mathbf{PE}_{\text{PP}, y}$	= 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 4.5.
$\mathbf{PE}_{\text{Comb}, y}$	= 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 ₂ e/yr). Refer to Equation 4.6.
$\mathbf{PE}_{\text{Indirect Energy}, y}$	= Project emissions from purchased electricity and thermal energy used to operate the CO ₂ capture and compression systems in each year (tCO ₂ e/yr). Refer to Equation 4.7.

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. For example, a post-combustion system might capture 90 percent of CO₂ created by a power production facility; thus, the ten 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 CO₂ from the primary process emitted to the atmosphere through vent stacks and fugitive releases from equipment at the capture and compression systems as “non-captured CO₂.”

Vented and fugitive emissions from capturing and compressing CO₂ include both intentional and unintentional releases. CO₂ may be vented through dedicated vent stacks during normal operation, process upsets, or shutdowns. Fugitive emissions may arise from leakage of CO₂ from equipment such as flanges, valves and flow meters.

The following equations account for the portion of CO₂ generated from the primary process that is not captured but emitted to the atmosphere. Project developers calculate emissions by subtracting CO₂ transferred to the transport segment of the CCS project from total CO₂, CH₄, and N₂O produced from the primary process. Table 5-5 provides the monitoring parameters to calculate total annual CO₂ produced from the primary process and transferred to the CO₂ pipeline; it also provides the monitoring parameters necessary for calculating the CH₄ and N₂O emissions from the primary process.

Equation 4.5 Non-Captured CO₂e Emissions from the Primary Process at the Capture Site

$PE_{C-PP,y} = CO_2 \text{ Produced}_{PP,y} + CO_2e \text{ Produced}_{PP,y} - CO_2 \text{ Transferred}_{PP,y}$	
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).
$CO_2 \text{ Produced}_{PP,y}$	= 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 4.5a. ⁹
$CO_2e \text{ Produced}_{PP,y}$	= Total CH ₄ and N ₂ O produced from the primary process in each year (tCO ₂ /yr). Only applicable to CO ₂ capture projects that use combustion to produce CO ₂ for capture. Refer to Equation 4.5b.
$CO_2 \text{ Transferred}_{PP,y}$	= 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 Equation 4.5c.

⁹ For gasification projects, the total mass of CO₂ 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 CO₂.

Equation 4.5a: Primary Process CO₂ Emissions¹⁰

$$\text{CO}_2 \text{ Produced}_{\text{PP}, y} = (\text{Vol. Gas Produced}, y \times \% \text{CO}_2 \times \rho \text{CO}_2)$$

Where,

CO₂ 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).
%CO₂	=	% CO ₂ in the gas stream, measured immediately downstream of the primary process, at standard conditions, each year (% volume).
ρCO₂	=	Density of CO ₂ at standard conditions = 0.00190 metric ton/m ³ .

Equation 4.5b: Primary Process CH₄ and N₂O Emissions^{11 12}

$$\text{CO}_2\text{e Produced}_{\text{PP}, y} = \sum(\text{Fuel}_i \times \text{EF CH}_4_{\text{Fuel } i}) \times \text{CH}_4\text{-GWP} + \sum(\text{Fuel}_i \times \text{EF N}_2\text{O}_{\text{Fuel } i}) \times \text{N}_2\text{O-GWP}$$

Where,

CO₂e Produced_{PP, y}	=	Gross amount of CH ₄ and N ₂ O 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 CH₄_{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 N₂O_{Fuel i}	=	N ₂ O emission factor for combustion of fossil fuel i (e.g., tN ₂ O/m ³ or tN ₂ O/kg of fuel).
CH₄-GWP	=	Global Warming Potential of methane = 21.
N₂O-GWP	=	Global Warming Potential of N ₂ O = 310.

¹⁰ See Appendix A for a fuel-based method to calculate emissions from stationary combustion projects which occur during the primary process where direct measurement of CO₂ is not possible.

¹¹ Applicable to CO₂ capture projects which combust fossil fuels in the primary process.

¹² Emission factors for CH₄ and N₂O emissions from combustion of fossil fuels are available at www.epa.gov/climateleaders/guidance/ghg-emissions.html

Equation 4.5c: CO₂ Captured and Input into CO₂ Transport Pipeline

CO₂ Transferred_y = Vol. Gas Transferred_y x %CO₂ x ρCO₂	
Where,	
CO₂ 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).
%CO₂	= % CO ₂ in the gas stream measured at the input to the pipeline, at standard conditions (% volume).
ρCO₂	= Density of CO ₂ at standard conditions = 0.00190 metric ton/ m ³ .

Emissions quantification at the CO₂ capture site also includes stationary combustion and electric-drive units to support the capture and compression processes, such as cogeneration units, boilers, heaters, engines, 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 CO₂-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 CO₂ capture process.

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 CO₂ capture and compression.

Equation 4.6: Capture Site Emissions of CO₂, CH₄, and N₂O from Stationary Combustion Associated with Auxiliary Equipment¹³

$$PE_{C-Comb, y} = \sum(Fuel_i \times EF_{CO_2, Fuel_i}) + \sum(Fuel_i \times EF_{CH_4, Fuel_i}) \times CH_4-GWP + \sum(Fuel_i \times EF_{N_2O, Fuel_i}) \times N_2O-GWP$$

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 ₂ e/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).
EF_{CO₂, 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_{CH₄, 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_{N₂O, Fuel_i}	=	N ₂ O emission factor for combustion of fossil fuel i (e.g., tN ₂ O/m ³ or tN ₂ O/ metric ton of fuel).
CH₄-GWP	=	Global Warming Potential of methane = 21.
N₂O-GWP	=	Global Warming Potential of N ₂ O = 310.

For some CCS project configurations, operating the CO₂ 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 CO₂-rich absorbent used 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.

¹³ Emission factors for CO₂, CH₄, and N₂O emissions from combustion of fossil fuels are available at www.epa.gov/climateleaders/guidance/ghg-emissions.html

Indirect emissions associated with purchased energy inputs used to operate the CO₂ capture and compression processes may need to be quantified according to equations 4.7, 4.7a, 4.7b, and 4.7c. Table 5-5 provides the monitoring parameters to calculate CO₂ emissions from purchased and consumed electricity, steam and heat.

Emission Factor for Electricity Generation (EF_{Electricity})

In Equation 4.7a, 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.¹⁴ As of adoption of this methodology, the latest release is eGRID2012 version 1.0, containing data through 2009. The latest published version of eGRID shall always be used.

eGRID2012 provides data organized by power control area (PCA), North American Electric Reliability Corporation (NERC) region, eGRID subregion, U.S. state, and other levels of aggregation. The PCA, eGRID subregion, and NERC region data are based on electricity generation, transmission and distribution areas so effectively represent the emissions associated with the mix of GHG-emitting and non-emitting resources used to serve electricity loads in those areas.

The Project Proponent shall use emission factors from the latest version of eGRID available. The Proponent shall download, from the eGRID website, the data files spreadsheet. For eGRID2012 Version 1.0, this is called "eGRID2012V1_0_year 09 data.xls". Note the "Contents" tab shows the various levels of aggregation included in the other spreadsheet tabs.

The emission factor is selected in the order of preference below; i.e. if the PCA 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.

¹⁴ See <http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html>.

1. In eGRID2012 version 1.0, the PCAL09 tab has data for 119 Power Control Areas across the United States. This methodology considers those PCA emission factors to be the most precise representation of emissions and thus requires the PCA emission rate to be used as long as the PCA can be identified. In the PCAL09 tab, look up the appropriate PCA in the left-hand column and scroll across to the column entitled “PCA annual CO₂ equivalent total output emission rate (lb/MWh)”. Divide this value by 2,205 to convert it to units of tCO₂e/MWh.
2. If the PCA is not known, use the eGRID subregion data in the SRL09 tab. This includes emission factors for 26 eGRID subregions covering the United States (see “eGRID2012_eGRID subregion representational map,” reproduced in Annex B). Look up the appropriate eGRID subregion in the left-hand column and scroll across to the column entitled “eGRID subregion annual CO₂ equivalent total output emission rate (lb/MWh)”. Divide this value by 2,205 to convert it to units of tCO₂e/MWh.
3. If the PCA 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 ST09 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 CO₂ equivalent total output emission rate (lb/MWh)”. Divide this value by 2,205 to convert it to units of tCO₂e/MWh.

Equation 4.7: CO₂ 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 ₂ e/yr).
$PE_{Elec, y}$	= Project emissions from grid electricity used to operate the CO ₂ capture and compression facilities in each year (tCO ₂ e/yr). Refer to Equation 4.7a.
$PE_{Cogen, y}$	= 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 ₂ e/yr). Refer to Equation 4.7b.

Equation 4.7a: CO₂ 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 ₂ e/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) PCA, eGRID subregion, or State (tCO ₂ e/MWh).

Equation 4.7b: CO₂, CH₄, N₂O Emissions from Purchased and Consumed Steam and /or Heat¹⁵

$$\mathbf{PE}_{\text{Cogen, y}} = \sum(\mathbf{Fuel}_i \times \mathbf{EF}_{\text{CO}_2 \text{ Fuel } i}) + \sum(\mathbf{Fuel}_i \times \mathbf{EF}_{\text{CH}_4 \text{ Fuel } i}) \times \mathbf{CH}_4\text{-GWP} \\ + \sum(\mathbf{Fuel}_i \times \mathbf{EF}_{\text{N}_2\text{O} \text{ Fuel } i}) \times \mathbf{N}_2\text{O-GWP}$$

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 ₂ e/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 4.7c.
EF_{CO₂ 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_{CH₄ 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_{N₂O Fuel i}	=	N ₂ O emission factor for combustion of fossil fuel i (e.g., tN ₂ O/m ³ or tN ₂ O/kg of fuel).
CH₄-GWP	=	Global Warming Potential of methane = 21.
N₂O-GWP	=	Global Warming Potential of N ₂ O = 310.

¹⁵ Emission factors for CO₂, CH₄, and N₂O emissions from combustion of fossil fuels are available at www.epa.gov/climateleaders/guidance/ghg-emissions.html

Equation 4.7c: Apportionment of Cogen Emissions by Product

$$\text{Fuel}_i = \text{Total Fuel}_{\text{Cogen}} \times [(\text{Heat}_{\text{CCS Project}} + \text{Electricity}_{\text{CCS Project}}) / (\text{Heat}_{\text{Cogen}} + \text{Electricity}_{\text{Cogen}})]$$

Where,

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 metric tons/yr). ¹⁶
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 each year (e.g., m ³ /yr or metric tons/yr).
Heat_{CCS Project}	=	Quantity of thermal energy purchased from the third party cogeneration unit to operate the CO ₂ capture facilities (MWh/year).
Electricity_{CCS Project}	=	Quantity of electricity purchased from the third party cogeneration unit to operate the CO ₂ capture and compression facilities (MWh/year).
Heat_{Cogen}	=	Total quantity of thermal energy generated by the third party cogeneration unit (MWh/year).
Electricity_{Cogen}	=	Total quantity of electricity generated by the third party cogeneration unit (MWh/year).

4.2.2 Calculation Procedures for CO₂ Transport

The GHG emission quantification approach for the transport segment of a CCS project includes the full pipeline system from the CO₂ delivery point at the capture site (downstream of the compressor) to the CO₂ delivery point at the storage site. The calculation methodology does not apply to CO₂ transported in containers (e.g., by truck, rail or ship).¹⁷

The emissions quantification procedures in this section apply to a CCS project that includes a dedicated pipeline moving CO₂ from the capture site to the storage site. For CO₂ transport using

¹⁶ The CO₂ 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

¹⁷ For CO₂ transported in containers, quantification guidance can be found EPA Subpart RR, 40 CFR § 98.443.

a network of pipelines, where project CO₂ can be commingled with CO₂ 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 CO₂ transport include CO₂ emissions from venting and fugitive releases as well as CO₂, CH₄ and N₂O emissions from stationary combustion and electricity use. Table 5-5 provides monitoring parameters to calculate emissions from CO₂ transport.

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

Equation 4.8: Total Project Emissions from the Transport Segment

$PE_{\text{Transport}, y} = PE_{\text{T-Comb}, y} + PE_{\text{T-VF}, y} + PE_{\text{T-Electricity}, y}$	
Where,	
$PE_{\text{Transport}, y}$	= Project emissions from CO ₂ transport in year y (tCO _{2e} /yr).
$PE_{\text{T-Comb}, y}$	= 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 4.9.
$PE_{\text{T-VF}, y}$	= Project emissions from venting events and fugitive releases from the CO ₂ pipeline and associated equipment in each year (tCO _{2e} /yr). Refer to Equation 4.10.
$PE_{\text{T-Electricity}, y}$	= Project emissions from electricity consumed to operate equipment the CO ₂ pipeline and associated equipment in each year (tCO _{2e} /yr). Refer to Equation 4.11.

A variety of stationary combustion equipment are used to maintain and operate the CO₂ pipeline. Stationary combustion equipment that are a part of CO₂ 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 to maintain and operate the CO₂ transportation infrastructure are quantified according to the following equation.

Equation 4.9: CO₂, CH₄, N₂O Emissions from Stationary Combustion for CO₂ Transport¹⁸

$$PE_{T-Comb, y} = \sum(Fuel_i \times EF_{CO_2, Fuel_i}) + \sum(Fuel_i \times EF_{CH_4, Fuel_i}) \times CH_4-GWP + \sum(Fuel_i \times EF_{N_2O, Fuel_i}) \times N_2O-GWP$$

Where,

PE_{T-Comb, y}	=	Project emissions from combustion of fossil fuels in stationary equipment to maintain and operate the CO ₂ transport infrastructure in each year (tCO ₂ e/yr).
Fuel_i	=	Volume or mass of each type of fuel, by fuel type i, used to maintain and operate the CO ₂ transport infrastructure in each year (e.g., m ³ /yr or kg/yr).
EF_{CO₂, 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_{CH₄, 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_{N₂O, Fuel_i}	=	N ₂ O emission factor for combustion of fossil fuel i (e.g., tN ₂ O/m ³ or tN ₂ O/ metric ton of fuel).
CH₄-GWP	=	Global Warming Potential of methane = 21.
N₂O-GWP	=	Global Warming Potential of N ₂ O = 310.

This methodology presents a mass balance approach to calculate transport-related vented and fugitive CO₂ emissions. Venting and fugitive emissions of CO₂ are grouped together in the mass balance determination.

The following equation is used to quantify venting and fugitive emissions from the CO₂ pipeline according to the mass balance method.

¹⁸ Emission factors for CO₂, CH₄, and N₂O emissions from combustion of fossil fuels are available at www.epa.gov/climateleaders/guidance/ghg-emissions.html

Equation 4.10: Vented and Fugitive CO₂ Emissions from CO₂ Transport

$$PE_{T-VF,y} = CO_2 \text{ Received}_{\text{Capture},y} - CO_2 \text{ Supplied}_{\text{Storage},y}$$

Where,

PE_{T-VF,y} = Project emissions from venting events and fugitive releases from the CO₂ pipeline and associated equipment in each year (tCO₂e/yr).

CO₂ Received_{Capture,y} = CO₂ captured and input into the pipeline, metered at the point of transfer with the capture site in each year (tCO₂/yr). Refer to Equation 4.10a.

CO₂ Supplied_{Storage,y} = CO₂ supplied to the storage site operator, metered at the point of transfer with the storage site in each year (tCO₂/yr). Refer to Equation 4.10b.

Equation 4.10a: CO₂ Captured and Input into CO₂ Pipeline

$$CO_2 \text{ Received}_{\text{Capture},y} = Vol. \text{ Gas Received},y \times \%CO_2 \times \rho_{CO_2}$$

Where,

CO₂ Received_{Capture,y} = CO₂ captured and input into the pipeline, metered at the point of transfer with the capture site in each year (tCO₂/yr).

Vol. Gas Received,y = CO₂ captured and input into the pipeline, metered at the point of transfer with the capture site in each year (m³ CO₂/yr).

%CO₂ = % CO₂ in the gas stream measured at the point of transfer with the capture site (% volume).

ρCO₂ = Density of CO₂ at standard conditions = 0.00190 metric ton/m³.

Equation 4.10b: CO₂ Transferred from CO₂ Pipeline to CO₂ Storage Site

CO₂ Supplied $_{\text{Storage, y}} = \text{Vol. Gas Supplied, y} \times \% \text{CO}_2 \times \rho \text{CO}_2$	
Where,	
CO₂ Supplied $_{\text{Storage, y}}$	= 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 (m ³ CO ₂ /yr).
%CO₂	= % CO ₂ in the gas stream measured at the transfer with the storage site (% volume). ¹⁹
ρCO₂	= Density of CO ₂ at standard conditions = 0.00190 metric ton/ m ³ .

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. 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 CO₂ storage segment calculation procedures.

In some CCS project configurations, grid electricity may be purchased to operate the CO₂ transport infrastructure. In particular, electric-drive compressors may be used for supplemental compression along the CO₂ pipeline, where grid connectivity permits. The indirect emissions associated with purchased electricity to operate the CO₂ transport infrastructure can be quantified according to the following equation.

¹⁹ Composition of gas delivered to storage site is assumed to be same composition as the gas at inlet to the pipeline.

Equation 4.11: CO₂e Emissions from Electricity Consumption for CO₂ Transport

		$PE_{T-Elec, y} = \text{Electricity} \times EF_{\text{Electricity}}$
Where,		
$PE_{T-Elec, y}$	=	Project emissions from electricity usage from equipment used to operate the CO ₂ transport infrastructure in each year (tCO ₂ e/yr).
Electricity	=	Total metered electricity usage from equipment used to operate the CO ₂ transport infrastructure in each year (MWh).
$EF_{\text{Electricity}}$	=	Emission factor for electricity generation in the relevant region, by (in order of preference) PCA, eGRID subregion, or State (tCO ₂ e/MWh).-See Section 4.2.1 for estimation procedures.

4.2.3 Calculating CO₂ Transport Emissions According to System-Wide Emission Factors.

The emissions quantification procedure for the CO₂ transport segment corresponds with a CCS project that includes a dedicated pipeline moving CO₂ from the capture site to the storage site. However, CCS projects could use pipeline systems that carry streams of CO₂ from multiple capture sites to one or more geologic storage reservoirs. Thus, an emissions accounting approach that pro-rates CO₂ losses according to a proportional use of a pipeline's annual throughput or a share of a storage site's annual CO₂ injection is appropriate. The project developer shall work with the entity responsible for the CO₂ pipeline to obtain a reasonable system-wide emission factor (percent losses of the total) and calculate its CO₂ losses (emissions). For example, if a pipeline operator has sufficient records of CO₂ imported and exported out of its system, it could determine a fugitive CO₂ factor according to a mass-balance approach. Pipeline operators could also derive a system-wide fugitive CO₂ emissions factor from a comprehensive component count assessment.²⁰ For completeness, a comprehensive loss factor should also incorporate vented and stationary combustion emission sources within the appropriate GHG assessment boundary, and emissions from purchased electricity.

²⁰ Project developers could derive a CO₂ pipeline emission factors based on natural gas transmission factors and then convert from methane to CO₂ (emissions CO₂/kilometer of pipeline). The American Petroleum Institute's Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry (2004) is one source for a pipeline emissions factor.

4.2.4 Calculation Procedures for CO₂ Storage

The emissions calculation procedures for CO₂ storage cover direct CO₂, CH₄, and N₂O emissions from stationary combustion; CO₂ and CH₄ emissions from venting and fugitive releases to the atmosphere; and indirect CO₂e emissions from purchased electricity use. The procedures also account for any CO₂ that is produced with the hydrocarbons and transferred offsite (i.e., the CO₂ is not re-injected into a reservoir that is within the project boundary) and leakage of injected CO₂ from the reservoir to the atmosphere. GHG sources include CO₂ receiving, injecting, recycling and re-injection equipment; CO₂ injection and production wells, hydrocarbon processing and storage facilities; and the CO₂ storage reservoir.

The emissions quantification methodology for CO₂ storage includes all emissions sources located between the point of transfer with the CO₂ pipeline up to and including the injection wells. It also incorporates producing wells and surface facilities related to the hydrocarbon gathering, storage and separation facilities and the infrastructure used to process, purify and compress CO₂ and other gases produced from the formation, and re-inject it back into the formation. Additionally, CO₂ entrained in or dissolved in hydrocarbons (crude oil or natural gas) or waste water 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 enhanced oil and gas recovery formations are accounted for by using common quantification methods based on the quantities and types of energy inputs. Vented CO₂ emissions from surface facilities are quantified on an event basis. Fugitive CO₂ emissions from injection wells and surface facilities are calculated according to a component count approach. The method to calculate leaked CO₂ from the geologic storage reservoir to the atmosphere, should it occur, would be reservoir-specific and is addressed in Section 4.2.5.

The methodology does not treat CO₂ produced from wells at enhanced oil or gas recovery operations that is recycled and re-injected into the storage formation as an emission, provided the CO₂ remains within the closed loop system and is thus prevented from entering the atmosphere. Unintentional CO₂ releases from the recycle system (including from production wells, gas

separation and cleaning equipment) are treated as fugitive emissions and accounted for in Equation 4.20. Intentionally vented CO₂ in the recycle system (for operational purposes) is treated as a vented emission and accounted for in Equation 4.19.

The following equation outlines the methods for calculating emissions from CO₂ storage. Table 5-5 provides monitoring parameters for calculating emissions from CO₂ storage.

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Equation 4.17: Total Project Emissions from CO₂ Storage

$$\begin{aligned} PE_{\text{Storage-P}, y} = & PE_{\text{S-P-Comb}, y} + PE_{\text{S-P-Vent}, y} + PE_{\text{S-P-Fug}, y} + PE_{\text{S-P-Elec}, y} + PE_{\text{S-P-CO}_2 \text{ Transfer}} \\ & + PE_{\text{S-P-Leakage}, y} \end{aligned}$$

Where,

- PE_{Storage-P, y}** = Project emissions from CO₂ injection and storage in each year (tCO₂e/yr).
- PE_{S-P-Comb, y}** = Project emissions from combustion of fossil fuels in stationary equipment at the storage site – e.g., to maintain and operate the CO₂ handling and injection wells, CO₂ recycling devices, and associated hydrocarbon production facilities in each year (tCO₂e/yr). Refer to Equation 4.18.
- PE_{S-P-Vent, y}** = Project emissions from venting of CO₂ at the injection wells or other surface facilities located between the point of transfer with the CO₂ pipeline and the injection wells in the formation; at the producing wells; at the hydrocarbon gathering processing and storage facilities; or at the CO₂ processing and recycling facilities in each year (tCO₂e/yr). Refer to Equation 4.19.
- PE_{S-P-Fug, y}** = Project emissions from fugitive releases of CO₂ or CH₄ at the injection wells or other surface facilities located between the point of transfer with the CO₂ pipeline and the injection wells; at the producing wells; at the hydrocarbon gathering processing and storage facilities; at the CO₂ processing and recycling facilities; and from CO₂ entrained in hydrocarbons or water produced from the formation and distributed off-site in each year (tCO₂e/yr). Refer to Equation 4.20.
- PE_{S-P-Elec, y}** = Project emissions from consumption of electricity used to operate equipment at the producing formation in each year (tCO₂e/yr). Refer to Equation 4.21.
- PE_{S-P-CO₂ Transfer}** = Produced CO₂ from an enhanced oil or gas recovery operation transferred offsite in each year (tCO₂/yr). Refer to Equation 4.22.
- PE_{S-P-Leakage, y}** = Project emissions from leakage of injected CO₂ from the geologic storage reservoir in the producing formation to the atmosphere in each year (tCO₂e/yr). For information on accounting for CO₂ leakage emissions from geologic storage formations to the atmosphere see Section 4.2.6.

Various types of stationary combustion equipment may be used to maintain and operate the CO₂ injection, storage, processing and recycling facilities and to operate the enhanced oil and gas

recovery facilities (e.g., batteries, gathering 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 CO₂ injection and storage facilities.²¹

Equation 4.18: CO₂, CH₄, N₂O Emissions from Stationary Combustion for CO₂ Storage²²

$$PE_{S-P-Comb,y} = \sum(Fuel_i \times EF_{CO_2, Fuel_i}) + \sum(Fuel_i \times EF_{CH_4, Fuel_i}) \times CH_4-GWP + \sum(Fuel_i \times EF_{N_2O, Fuel_i}) \times N_2O-GWP$$

Where,

PE_{S-P-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 ₂ e/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_{CO₂, 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_{CH₄, 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_{N₂O, Fuel i}	=	N ₂ O emission factor for combustion of fossil fuel i (e.g., tN ₂ O/m ³ or tN ₂ O/kg of fuel).
CH₄-GWP	=	Global Warming Potential of methane = 21.
N₂O-GWP	=	Global Warming Potential of N ₂ O = 310.

Venting may occur at the injection wells or at other surface facilities, located between the CO₂ transfer meter at the pipeline and the injection wells. 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 CO₂ for re-injection into the formation. Planned venting may take place during

²¹ Appendix A provides a procedure for calculate emissions from combusting hydrocarbons produced at the formation (e.g., in flares).

²² Emission factors for CO₂, CH₄, and N₂O emissions from combustion of fossil fuels are available at www.epa.gov/climateleaders/guidance/ghg-emissions.html

shutdowns and maintenance work, while unplanned venting may occur during upsets to operations. Venting events should be logged.

The following equation can be used to calculate vented emissions from the injection wells and other surface facilities at the CO₂ storage site.

Equation 4.19: Vented CO₂e Emissions from CO₂ Storage

$PE_{S-P-Vent, y} = \sum_{j=1}^2 \sum_{i=1}^I N_{Blowdown\ i} * V_{Blowdown\ i} * \%GHG_j * \rho_{GHG_j} * GWP_j * 0.001$	
Where,	
$PE_{S-P-Vent, y}$	= Project emissions from vented CO ₂ at the injection wells or other surface facilities located between the point of transfer with the CO ₂ pipeline and the injection wells in the producing formation; 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 ₂ e/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).
$\%GHG_j$	= 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 .
$\rho_{GHG\ j}$	= Density of relevant GHG (CO ₂ or CH ₄) at standard conditions in kg/m ³ or kg/ft ³ . At standard conditions $\rho_{CO_2} = 0.0538\text{ kg/ft}^3$ and $\rho_{CH_4} = 0.0196\text{ kg/ft}^3$. ²³
GWP_j	= 100 year Global Warming Potential of relevant GHG (For CO ₂ =1 and for CH ₄ =21).
0.001	= Conversion factor to convert from kg to metric tons.

²³ For CO₂ Injection pump blowdowns it may be necessary to use the density of CO₂ 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.

Fugitive emissions of CO₂, and in some cases methane, may occur at the injection wells or at other surface facilities, located between the CO₂ pipeline transfer meter and the injection wells. Fugitive emissions could also occur at production wells, the hydrocarbon production and storage facilities, and/or at the facilities used to process and recycle the produced CO₂ 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 CO₂ entrained or dissolved in produced oil, water or gas that is transferred from the hydrocarbon recovery facilities to downstream users.

Fugitive CO₂ and CH₄ emissions from injection wells and other surface equipment are calculated on a component count approach. Fugitive emissions of CO₂ entrained in or dissolved in hydrocarbon liquids or gases or water produced from the formation and distributed off-site are calculated based on quantities of crude oil, water and gas produced and the CO₂ content of each product.

The following equation is used to calculate fugitive emissions from the injection wells and other surface facilities at the CO₂ storage site.

Equation 4.20: Fugitive CO₂e Emissions from Wells and Surface Equipment

$$PE_{S-P-Fugitive, y} = PE_{S-P-Fug-Equipment, y} + PE_{S-P-Fug-Entrained CO_2, y}$$

Where,

PE_{S-P-Fugitive, y} = Project emissions from fugitive releases of CO₂ or CH₄ at the injection wells or other surface facilities located between the point of transfer with the CO₂ pipeline and the injection wells; at the producing wells; at the hydrocarbon gathering processing and storage facilities; at the CO₂ processing and recycling facilities; and from CO₂ entrained in hydrocarbons or water produced from the formation and distributed off-site in each year (tCO₂e/yr).

PE_{S-P-Fug-Equipment, y} = Fugitive emissions of CO₂ (and CH₄ if relevant) from equipment located at the injection wells or other surface facilities located between the point of transfer with the CO₂ pipeline and the injection wells; at the producing wells; at the hydrocarbon gathering processing and storage facilities; and at the CO₂ processing and recycling facilities in each year (tCO₂e/yr). Refer to Equation 4.20a.

PE_{S-P-Fug-Entrained CO₂, y} = Fugitive emissions of CO₂ 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 (tCO₂/yr). Refer to Equation 4.20b.

Equation 4.20a: CO₂ & CH₄ Fugitive Emissions from Equipment Leaks

$$PE_{S-P-Fug-Equipment, y} = \sum_{j=1}^2 \sum_{i=1}^I Count_s * EF_s * T_s * \%GHG_j * \rho_{GHGj} * GWP_j * 0.001$$

Where,

PE _{S-P -Fug-Equipment, y}	=	Fugitive of GHG 'i' (CO ₂ and CH ₄ , if relevant) from equipment located at the injection wells or other surface facilities located between the point of transfer with the CO ₂ pipeline and the injection wells; at the producing wells; at the hydrocarbon gathering processing and storage facilities; and at the CO ₂ processing and recycling facilities in each year (tCO ₂ e/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 with the CO ₂ pipeline and the injection wells; 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). ²⁴
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 _{GHGj}	=	Density of relevant GHG (CO ₂ or CH ₄) at standard conditions in kg/m ³ or kg/ft ³ . At standard conditions ρ _{CO2} = 0.0538 kg/ft ³ and ρ _{CH4} = 0.0196 kg/ft ³ .
GWP _j	=	100 year Global Warming Potential of relevant GHG (For CO ₂ =1 and for CH ₄ =21).
0.001	=	Conversion factor to convert from kg to metric tons.

²⁴ US Environmental Protection Agency. Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems, Final Rule: Subpart W. November 30, 2010

Equation 4.20b: CO₂ Fugitive Emissions Entrained in Produced Hydrocarbons

PE _{S-P-Fug-Entrained CO₂, y} =	(Vol. _{Gas Sold} x % CO ₂ _{Gas Sold} x ρ CO ₂ x 0.001) + (Mass _{Water Prod} x Mass Frac _{CO₂ in Water}) + (Mass _{Oil Prod} x Mass Frac _{CO₂ in Oil})
Where,	
PE _{S-P-Fug-Entrained CO₂,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).
ρ CO ₂ =	Density of CO ₂ at standard conditions (= 1.899 kg/m ³).
0.001 =	Conversion factor to convert from kg to metric tons.
Mass _{Water Prod} =	Mass of water produced from the formation 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).
Mass Frac _{CO₂ in Water} =	Mass fraction of CO ₂ in the water produced from the formation
Mass _{Oil Prod} =	Mass of crude oil and other hydrocarbons produced from the formation that CO ₂ is being injected into (metric tons/year).
Mass Frac _{CO₂ 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 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 CO₂ processing, compression, recycling and re-injection facilities.

For example, many enhanced oil and gas recovery projects install additional water pumping capacity to alternate water injection and CO₂ injection (water alternating gas (WAG) injection), which may also require electricity. Electric compression could be used to recycle produced CO₂ 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 vapors 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 with purchased electricity used to operate equipment at the enhanced oil and gas recovery operations are quantified according to the following equation.

Equation 4.21: CO₂e Emissions from Purchased Electricity Consumption for CO₂ Storage

$PE_{S-P-Elec, y} = Electricity * EF_{Electricity}$	
Where,	
$PE_{S-P-Elec, y}$	= Project emissions from electricity used to operate equipment at the CO ₂ storage site in each year (tCO ₂ e/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) PCA, eGRID subregion, or State (tCO ₂ e/MWh).-See Section 4.2.1 for estimation procedures

While CO₂ transferred out of the project boundary is not necessarily an emission to the atmosphere, project developers should nevertheless not account for it as if it were sequestered from the atmosphere.

For project accounting purposes to determine emissions reductions, the methodology does treat produced CO₂ from an enhanced oil or gas recovery operation that is transferred outside the project boundary as an emission. A project developer could move produced-CO₂ between

enhanced oil or gas 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 CO₂ is injected). Equation 4.22 presents the approach to calculate CO₂ transferred outside the project boundary.

Equation 4.22: CO₂ Transferred Outside Project Boundaries

$PE_{S-P-CO_2_Transfer} = Vol_{CO_2_Transfer} * \rho_{CO_2} * 0.001$	
Where,	
$PE_{S-P-CO_2_Transfer}$	= Produced CO ₂ from an enhanced oil or gas 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 (m ³ , ft ³).
ρ_{CO_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 Accounting for CO₂ Leakage from Geologic Storage Formations to the Atmosphere

Project developers must quantify fugitive CO₂ emissions from the geologic storage reservoir to the atmosphere, if they arise. As discussed in Section 2.2, leakage shall be monitored during the entire project term that includes the injection period and a time-period following the end of injection during which the reservoir is monitored for leakage to the atmosphere.

Detecting leakage from the geologic reservoir that could lead to emissions to the atmosphere might involve a comparison of deep subsurface operational monitoring results to reservoir and CO₂ injection models designed to predict the behavior of injected CO₂ within the storage complex. Project developers could also deploy monitoring devices to detect leakage of CO₂ at the surface, in which a comparison would be made between surface monitoring data and natural variations in CO₂ levels from organic matter and vegetation in the local environment. Other monitoring tools could also provide information on site performance indicators, the location and size of the CO₂ plume, environmental receptors, and other factors.

Project developers should establish CO₂ detection thresholds to calibrate monitoring systems in a manner that provides confidence in the monitoring program's ability to accurately confirm the effectiveness of the CO₂ storage complex.²⁵

Examples of conduits for CO₂ leaks to the atmosphere include CO₂ injection wells, oil or gas production wells (if applicable), monitoring wells and abandoned wells;²⁶ CO₂ could also escape the geologic containment complex through faults and fissures. However, for properly selected, operated, and closed CO₂ storage operations, fugitive CO₂ emissions from the geologic reservoir to the atmosphere should not occur.

For a CO₂ storage site in compliance with its CO₂ injection permit the value of the "CO_{2-z}" term in Equation 4.23 should be zero. That is, it is reasonable to expect that leakage to the atmosphere is not a threat and zero is an acceptable value for the "CO_{2-z}" term in Equation 4.23 if:

- "Conformance monitoring systems" show that the behavior of CO₂ within the injection zone in the storage complex agrees with modeled predictions and the key assumptions in the site permit are confirmed; and/or
- "Assurance monitoring systems" above (and, if appropriate to the site, lateral to) the injection zone in the storage complex do not detect injected CO₂.

In the event that leaks from the subsurface CO₂ containment complex do happen, which are not mitigated by the project developer and result in emissions to the atmosphere, project developers would quantify the fugitive CO₂ emissions on a site-by-site basis, according to a reasonable engineering approach. The project monitoring plan should include a strategy for detecting and quantifying any surface CO₂ leakage. In the event of containment failure, a simplified estimation to conservatively determine maximum leakage can be used, rather than requiring rigorous quantification.

²⁵ For a discussion of detection thresholds, see Benson, S. (2006). *Monitoring Carbon Dioxide Sequestration in Deep Geological Formations for Inventory Verification and Carbon Credits*. Richardson, TX: Society of Petroleum Engineers.

²⁶ Note: fugitive emissions from injection wells could be calculated according to Equation 4.15, as an emission factor is provided in US Environmental Protection Agency. Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems, Final Rule: Subpart W. November 30, 2010, see Appendix A.

Generally, the exercise to quantify the total amount of CO₂ emissions from the geologic storage complex, which the subsurface monitoring systems indicate will enter the atmosphere (or the surface systems show have crossed from the subsurface to the surface), will involve computations that incorporate a range of information about the specific geologic reservoir, the CO₂ injection regime, modeling assumptions, and other variables.

The following general equation to account for fugitive CO₂ emissions from the CO₂ storage complex to the atmosphere 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 CO₂ emissions pathway, should a leak be detected.

Equation 4.23: Fugitive CO₂ Emissions from Underground CO₂ Storage Formations²⁷

$\text{CO}_{2\text{Leakage-NP}} = \sum_{z=1}^Z \text{CO}_{2z}$	
Where,	
$\text{CO}_{2\text{Leakage-NP}}$	= Total mass of CO ₂ emitted through subsurface leakage from the formation in year y (metric tons).
CO_{2z}	= Total mass of CO ₂ emitted through leakage pathway z in year y (metric tons).
z	= Leakage pathway.

4.3 Emission Reductions

Overall GHG emission reductions from the CCS project equal Baseline Emissions minus Project Emissions, as shown in Equation 4.24. Note that leakage emissions (if any) from the reservoir are covered under project emissions. The calculation procedures for the baseline emissions and project emissions are presented in the following sections.

²⁷ 40 CFR §98.443(e), Eq. RR-10, 40

Equation 4.24: Total Annual GHG Reductions

$$\text{GHG Reductions}_y = \text{BE}_y - \text{PE}_y$$

Where,

GHG Reductions_y = Total annual GHG reductions from the CCS project (tCO₂e/yr).

BE_y = Baseline CO₂e emissions in each year (from eq. 4.1 or 4.2, tCO₂e/yr).

PE_y = Project CO₂e emissions in each year (from eq. 4.3, tCO₂e/yr).

5.0 DATA COLLECTION AND MONITORING

5.1 Verification Period

The verification period can be defined at the discretion of the project proponent, provided it conforms to ACR's guidelines on verification 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 new ERTs.

5.2 Baseline Emissions Measurement

Baseline emission measurement parameters and considerations are summarized in Table 5-1 for the projection based and standards based calculation procedures. Details of the calculation procedures are included in Section 4.0.

Table 5-1 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 ₂ O excluded from the baseline quantification .	Section 4.1.1 Equation 4.1 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 generated in by the project (and used to calculate baseline emissions under a Projection-based baseline) may need to be adjusted to account for the incremental CO ₂ generated to meet the energy penalty required to capture CO ₂ , if the energy required to operate the CO ₂ capture process equipment is met through electricity or thermal energy generated from the same process as that produces 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 “parasitic load” from the CO ₂ capture equipment) by deducting 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.	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.
Standards Based Baseline	CO ₂ To be conservative, CH ₄ and N ₂ O excluded from the baseline quantification .	Section 4.1.2 Equation 4.2 The Standards-based baseline is calculated by multiplying an emissions intensity metric or “performance standard,” expressed as (tCO ₂ e/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” value used to calculate baseline emissions should be set to maintain functional equivalence between baseline emissions and project emissions and ensure that the quantified emissions reductions appropriately represents the impact of the CCS project.	Measurement of “output” based on the type of primary process. Output should be measured to account for the total output from the primary process that would have occurred in the absence of the project.

5.3 Project Emissions Measurements

Project emission sources and GHG measurement parameters are summarized in Table 5-2. Details of the calculation procedures are included in Section 4.0. In addition to measurement parameters shown in Table 5-2, 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 5.4.

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Table 5-2 Overview of Project Emissions Calculation Procedures

Emission Sources Type & GHGs	Description	Key Monitoring Parameters
CO₂ Capture		
Total Capture Emissions CO ₂ ; CH ₄ ; N ₂ O	Section 4.2.1, Equation 4.4. 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, Equations 4.5, 4.5a, 4.5b, 4.5c. 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. 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.	Total volume of gas produced from the primary process, and captured and input into the pipeline
Stationary Combustion CO ₂ ; CH ₄ ; N ₂ O	Section 4.2.1, Equation 4.5b, 4.6, 4.7b A fuel-based calculation method, which applies to <ol style="list-style-type: none"> 1) primary process CH₄ and N₂O emissions for projects that generate CO₂ for capture through combustion, and 2) equipment used to capture and compress CO₂, including cogeneration units, boilers, heaters, engines, turbines, flares, etc, which are owned and controlled by the capture site located at all capture sites. 3) 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 ₂ O	Section 4.2.1, Equation 4.7, 4.7a, 4.7b, 4.7c. 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
CO₂ Transport		

Emission Sources Type & GHGs	Description	Key Monitoring Parameters
Total Transport Emissions CO ₂ ; CH ₄ ; N ₂ O	Section 4.2.2, Equation 4.8. Total Project Emissions from CO ₂ transport, including vented, fugitive, stationary combustion, and purchased and consumed electricity.	N/A
Stationary Combustion CO ₂ ; CH ₄ ; N ₂ O	Section 4.2.2, Equation 4.9. 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, Equations 4.10, 4.10a, 4.10b. Vented and fugitive emissions 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. Venting and fugitive releases during CO ₂ transportation. 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”.	Metered quantities of CO ₂ input into the pipeline and delivered to storage site
Electricity Use (if required) CO ₂ ; CH ₄ ; N ₂ O	Section 4.2.2, Equation 4.11. 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
CO₂ Storage		
Total Storage Emissions – CO ₂ ; CH ₄ ; N ₂ O	Section 4.2.5, Equation 4.17 Total Project Emissions from CO ₂ storage including stationary combustion, vented, fugitive, and electricity consumption emissions.	N/A

Emission Sources Type & GHGs	Description	Key Monitoring Parameters
Stationary Combustion CO ₂ ; CH ₄ ; N ₂ O	Section 4.2.5, Equation 4.18. Emissions from fossil fuel combustion to operate equipment used to store CO ₂ in the oil and gas reservoir. 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). 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	Section 4.2.5, Equation 4.19 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. 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 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.	Number of venting events; volume of CO ₂ per event.
Fugitive CO ₂ (excluding CO ₂ emissions from geologic reservoir to atmosphere)	Section 4.2.5, Equations 4.20, 4.20a, 4.20b. 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 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

Emission Sources Type & GHGs	Description	Key Monitoring Parameters
Electricity Use CO ₂ ; CH ₄ ; N ₂ O	Section 4.2.5, Equation 4.21. Indirect emissions from electricity use at the CO ₂ storage site. Grid electricity may be used to operate pumps (e.g., for incremental water injection as part of a Water Alternating Gas (WAG) Injection processes), 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 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.	Metered quantity of electricity used to operate CO ₂ storage and recycling equipment
Transferred CO ₂ CO ₂	Section 4.2.5, Equation 4.22. While not technically an emission, CO ₂ transferred outside the project boundary (i.e., produced CO ₂ from an enhanced oil or gas recovery operation not re-injected but moved offsite) is deducted from claimed emissions reductions. If an enhanced oil and gas recovery 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 enhanced oil or gas operation transferred outside project boundary
CO₂ Storage – Geologic Reservoir		
Fugitive CO ₂ emissions from the geologic reservoir to the atmosphere	Section 4.2.6, Equation 4.23. For properly selected, operated, and closed CO ₂ storage operations, fugitive CO ₂ emissions from the geologic reservoir should happen only in extraordinary circumstances. Emissions would be calculated on a site-by-site basis according to a reasonable engineering approach. For CO ₂ storage, the project monitoring plan would include a strategy for detecting and quantifying any surface CO ₂ leakage – i.e., leakage to atmosphere estimated based on monitoring and measurements completed as part of the MRV plan.	Total mass of CO ₂ emitted through leakage pathways to atmosphere

Figure 5-1 and Table 5-3 show the points of measurement for a generic CCS project

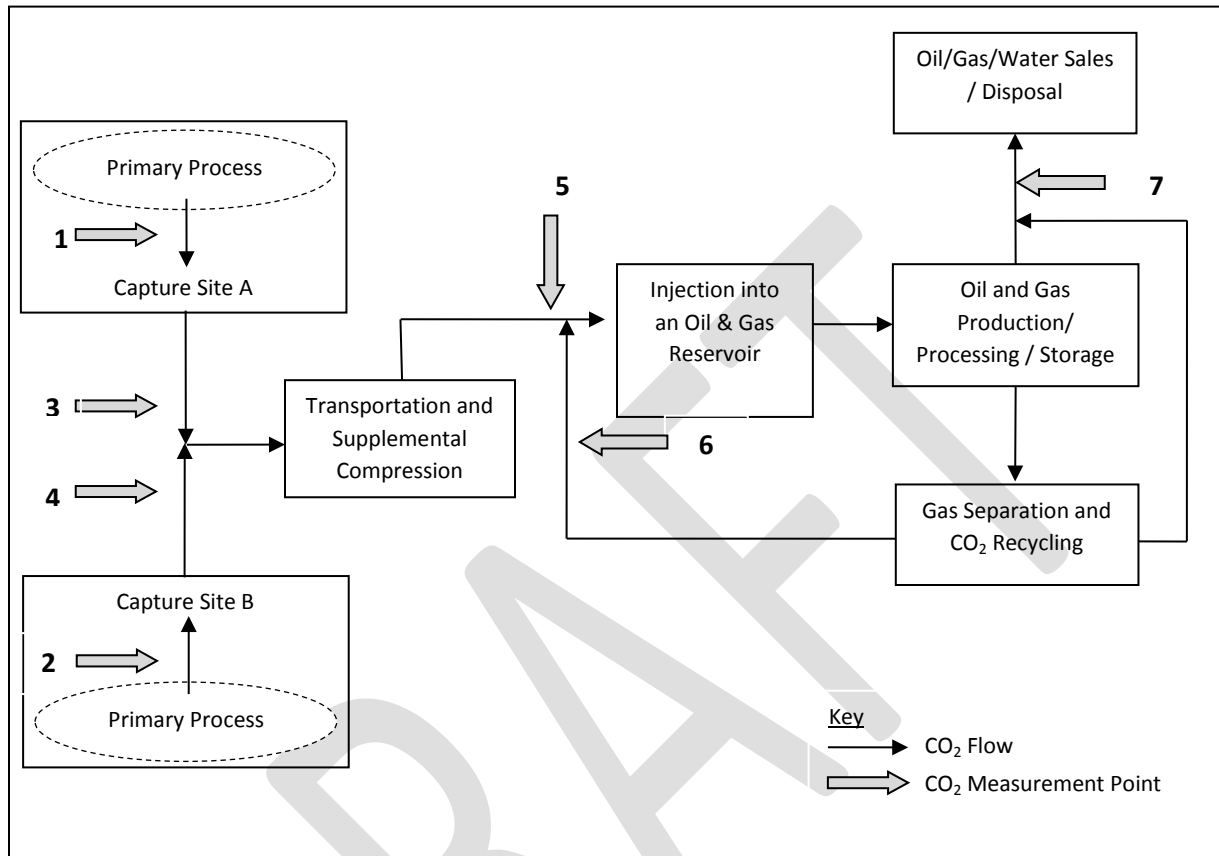


Figure 5-1 Points of CO₂ Measurement for the CCS Project²⁸

²⁸ Note that this diagram does not illustrate vented CO₂ emissions, fugitive CO₂ releases or CO₂ leakage from formations as the quantification of these emission sources generally does not rely on data from the CO₂ mass balance. For information on the quantification of emissions from these sources refer to the quantification section of the methodology.

Table 5-3 Points of CO₂ Measurement for the CCS Project (Associated with Figure 5-1)

Measurement Parameter	Description	Comment
Flow rate of CO ₂ gas stream	<p>Position 1 & 2. Flow meters located at the primary process to accurately measure the total amount of CO₂ produced (e.g., measurement of raw flue gas from a combustion process, measurement of total volume of syngas produced from a gasifier upstream of the shift reactor etc.).</p> <p>Position 3 & 4. Flow meters located at the input to the CO₂ pipeline such that they are downstream of all capture and compression equipment to account for any fugitive losses or venting.</p> <p>Position 5. Flow meters located at the point of transfer with the pipeline to ensure that a sales quality meter is used. It is also recommended that the quantity of CO₂ injected be measured close to the injection wellheads to add additional redundancy.</p> <p>Position 6. Flow meters located as close as possible to the connection with the main CO₂ pipeline that feeds the injection well(s) to accurately determine the total amount of CO₂ that is recycled.</p> <p>Position 7. Flow meters located at a point to measure the total volume of gas produced from the formation and distributed from the storage site (e.g., input into a gas gathering system or sold). This measurement should account for entrained CO₂ in the associated gas/solution gas that has been produced from the formation that CO₂ is being injected into.²⁹</p>	<p>Meter readings shall be temperature and pressure compensated such that the meter output is set to standard reference temperatures and pressures (e.g., 60°F and 1atm).</p> <p>Flow meters shall be placed a sufficient distance from any obstructions to ensure accurate flow measurements.</p> <p>Flow meters shall be calibrated quarterly or according to manufacturer specifications if more frequent calibrations are recommended by the manufacturer. See Section 7.0 QA/QC procedures</p> <p>Continuous measurement of the gas flow rate, where continuous measurement is commonly defined as one measurement every 15 minutes or less. If data are missing, follow procedures for estimating missing data contained in USEPA Subpart RR regulations³⁰</p>

²⁹ Natural gas pipelines often allow for up to 2% CO₂ in natural gas, and if the natural gas originates from the producing formation that CO₂ is being injected into, then the combustion of this natural gas would result in the release of entrained CO₂ that originated from the capture site.

³⁰ USEPA Subpart RR-Geologic Sequestration of Carbon Dioxide 40 CFR § 98.445 Procedures for Estimating Missing Data

Measurement Parameter	Description	Comment
Concentration of CO ₂ in gas stream	Position 1-7. Perform gas analysis through laboratory analysis or on-line gas chromatograph or other gas analyzer.	Measurements should be taken at a minimum frequency of once per month. Gas analyzers should be calibrated at least once per quarter or in accordance with manufacturer's specifications. See Section 7.0 QA/QC procedures. If data are missing, follow procedures for estimating missing data contained in USEPA Subpart RR regulations

5.4 Monitoring, Reporting, and Verification (MRV) Plan

The general framework of a MRV plan for geologic sequestration will include the following components:

- (1) Delineation of the area of review.
- (2) Identification of potential leakage pathways for CO₂ in the monitoring area and the likelihood, magnitude, and timing, of CO₂ reaching the atmosphere through these pathways.
- (3) A strategy for detecting and quantifying any surface leakage of CO₂.
- (4) A strategy for establishing the expected baseline level of CO₂ at the various monitoring sites.
- (5) A summary of the considerations used to calculate site specific variables for the mass balance equation.
- (6) A plan for monitoring the parameters included in Table 5-5.

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. Their Model Rules and Regulations for CCS projects focus primarily on subsurface monitoring of the geologic storage reservoir and overlying formations through the use of observation wells. The Task Force believes that early leak detection in the subsurface of any CO₂ would be the best mechanism to protect public health and safety and the environment and offer sufficient time to address the cause of that leakage. As an example, early detection in the subsurface would allow for the drilling of wells to remediate leakage by producing or capturing leaked CO₂ and re-injecting that CO₂ back into storage. Rather than being overly prescriptive, the Task Force has recommended that the Model Rules and Regulations require the operator to submit a comprehensive monitoring plan that is tailored to the specific characteristics of the site.

To ensure permanence of CO₂ in the subsurface, a MRV framework for EOR projects shall include the following components:

- A static geologic model of the injection reservoir
- Flow simulations of CO₂ injection conducted to a point in time when the CO₂ plume ceases to migrate after injection is stopped to determine the ultimate extent of the CO₂ plume
- Based on flow simulations results, delineate a two-dimensional "reservoir boundary" that encompasses the areal extent of the CO₂ plume plus some buffer
- Identify leakage pathways within this reservoir boundary (usually well bores, faults and fractures)
- Remediation of potential leakage pathways, as needed
- A monitoring strategy to monitor the areal extent of the CO₂ plume to ensure it remains confined within the reservoir boundary.

In the case of EOR operations, these components should be included in a MRV plan with a combination of detailed site characterization, baseline monitoring, operational monitoring, and post-injection monitoring tasks. Since these sites have a prior history of oil production, many of these elements may have been completed or can be undertaken to determine the site's suitability for CO₂ injection, retention, and sweep efficiency, and to meet current regulatory requirements. All CO₂ injection wells used for EOR operations in the US meet Class II well requirements outlined by the USEPA underground injection control (UIC) program.³¹ A MRV plan for EOR operations is described here.

5.4.1 Site Characterization

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, data on how the well was completed (and plugged/ abandoned if appropriate) including any cement bond logs available. Assurance as to the adequacy of the plugging of abandoned wells is essential.

If the drilling history in and around the reservoir cannot be documented with a high degree of confidence then the potential presence of any unknown abandoned wells, if suspected to exist, within and surrounding the reservoir will be systematically investigated. This search could use airborne magnetic surveys and/or other suitable approaches. Well records will be researched and physical inspection conducted as necessary to determine the condition of wells that are discovered. A corrective action plan should be developed for those wells that are considered to be high 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 leakage at the well. The ability to convert one or more of these wells to monitoring wells for the project should also be investigated.

³¹ USEPA, 40CFR Part 146, Underground Injection Control Program: Criteria and Standards

Reservoir characterization is the key step that forms the basis for any monitoring plan and will be the bulk of activities during site characterization. Working with the EOR operator, required data (existing and newly collected) can be compiled to develop a fluid flow model that is calibrated with production history and used to predict CO₂ distribution during the EOR project and after project end. Where available, 3-D seismic data can be used to characterize the geology of the reservoir and create a “static reservoir model”. Well logs can be used to estimate the porosity and permeability distributions within the reservoir. It is particularly important to identify “flow units” that will dominate the flow of fluids during and after injection. Reservoir characterization should include a review of the completion records and produced fluids on a well-by-well basis as available. The reservoir model created by this activity can form the input for reservoir simulation.

Compositional reservoir simulations are becoming best practice activities for initiating CO₂-EOR floods. Such simulations play multiple roles including prediction of possible out of pattern migration of CO₂ and forming the basis for quantitative history match for fluid inputs and outputs for the field after injection has begun. To calibrate this model it is important to compile the prior history of: oil, gas and water production; and injection of all fluids over time. Assuming the EOR project has not been initiated, the calibrated model is ready to simulate the injection of the expected CO₂ volumes. In order to update and compare the model results, material balances for total field CO₂ injection resulting from purchased CO₂ and CO₂ being recovered from oil production and being re-injected into the reservoir, as well as any water injected, should be maintained on a monthly basis. The observed material balances for fluids (oil, gas, water, CO₂) will be compared to the fluid production predicted by the reservoir modeling. To accurately understand the material balance the hydrocarbon content of the recycled CO₂ stream should be measured. Prior to CO₂ injection, a detailed review should be conducted of the site characterization reports and modeling and simulation studies, which are usually already performed by the EOR operator to support optimal production, permit applications, etc.

5.4.2 Baseline Monitoring

The aim of this activity is to establish baseline levels, prior to initiation of CO₂ injection, for all parameters that will be monitored during the operational phase. Baseline measurements should be done for a period of time that allows for the collection of data that are representative of site conditions prior to the initiation of injection. A baseline will be developed consisting of pressures, geochemical properties and characteristics of reservoir fluids outside the confining zones, and groundwater. Similar tests shall be conducted periodically (see Table 5-4) during the injection phase to monitor CO₂ plume movement and/or the possibility of leakage.

5.4.3 Operational Monitoring

During operation, fluid geochemical sampling and analysis should be performed at all monitoring well locations and compared to baseline measurements to detect any migration of CO₂ and leakage through the seal. The sampling results should be compared to computer simulation studies on the expected movement of CO₂ in the oil reservoir derived from reservoir and operational data. Modeling parameters should be updated if necessary based on monitoring results. Geochemical fluids sampling should be conducted semi-annually or more frequently depending on the results of the baseline measurements. Over time, this frequency will be adjusted based on measurement and modeling results.

It is important to document that all the produced CO₂ is being recycled, that there is no out-of-zone or off-lease migration if the out of zone or off lease migration poses a risk that CO₂ will leak to the atmosphere or into groundwater. If the CO₂ EOR project is in the middle of a producing field under water flood, regular sampling of producers both in the patterns under flood and adjacent patterns can constrain the evolution of the plume. The exact method shall be worked out to mesh smoothly with the normal operation. If the injection is at the edge of the lease, it is important to consider the possibility of off-lease migration if the off-lease migration would result in CO₂ leaking to the atmosphere.

Mechanical integrity testing (MIT) should be performed in accordance with current regulatory requirements. This includes internal and external MITs and pressure fall off tests. Pressure in the injection tubing string and annulus should be measured continuously, and in regions outside the confining zone (e.g. USDWs) at periodic intervals (expected to be semi-annually). These measurements will determine if any pressure anomalies have occurred that may infer CO₂ leakage out of the injection zone.

5.4.4 Post-injection Monitoring

Following completion of CO₂ injection and associated hydrocarbon recovery operations, a certain level of monitoring will be maintained during the post-injection phase until the end of the project term to assure permanence. Although specific monitoring tools will be determined based on the site-specific experience gained during the baseline and operational phases of the project, the monitoring program should include methods to track the CO₂ plume and the pressure front and continued monitoring above the confining zone. 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 CO₂ within the reservoir should stabilize. Therefore minimal lateral movement is expected and tracking of the lateral extent of the CO₂ plume through appropriate measurements and modeling will be adequate. CO₂ plume tracking combined with measurements of certain subsurface parameters made above the confining zone (e.g., pressure and/or water chemistry as appropriate) will monitor any potential leakage that may be caused by vertical movement of CO₂ within the reservoir. Due to buoyancy effects, the CO₂ plume will tend to migrate to the upper regions of the reservoir 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.

Table 5-4 Monitoring for CO₂--EOR Sequestration

Technology	Utilization
Baseline Monitoring	
Geochemical Sampling	Sampling of aquifers and USDW zones above the reservoir shall be done at least monthly for an appropriate period prior to CO ₂ injection. Sensitivity analysis to determine which constituents will be sampled, sampling method, and frequency of samples will be conducted.
Mechanical Integrity Testing	MITs will be done by the operator in compliance with regulations prior to initial injection of CO ₂
Pressure Monitoring	Pressure histories above the confining system to be monitored if there is an appropriate extensive unit with porosity, permeability and thickness characteristics that modeling suggests that pressure monitoring will be effective. Adequate pre-injection baseline data is important to look for trends resulting from production and water disposal pre-injection.
Pressure Testing	Testing as required per regulations prior to initial injection.
Operational Monitoring	
Geochemical Sampling	Sampling of nearest aquifers and USDW zones to be done semi-annually and more frequently if required by future regulations. Need to determine sensitive parameters that may signal leakage. If there are none, no sampling needed.
Mechanical Integrity Testing	MITs will be done by the operator once every 5 years per regulations. This frequency of testing may be increased if required by future regulations.
Pressure Monitoring	Pressure on the injection tubing string and on the annulus of the well to be measured continuously.
Injection Rate	Injection rates to be measured continuously and reported monthly.
Pressure Testing	Testing is required prior to initial injection and once every 5 years thereafter per regulations. The frequency will conform to any change in regulations.
Material Balance	Material balances to be performed on an annual basis on each injection pattern, comparing total injected CO ₂ and CO ₂ recovered from oil production and compared to reservoir models for the injection pattern under review.
Post-injection Monitoring	
CO ₂ plume front and pressure front tracking	CO ₂ plume front to be tracked using a combination of measurements and predictive modeling.
Pressure and/or Water Chemistry Monitoring	Pressure histories and/or water chemistry above the confining system to be monitored if there is an appropriate extensive unit with porosity, permeability and thickness characteristics that modeling suggests that these measurements will be effective.

5.5 Measurement Techniques

Volumetric flow rates will be measured 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. Flowmeters include, but are not limited to, rotameters, turbine meters, coriolis meters, orifice meters, ultra-sonic flowmeters, and vortex flowmeters. The devices should be installed and calibrated in accordance with manufacturer's specifications. The flowmeter 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. 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). Flowmeter calibrations performed should be National Institute of Standards and Technology (NIST) traceable.

Gas or liquid composition analysis should 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 CO₂ concentration in the gas stream is 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^{32 33 34}

³² Best Practices for: Monitoring, Verification, and Accounting of CO₂ Stored in Deep Geologic Formations, USDOE, 2009 www.netl.doe.gov/technologies/carbon_seq/refshelf/MVA_Document.pdf

³³ 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) www.epa.gov/climatechange/emissions/downloads10/Subpart-RR-UU_TSD.pdf

5.6 Data and Analysis for Verification

This section provides information about specific parameters that should be monitored to calculate GHG savings from a CCS project according to the quantification procedures in Section 4.0. Project developers shall incorporate this information into their respective monitoring plans 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 5-5 aggregates the specific monitoring parameters and activities needed for a comprehensive assessment of the GHG reductions that might be claimed by a project developer. Project developers should take into account the location, type of equipment and frequency of measurement for each variable.

In addition to the parameters in Table 5-5, project developers shall report the results of the MRV measurements discussed in Section 5-4.

³⁴ Fluid Injection in Productive Reservoirs, Texas Administrative Code (TAC), Title 16, Part 1, RULE §3.46

Table 5-5 Monitoring Parameters

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	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	[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.
%CO₂	% CO ₂ 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 should be calibrated in accordance with manufacturer's specifications.
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 should be measured to account for the total output from the primary process that would have occurred in the absence of the project. Measurement devices should be calibrated in accordance with manufacturer's specifications.
Non-Captured CO₂ Emissions from the Primary Process					

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
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 should be calibrated quarterly or according to manufacturer specifications if more frequent calibrations are recommended by the manufacturer.
%CO₂	% 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 should be calibrated in accordance with manufacturer's specifications.

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
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	<p>For gaseous fuels, daily measurement of the gas flow rate.</p> <p>Flow meters used to measure the volume of gas should be calibrated according to manufacturer specifications.</p> <p>For liquid and solid fuels monthly reconciliation of purchasing records and inventory adjustments as needed.</p> <p>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</p>
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	<p>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.</p>

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
Stationary Combustion Emissions for CO₂, CH₄, and N₂O					
Fuel i	Volume of each type of fuel, by fuel type i, used to 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	<p>For gaseous fuels, daily measurement of the gas flow rate.</p> <p>Flow meters used to measure the volume of gas should be calibrated according to manufacturer specifications.</p> <p>For liquid and solid fuels monthly reconciliation of purchasing records and inventory adjustments as needed.</p> <p>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.</p>

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
Indirect CO₂ 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	<p>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 should be calibrated by an accredited party per manufacturer's specifications</p> <p>Electricity consumption should 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 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.</p> <p>Electricity usage can also be determined from monthly bills received from the utility</p>
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.

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
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 cogen operator showing the quantity and condition of steam can be used to determine steam usage. Steam meters, or similar, should 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 cogen operator can be used to determine electricity usage. Electricity meters should 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, should 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 should be calibrated by an accredited party per manufacturer's specifications. Cogen operator's monthly records can be used as source of data.

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
Vented and Fugitive CO₂ Emissions from CO₂ 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 should be calibrated quarterly or according to manufacturer specifications if more frequent calibrations are recommended by the manufacturer.
%CO₂	% 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 should be calibrated in accordance with manufacturer's specifications.
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 should be calibrated quarterly or according to manufacturer specifications if more frequent calibrations are recommended by the manufacturer.
Vented and Fugitive CO₂ Emissions from CO₂ Storage					

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
$N_{\text{Blowdown } i}$	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 should keep detailed logs of all venting incidents.
$V_{\text{Blowdown } i}$	Total volume of blowdown equipment chambers for equipment (including pipelines, manifolds and vessels between isolation valves).	m ³ , scf	[o], [c]	NA	Volume can be estimated based on equipment specifications (pipeline diameters etc.), flow meters, duration of event.
%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 should 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 with the CO ₂ pipeline and the injection wells in the formation.	#	[o]	NA	Storage site operator should 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 the 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.

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
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 , scf	[m]	Daily	Continuous metering of sales volumes of natural gas.
% CO₂ 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.
Mass Oil Prod	Mass of crude oil and other hydrocarbons produced from the formation that CO ₂ is being injected into	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 hydrocarbons produced from the formation.	-	[m]	Annual	Conduct lab analysis of composition of crude oil

Parameter	Description	Units	Calculated [c], Measured [m], Operating records [o]	Measurement frequency	Comment
CO₂ Transferred Offsite					
Vol CO ₂ _Transfer	Volume of produced CO ₂ from an enhanced oil or gas operation transferred outside project boundary in each year.	m ³ , scf	[m]	Monthly	CCS projects developers 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.
Fugitive CO₂ from Storage to Atmosphere					
CO _{2z}	Total mass of CO ₂ emitted through leakage pathway z to atmosphere in year y.	Metric tons	[c]	NA	In the event that 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. <u>Note:</u> Examples of leakage pathways are faults and fractures, not fugitive CO ₂ from wells (as calculated according to Equation 4.23).

6.0 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 Title

Since CCS projects involve capture, transport, and sequestration processes, which are often conducted by different companies, the ownership to the title of CO₂ 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. Alternatively, through contract, title to the credits can be transferred to an outside third party, who will be the responsible party to the registry. Owners of CO₂ credits shall provide assurances that they have the legal right to fulfill project commitments.

During the operational phase, documentation that traces the chain of custody of CO₂ as it is transferred from parties involved in the capture, transport, and sequestration processes shall be established.

6.3 Permanence and Liability

For CCS projects, project proponents demonstrate a level of assurance that the CO₂ captured and stored is permanently sequestered underground. The project's MRV plan that includes proper site selection, characterization, baseline, operating, and post-injection monitoring tasks along with the proper QA/QC features provides this level of assurance.

The post-injection monitoring tasks (such as those described in Section 5.4.4 for EOR sites), will be conducted for the minimum project term defined in Section 2.2. Site characterization coupled with the use of site-specific monitoring and modeling conducted during the baseline and

operational phases of the project provide data and information for the operator to calibrate, validate and compare the model over the life of the project. This model will be used as a predictive tool to monitor and track the CO₂ 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). Based on the conformance of the model predictions with measurements and the absence of leakage detected within the subsurface outside the reservoir, permanence of the injected CO₂ is assured. If there are deviations to the expected results, monitoring will be continued for an additional period as described in Section 2.2.

In the unlikely event that leakage occurs during the operational and post-injection phases of the project, remediation will be conducted in accordance with the site-specific remediation plan, which includes the estimation of any CO₂ that leaks to the atmosphere.

In spite of the project's MRV, there is potential for GHG reductions and removals to be reversed upon exposure to risk factors, including unintentional reversals (e.g., seismic disturbances or other unanticipated releases of CO₂) and intentional reversals (if not re-injected for permanence). Projects should evaluate general and project-specific risk factors. General risk factors include risks such as financial failure, technical failure, management failure, regulatory and social instability, and natural disturbances. Project specific risk factors vary by project type.

An operator will have to 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. Appendix B includes a listing of laws that have been enacted and/or bills that are currently pending in the State legislatures related to liability and pore space ownership issues in CCS projects.

Long-term liabilities arise from migration of the CO₂ plume, either vertically through well bores, fractures, or faults or horizontally by moving to points of leakage. Confidence in the location of CO₂ plume in the reservoir increases over years of MRV operations. After several years of

injection operations, a well-characterized CO₂ plume and its associated hazards can be well recognized.

Trespass is a liability that can occur during operations or post-operations. It is the migration of the CO₂ plume into areas inside or outside the reservoir that initial modeling did not anticipate or was not tracked by MRV techniques. 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), which held that injection associated with a state-authorized secondary recovery project would not cause trespass. This was decided even though fluids move across property lines. In other States, this issue would be dependent on individual State regulations and statutes.

To cover liability of leakage, project proponents can purchase private insurance. Insurance premiums would be paid by the project developer to the insurance company, and, in the event of CO₂ leakage to the atmosphere, the insurance company would cover obligations to compensate for reversals in GHG emissions reductions (e.g., purchase allowances or credits). These policies could be short-term policies that are renewed periodically over the project term. If small releases occur during the project term and result in leakage to the atmosphere, then those reversals can be reconciled through accounting; by deducting an equal quantity of credits from the following year's total of qualified credits.

6.4 Pore space ownership

CCS project developers may need to own or obtain rights to the subsurface pore space where CO₂ will be injected and sequestered. In the U.S., with the exception of federal lands, the acquisition of storage rights, which are considered property rights, generally are functions of state law. In many States, no clear property right to use pore space has been assigned to surface property owners covering the injection of fluids into deep geological formations, and such injection under the underground injection control (UIC) program goes on without approval from surface land owners except for those on whose property the injection well is located. These cases appear to have adopted the “inverse rule of capture” rule that determines in effect that the subsurface rights vest in whoever is able to assert them physically on a first-come basis.

As indicated in Appendix B, while pore space ownership issues are beginning to be addressed through State law and regulation, there is no uniformity in the way in which rights to inject fluid into deep pore space are currently being handled. Some states, including Montana, Wyoming, and North Dakota have assigned pore space ownership to the surface owners. In Wyoming and Montana, that ownership may be severed and assigned to the mineral owner. In Texas, where mineral rights are severed from surface rights, there is no clear ownership of pore space between surface and mineral owners, although it is likely owned by surface owners.

In the case of CO₂ enhanced oil recovery projects, the right to inject CO₂ 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 CO₂ during the operational phase of a CO₂ EOR project would be permissible under an oil and gas lease.³⁵

Migration of any injected fluid is only permissible provided the migration is in compliance 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.³⁶

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, there is a need for the continued monitoring activities for the remainder of the project term to assure permanence. Project proponents should 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 should obtain 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 remediation activities.

³⁵ Storage of Carbon Dioxide in Geologic Structures: A Legal and Regulatory Guide for States and Provinces, IOGCC, 2007.

³⁶ Carbon Capture and Sequestration: Framing the Issues for Regulation, Interim Report, CCSReg Project, January 2009

6.5 Community and Environmental Impacts

CCS projects involve the installation of capture technologies, pipelines and gas separation and compression infrastructure. These are capital-intensive projects that 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 validation/verification body on request. 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 (by community members only, not external stakeholders) of negative environmental and community impacts.

7.0 QA/QC

QA/QC procedures should be implemented during all phases of the project to assure data quality and completeness. Consistent with the USEPA requirements in 40 CFR Part 98.3(i), all measurement devices must be calibrated according to the manufacturer's recommended procedures or an appropriate industry consensus standard to an accuracy of 5 percent. Calibration records should be maintained and made available to 3rd party verification.

For flow meters, all calibrations should be performed at measurement points that are representative of normal operation of the meter. Except for the orifice, nozzle, and venturi flow meters, (those are described in the next paragraph of this section) the calibration error at each measurement point is calculated using Equation 7-1. The terms "R" and "A" in Equation 7-1 must be expressed in consistent units of measure (e.g., gallons/minute, ft³/min). The calibration error at each measurement point shall not exceed 5.0 percent of the reference value.

$$CE = (R - A)/R \times 100 \quad (\text{Eq.7-1})$$

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 should 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 7-2. The terms "R", "A", and "FS" in Equation 7-2 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 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.

$$CE = (R - A)/FS \times 100 \quad (\text{Eq. 7-2})$$

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 3rd 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)).

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).

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

8.0 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) should be explicitly addressed and discussed by the project proponent and described in the project document 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 8-1. 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 flowmeters, 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.

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 EOR sites, the geologic storage site is well characterized and modeled. The development of a site-specific MRV 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 are currently being utilized to meet state regulations. Based on this, the uncertainty in detection and measurement of leakage is considered low for EOR sites.

Table 8-1 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	<p>Extensive industry experience with flowmeters used for this application. Flowmeters should be installed and operated in accordance with manufacturer's specifications.</p> <p>Flow meters should be calibrated quarterly or according to manufacturer specifications if more frequent calibrations are recommended by the manufacturer.</p>
%CO₂ % CO₂ Gas Sold (fuel)	Low	<p>Industrial processes producing CO₂ are well controlled so minimal variability of CO₂ concentrations in gas stream.</p> <p>Direct measurement of the composition of the gas stream should be made on a monthly basis.</p> <p>Gas analyzers should be calibrated in accordance with manufacturer's specifications.</p>
Output	Low	<p>Measurements based on the type of primary process. Output should be measured using instrumentation that should be calibrated in accordance with manufacturer's specifications.</p>
Fuel i Total Fuel Cogen	Low	<p>For gaseous fuels, daily measurement of the gas flow rate.</p> <p>Flow meters used to measure the volume of gas should be calibrated according to manufacturer specifications.</p> <p>For liquid and solid fuels monthly reconciliation of purchasing records and inventory adjustments as needed.</p> <p>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</p>
Mass Frac. Carbon i	Low	<p>Direct measurement of the carbon content of the fuel using industry accepted practices.</p>

Data Parameter	Uncertainty Level of Data	Comments
Electricity Electricity CCS Project Electricity Cogen	Low	<p>Continuous measurement of electricity consumption using meters calibrated by an accredited party per manufacturer's specifications.</p> <p>If 3rd 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.</p>
Heat CCS Project Heat Cogen	Low	<p>Daily metering of thermal energy sales/purchases to/for the CCS project using meters calibrated by an accredited party per manufacturer specifications.</p>
$N_{\text{Blowdown } i}$ $V_{\text{Blowdown } i}$	Low	<p>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.</p>
$\% \text{GHG } j$	Low	<p>Direct measurement of the composition of the gas stream on a monthly basis.</p> <p>Gas analyzers should be calibrated in accordance with manufacturer's specifications.</p>
Count_s T_s	Low	<p>Storage site operator should develop and maintain an equipment inventory of all possible fugitive 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.³⁷</p>
$\text{Mass}_{\text{Water Prod}}$ $\text{Mass}_{\text{Oil Prod}}$	Low	<p>Data on water production and injection rates, which are measured with calibrated flowmeters are routinely maintained by operators. Monthly reconciliation of water disposal records are routinely conducted.</p> <p>Oil or other hydrocarbon production values are based on continuous measurements. Data can be obtained from reconciliation of oil or other hydrocarbon sales from facilities associated with the producing formation.</p>

³⁷ US Environmental Protection Agency. Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems, Final Rule: Subpart W. November 30, 2010

Data Parameter	Uncertainty Level of Data	Comments
Mass Frac CO ₂ in Water Mass Frac CO ₂ in Oil	Low	Data obtained from periodic lab analysis of produced water and produced oil samples using industry accepted practices.
CO _{2z}	Low	<p>CO₂ 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.</p> <p>For oil and gas producing reservoirs that have been extensively characterized and modeled the uncertainty in detection and estimating leakage is low.</p>

A.0 APPENDIX A- SUPPLEMENTAL QUANTIFICATION METHODS

This appendix provides information on supplemental quantification methods that may be applied to perform CO₂ 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 CO₂ injection, storage facilities and at hydrocarbon production facilities is also provided.

Additional Guidance on Performing CO₂ mass balances using volume or mass flow measurements

The mass balance equations presented in this methodology rely on continuous measurement of CO₂ 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 CO₂ must be calculated in metric tons by multiplying the metered mass flow by the concentration in the flow, according to the following equations.

Equation A-1

$$CO_{2T,x} = \sum_{p=1}^4 (Q_{x,p}) * C_{CO_2,p,x}$$

Where:

CO_{2T,x} = Net annual mass of CO₂ measured by flow meter x (metric tons).

Q_{x,p} = Quarterly mass flow through meter x in quarter p (metric tons).

C_{CO₂,p,x} = Quarterly CO₂ concentration measurement in flow for flow meter x in quarter p (wt. percent CO₂, expressed as a decimal fraction).

p = quarter of the year.

x = flow meter

For a volumetric flow meter, the total mass of CO₂ is calculated in metric tons by multiplying the metered volumetric flow at standard conditions by the CO₂ 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 A-2

$$CO_{2T,x} = \sum_{p=1}^4 (Q_{x,p}) * D * C_{CO_2,p,x}$$

Where:

CO_{2T,x} = Net annual mass of CO₂ 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 CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682.

C_{CO₂,p,x} = Quarterly CO₂ concentration measurement in flow for flow meter x in quarter p (vol. percent CO₂, expressed as a decimal fraction).

p = quarter of the year.

x = flow meter.

When CO₂ is measured using more than one meter within the same component of the CCS project (e.g., multiple CO₂ injection wells), it may be necessary to sum the meter readings to calculate an aggregate mass of CO₂, as shown in the following equation.

Equation A-3

$$CO_2 = \sum_{x=1}^X CO_{2T,x}$$

Where:

CO_2 = Total mass of CO_2 measured by all flow meters in year y (metric tons).

$CO_{2T,x}$ = Total mass of CO_2 measured by flow meter x, as calculated in Equation A-1 or Equation A-2 in year y (metric tons).

X = Total number of flow meters.

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 A-4

$$PE_{Elec,y} = \sum (\text{Electrical Rating}_i \times \text{Hours}_i \times \text{Load}_i) \times EF_{Electricity}$$

Where,

$PE_{S-P-Elec,y}$ = Project emissions from electricity used to operate equipment at the CO_2 storage site in year y (tCO_{2e}/yr).

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) PCA, eGRID subregion, or State (tCO_{2e}/MWh).-See Section 4.2.1 for estimation procedures

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 CO₂ produced at the primary process is not possible.

Equation A-5

$$\text{CO}_2 \text{ Produced}_{\text{PP}, y} = \sum(\text{Fuel}_i \times \text{Mass Frac}_{\text{Carbon}, i} \times 44/12)$$

Where,

CO₂ Produced_{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).
44/12	=	Conversion factor to convert from mass of carbon to mass of carbon dioxide using molecular weights (unitless).

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 CO₂ that originate from the capture site).

Equation A-6

$$\text{PE}_{\text{Flaring}, y} = \sum(\text{Gas Flared}_i * \sum(\text{C}_i * \text{y}_i) * 44.01/23.64) + \sum(\text{Flare Fuel}_i * \text{EF}_{\text{CO}_2 \text{ Flare Fuel } i}) + \sum[\text{Gas Flared}_i * (1-\text{DE}) * \% \text{CH}_4 * \rho_{\text{CH}_4} * \text{CH}_4\text{-GWP} + \sum(\text{Flare Fuel}_i * \% \text{CH}_4 * \rho_{\text{CH}_4} * (1 - \text{DE})) * \text{CH}_4\text{-GWP} + \sum(\text{Vol.}_{\text{Gas Flared}} * \text{EF}_{\text{N}_2\text{O}_{\text{Gas Flared } i}}) + (\text{Flare Fuel}_i * \text{EF}_{\text{N}_2\text{O}_{\text{Flare Fuel } i}})] * \text{N}_2\text{O-GWP}$$

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>i</i> , used to ensure complete combustion of gases from the producing formation in year <i>y</i> (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 ₂ H 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).
%CH₄	=	Concentration of CH ₄ in the gas stream that is being flared in year <i>y</i> (volume percent CO ₂ or CH ₄ , expressed as a decimal fraction).
ρ CH₄	=	Density of CO ₂ at standard conditions = 0.00190 metric ton/ m ³ .
EF N₂O_{Gas Flared i}	=	N ₂ O emission factor for flaring of gas stream originating from the producing formation (e.g., tN ₂ O/m ³).
EF CO₂ Flare Fuel_i	=	CO ₂ emission factor for combustion of each supplemental fuel, by fuel type <i>i</i> , used to ensure complete combustion of gases from the producing formation (e.g., tCO ₂ /m ³).
EF N₂O Flare Fuel_i	=	N ₂ O emission factor for combustion of each supplemental fuel, by fuel type <i>i</i> , used to ensure complete combustion of gases from the producing formation (e.g., tN ₂ O/m ³).
CH₄-GWP	=	Global Warming Potential of methane = 21.
N₂O-GWP	=	Global Warming Potential of N ₂ O = 310

Additional Guidance on Selecting Emission Factors to Quantify Fugitive Emissions

The following table provides a summary of potential fugitive and venting emission sources and relevant US EPA emission factors that may be applicable to CO₂ injection and storage facilities as well as to hydrocarbon production facilities at the storage site in the producing formation.

Table A-1 Surface Components as Potential Emissions Sources at Injection Facilities³⁸

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

³⁸ US Environmental Protection Agency. Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems, Final Rule: Subpart W. November 30, 2010.

B.0 APPENDIX B: STATE LEGISLATIVE ACTIONS

SOUTHERN STATES ENERGY BOARD *Carbon Capture and Sequestration Legislation In the United States of America*

Introduction

At the time of publication, there were 23 states with Carbon Capture and Storage (CCS) related legislation, which are: AZ, MI, NY, PA, CA, IL, KY, MN, OK, VA, CO, FL, IN, KS, LA, MS, MT, ND, NM, TX, WA, WV and WY.

Four states had CCS Bills Pending as of 2011, which are: AZ, MI, NY and PA.

While coal power is associated mainly with the Midwest and Appalachian regions, the states with CCS legislation represent a comprehensive cross section of the country. States differ on their approach to enforcing these bills. Some states, such as Texas, are pushing full steam ahead, yet others, like Montana, awaited an EPA final rule. Some tackle the statute first and regulations second (Wyoming, North Dakota), while others are working to create legislative recommendations (Utah, Illinois, West Virginia). Kansas, among others, has concluded that existing legislative authority is sufficient and is able to move directly to promulgation of final regulations.

This study on state CCS legislation does not include every element addressed by these bills. Instead, it is intended to give an overview of four key areas identified as necessary elements of a broader comprehensive regulatory framework governing CCS activities. The key areas are Project Authority, Pore Space and Carbon Dioxide (CO₂) Ownership, Liability and Financing Sources.

Project Authority: This area addresses which state regulatory agency (SRA) will be charged with developing and administering rules and regulations governing CCS projects. The agency must have the authority to require compulsory joining of all participating interests in the underground storage reservoir and have appropriate permitting authority to require and operator to submit any data necessary to evaluate a proposed CO₂ storage project. Examples of such SRAs are state oil and gas regulatory agencies, state environmental agencies or state public utility commissions.

Pore Space and CO₂ Ownership: This area addresses who has the property rights to inject CO₂ into wells and who owns the CO₂ in case of unintended trespass. The right to use reservoirs and associated pore space is considered a private property right in the United States and must be acquired from the owner of those rights. To determine this, states are most likely to follow their traditional common law approach in determining these rights and, in most cases, pore space is deemed to be owned by the surface estate. CO₂, on the other hand, is treated like any other commodity and, in general, is owned by the injector.

Liability: This area addresses what party is liable for the injected CO₂ both during the injection, the closure and the long-term, post closure phase. What party is liable depends, therefore, on the phase of the project. The injection phase is the period of time during active injection. The closure period is the time when the plugging of the well is completed and continues until a future date is reached, usually 10 years after injection activities and the wells are plugged. During these phases, the operator is the liable party. The post closure phase is the period of time beginning when the project is deemed complete, usually marked by the issuance of a Certificate of Completion, and extends for the life of the well. During this phase, liability transfer to the state for monitoring, verification and remediation activities. The injector is then usually released from all liability.

Financing Sources: This area addresses both the costs of the CO₂ injection projects themselves and the long-term costs. For the costs associated with the injection project, many states will give tax incentives in the form of sales tax, income tax or property tax exemptions for qualifying endeavors. Many states have established some type of CCS trust fund to pay for the expense of long-term monitoring, verification and remediation. These trusts tend to be state administered and industry funded on a cost per ton basis.

State	Bill (year)	Project Authority	Pore Space/CO ₂ Ownership	Liability	Financing Source
AZ	SCR 1033 (2011) Pending	Arizona Department of Environmental Quality (ADEQ)			ADEQ is urged to allow the use of commercially available technologies that are designed to be as efficient as is economically practicable, including advanced super-critical pulverized coal, ultra super-critical pulverized coal, and that are designed to be carbon capture and sequestration-compatible, as potential best available control technology.
CA	SB 669 (2011) Pending	State Energy Resources Conservation and Development Commission			Provides for the full recovery in rates of long-term commitments entered into through a contract approved by the commission for electricity generated by zero- or low-carbon generating resources demonstrating new technology, if the commission determines that the commitment would benefit the state's ratepayers, economy, and the environment.
CA	A 1504 (2010) Enacted	Board of Forestry and Fire Protection			Permits fees collected under the Global Warming Solutions Act of 2006 to be used for related studies and analyses.
CO	HJR 1028 (2010) Enacted	U.S. Congress			Urges the United States Congress to pass comprehensive legislation that promotes clean energy jobs and addresses the effects of climate change including CCS technology.
CO	HB 06-1281 (2006) Enacted				Creates a CCS program and provides incentives for IGCC plants.
FL	HB 549 (2007) Enacted Ch. No. 2007-117				Provides incentives for IGCC plants.
IL	SB 1567 (2011) Pending	Carbon Capture and Sequestration Legislation Commission	To be determined by the Commission.	To be determined by the Commission.	
IL	SB 1821 (2011) Enrolled	Illinois Commerce Commission	Pipeline owners	Pipeline owners	Funding is provided by CO ₂ pipeline owners.
IL	SB 678 (2010) Enacted P.A. 96-1491	FutureGen Alliance	Title transfers once injected.	FutureGen has limited liability which only arises out of or resulting from the storage, escape, release, or migration of the post-injection sequestered CO ₂ .	State aided in securing \$1billion for FutureGen.
IL	SB 3686 (2010) Sine Die	Illinois Power Agency	"Initial Clean Coal Facility" or the Illinois Power Agency if requested.	Utility and alternative electric suppliers will have limited liability while in commercial operation.	Requires offsetting of excess emissions.
IL	P.A. 92-0012 (2002) P.A. 93-0167 (2004) P.A. 94-65 (2005) P.A. 94-1030 (2006) P.A. 95-18 (2007)				Incentives for IGCC plants.
IL	SB 1987 (2008) Enacted P. A. 95-1027				Illinois power agency may fund or operate sequestration facility.
IL	SB 1592 (2007) Enacted P. A. 95-0481				Incentives for advanced coal plants in locations where geology is suitable for sequestration.
IL	SB 1704 (2007) Enacted P. A. 95-0018		Illinois to take title to injected carbon dioxide from the FutureGen project.	State assumes any liabilities associated with the sequestered gas both during operation and for long-term liability, as well as any current or future environmental benefits, marketing claims, tradable credits, emissions allocations or offsets.	Exempts the FutureGen project from Illinois tax on electrical generating units.

State	Bill (year)	Project Authority	Pore Space/CO ₂ Ownership	Liability	Financing Source
IN	P.L. 105-1989 (1989) P.L. 159-2002 (2002) P.L. 174-2005 (2005) P.L. 191-2005 (2005) P.L. 175-2007 (2007)				Incentives for clean coal technology.
KS	HB 2418 (2010) Enacted Ch. No. 2010-63	State Corporation Commission		Exempts the Commission and the state from assuming liability for the underground storage of carbon dioxide or the maintenance of any carbon dioxide injection well or underground storage of carbon dioxide except as permitted by the Kansas tort claims act.	Fees may be collected by the commission and put into the "carbon dioxide injection well and underground storage fund."
KS	HB 2419 (2007) Enacted	State Corporation Commission			Property and income tax incentives for CCS.
KS	SB 303 (2006) Enacted				Incentives for IGCC, such as tax credits and an amortization deduction in an amount equal to 55% of the amortizable costs of such new qualifying pipeline for the first taxable year in which such new qualifying pipeline is in production, and 5% of the amortizable costs of such new qualifying pipeline for each of the next nine taxable years.
KY	SB 50 (2011) Enacted KRS 154.27	Pipeline Company	Grants companies constructing carbon dioxide transmission pipelines eminent domain powers.		
KY	HB 259 (2011) Enacted KRS 353.1-7	Energy and Environment Cabinet		Liability for stored carbon dioxide will pass to the federal or state government.	
KY	HB 1 (2007) Pending				Tax incentives for advanced coal plants.
LA	HB 495 (2010) Enacted Act 193, R.S. 9:1103		Monetary compensation is provided to the owner unless given by a contract or related to Coastal Protection and Restoration Authority.		
LA	HB 733 (2010) Enacted Act 527, R.S. 3:1221	Office of Soil and Water Conservation			Office is to participate in CCS programs.
LA	HB 661 (2009) Enacted Act 517	Office of Conservation	CO ₂ ownership matter of private contract.	Operator is liable during operation; state assumes ownership 10 years after injection is complete; operators and others with interest are released from future liability.	
LA	HB 1117 (2008) Enacted Act 315	State Mineral Board	CO ₂ owned by operator.		
LA	HB 1220 (2008) Enacted Act 315			State Mineral Board may operate and assume responsibility for facilities.	
MI	HB 4399 (2011) Pending	Department of Environmental Quality	Owner(s) having a property interest.		Fees will be put into the "Mineral Well Regulatory Fund."
MI	HB 4401 (2011) Pending	Department of Environmental Quality	Owner(s) having a property interest.	Project owner is immune from civil liability.	CCS project funded by the Owner and must be approved by the Department.

State	Bill (year)	Project Authority	Pore Space/CO ₂ Ownership	Liability	Financing Source
MI	HB 6522 (2010) Pending	State Tax Commission	CCS equipment is seen as industrial property.		
MI	HB 4016 (2009) Pending	Department of Environmental Quality			Provides a business tax credit for certain costs incurred during carbon dioxide sequestration and capture.
MI	Draft Bill	Department of Environmental Quality	Pore space owned by surface owner.	Operator is liable during operation; state assumes liability upon issuance of Certificate of Completion.	Carbon Dioxide Storage Facility Trust Fund
MI	SB 775 (2009) Pending	Department of Environmental Quality	CO ₂ ownership begins with operator and transfers to state 10 years after Notice of Completion.	Operator is liable during operation; state assumes liability 10 years after Notice of Completion.	Carbon Dioxide Storage Facility Trust Fund
MN	HB 1669 (2011) Pending	The State of Minnesota			The state is reserving credits for CCS in current or future state lands.
MN	SF 145 (2007) Enacted Ch. 136				Incentives for IGCC.
MS	SB 2723 (2011) Enacted 53-11-1	State Oil and Gas Board	At least a majority interest in the property rights is required. Sequestration wells, buildings and equipment utilized in geologic sequestration are owned by the storage operator, which includes pipelines. The owner of the carbon dioxide shall have no right to gas, liquid hydrocarbons, salt, or other commercial minerals.	To the Owner(s)	Carbon Dioxide Storage Fund
MS	HB 1459 (2009) Enacted 27-65-19				Income tax of 1.5% on businesses that sell CO ₂ for EOR or sequestration.
MT	SB 285 (2011) Enacted 82-11-183	Board of Oil and Gas Conservation in consultation with the Department of Environmental Quality and the Department of Natural Resources and Conservation	The geologic storage operator has title to the geologic storage reservoir and may transfer title of the reservoir and the stored carbon dioxide to the state.	If the title is not transferred to the state, then the Operator accepts liability.	
MT	SB 498 (2009) Enacted	Board of Oil and Gas Conservatory with comments from Department of Environmental Quality	Pore space owned by surface owner. CO ₂ owned by operator.	Operator is liable during operation; state assumes long term liability.	
MT	HB 3 (2007) Enacted				Tax incentives for gasification plants that sequester CO ₂ .
ND	SB 2318 (2011) Enacted	Legislative Management			Legislative Management will look to the possibility of CO ₂ storage easements.
ND	SB 2034 (2009) Enacted 57-51.1-03				Tax incentives for Enhanced Oil Recovery (EOR) with CO ₂ .
ND	SB 2095 (2009) Enacted 38-22 Repealed 38-08-24	Industrial Commission	CO ₂ owned by operator.	Operator is liable during operation; state assumes long term liability.	
ND	SB 2139 (2009) Enacted		Pore space owned by surface owner; severance prohibited.		
ND	SB 2221 (2009) Enacted 57-60-01; 57-60-02.1 Amended 57-60-03				Tax incentives for coal plants that capture CO ₂ .
NM	SB 994 (2007) Enacted Ch.229				Incentives for energy facilities to capture and sequester CO ₂ .

State	Bill (year)	Project Authority	Pore Space/CO ₂ Ownership	Liability	Financing Source
NY	A03182 (2010) Pending	Administered by the Department of Environmental Conservation (DEC)	The operator has ownership of the CO ₂ and the landowners have ownership of the pore space.	Default liability is to the Operator unless contracted to the owner.	Relates to a pilot program to enable the capture and storage of carbon dioxide and establishes the carbon capture and sequestration act. This bill would have no significant fiscal impacts on the state.
NY	A05836 (2010) Pending	NY Department of Environmental Conservation	Pore space owned by surface estate owner.	Operator is liable during operation; state assumes long term liability after 10 years.	
NY	A08802 (2010) Pending	NY Department of Environmental Conservation	Pore space owned by surface owner. CO ₂ owned by operator.		
NY	Advanced Clean Coal Power Plant Initiative (2006)				Incentive program for advanced coal plants with sequestration.
OK	SB 2024 (2010) Pending	Corporation Commission			
OK	SB 610 (2009) Enacted	Corporation Commission for fossil fuel bearing formations; Department of Environmental Quality for all others	CO ₂ owned by operator. Does not alter the incidents of ownership, or other rights, of the owners of the mineral estate or adversely affect enhanced oil or gas recovery efforts in the state. Prohibits the use of eminent domain to be used by a private operator.		The Petroleum Storage Tank Release Environmental Cleanup Indemnity Fund and Program and the Leaking Underground Storage Tank Trust Fund. State water/wastewater loans and grants, revolving fund, and other related financial aid programs including federal funding.
PA	HB 2405 (2010) Pending	Pennsylvania Public Utility Commission	CCS facility owns the CO ₂ once transferred. State will allow the lease of state lands for CO ₂ pipelines.	CCS facilities receive liability of CO ₂ , once transferred, and the coal combustion plant will become immune. Operators of CCS facilities have the same rights and subject to the same penalties as the Solid waste Management Act, but Administrative penalties cannot exceed \$50,000. Upon Closure of a CCS facility, liability is transferred to the state.	Carbon Dioxide Indemnification Fund
TX	HB 1796 (2009) Enacted Ch. 382	General Land Office and the Bureau of Economic Geology to build and operate a carbon dioxide repository on state-owned, offshore, submerged land.	CO ₂ owned by state for offshore sequestration.	School Land Board is liable during operation for offshore sequestration, but liability is not relieved from a producer of CO ₂ prior to it being stored.	Permanent School Fund, state grants
TX	SB 1387 (2009) Enacted Section 27.002	Railroad Commission has jurisdiction over the injection of CO ₂ into wells for production of oil or gas.	CO ₂ owned by operator, unless otherwise agreed.		Anthropogenic Carbon Dioxide Storage Trust Fund
TX	HB 469 (2009) Enacted Ch. 490	Comptroller			Tax incentive for energy projects that capture and sequester CO ₂
TX	HB 3732 (2007) Enacted Ch. 447	State Energy Conservation Office			Incentives for advanced energy projects, including advanced coal, such as "The advanced clean energy project grant and loan program."

State	Bill (year)	Project Authority	Pore Space/CO ₂ Ownership	Liability	Financing Source
VA	SB 247 (2010) pending	Department of Mines, Minerals and Energy	CO ₂ owned by operator, transfer to Commonwealth upon issuance of Certificate of Project Completeness.	Operator liable during operation. Transfers to Commonwealth upon issuance of Certificate of Project Completeness.	Carbon Dioxide Storage Facility Trust Fund
VA	SB 1416/HB 3068 (2007) Enacted Ch.933	State Corporation Commission (SCC)			Incentives for advanced coal plants
WA	SB 6001 (2007) Partially Vetoeed Ch. 307	Department of Ecology			
WV	HB 2860/SB 396 (2009) Enacted Ch. 97	Department of Environmental Protection	Will be determined by recommendations from the CCS working group	Civil liability exists for any loss of fish or any other aquatic life.	
WY	HB 17 (2010) Enacted Ch. 52	Water Quality Division of the Department of Environmental Quality		Requires liability insurance policies for geologic sequestration site permittees.	Wyoming geologic sequestration special revenue account, funded by monies collected from entities permitted to operate geologic sequestration sites in Wyoming. Appropriates \$200,000 to fund the reclassification of a position within DEQ to help with the rule making and financial assurance duties imposed by this legislation
WY	HB 58 (2009) Enacted Ch. 50		CO ₂ owned by operator.	Operator liable during operation. No person is liable for the consequences of injecting carbon dioxide simply because they own the pore space, have the ability to control the pore space or have given consent to the injection.	
WY	SB 1 (2008) Enacted Ch. 48				Funding for sequestration site evaluation and advancement of clean coal and carbon management activities (\$1.2 million)
WY	HB 90 (2008) Enacted Ch. 30	Department of Environmental Quality			\$250,000 given to the working group for related expenses such as permitting.
WY	HB 89 (2008) Enacted Ch. 29		Owner of the surface estate owns the pore space in all strata below the surface. Pore space owned by surface owner, may be severed.	Legal requirements for notice to real property owners are not required for pore space owners unless the law specifically identifies those owners as being required to be notified.	