

Appendix B-2

Proposed Amendments to the Carbon Capture and Sequestration Protocol Under the Low Carbon Fuel Standard

Greenhouse Gas Quantification Methodology for Carbon Capture and Sequestration under the Low Carbon Fuel Standard



**Greenhouse Gas Quantification
Methodology for Carbon Capture and
Sequestration under the Low Carbon Fuel
Standard**

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GREENHOUSE GAS QUANTIFICATION METHODOLOGY FOR CARBON CAPTURE AND SEQUESTRATION UNDER THE LOW CARBON FUEL STANDARD

Chapter 1. Applicability and Definitions

1.1. Applicability

- (a) Carbon Capture and Sequestration (CCS) projects that meet the permanence certification requirements pursuant to Section C of the Geologic Carbon Storage Protocol (GCS Protocol) and applicable CCS provisions in sections 95489 and 95490 of the Low Carbon Fuel Standard regulation (title 17, California Code of Regulations (CCR) sections 95480-95503) must use the accounting approaches specified in this Greenhouse Gas Quantification Methodology for Carbon Capture and Sequestration (LCFS CCS QM) to generate Low Carbon Fuel Standard (LCFS) credits.
- (b) This Methodology applies to CCS projects that:
 - (1) Capture CO₂ from industrial or direct air capture systems;
 - (2) Transport the captured CO₂ to a geologic carbon storage (GCS) site;
 - (3) Inject and permanently sequester CO₂ in accordance with the GCS Protocol; and
 - (4) Meet all monitoring, reporting, verification, and permanence requirements specified under the LCFS Regulation and the GCS Protocol.

1.2. Definitions and Acronyms

- (a) Definitions: For purposes of this Methodology the following definitions apply:
 - “Atmospheric CO₂ leakage” means the intended or unintended release of stored CO₂ outside the storage complex to the surface and atmosphere.
 - “Brine” is water containing dissolved minerals and inorganic salts in solution, including sodium, calcium, or bromides. Water containing dissolved solids in excess of 10 grams per liter (g/L) is classified as brine. Large quantities of brine are often produced along with oil and gas.
 - “Carbon capture and sequestration (CCS)” means the processes of capturing CO₂ present in flue or exhaust gases and direct air capture via chemical and/or physical separation methods, transporting the CO₂ to an injection site, and injecting and permanently sequestering the captured CO₂.
 - “Carbon dioxide equivalent” or “CO₂ equivalent” or “CO₂e” means the number of metric tons of CO₂ emissions with the same global warming potential as one metric ton of another greenhouse gas. For the purposes of the LCFS CCS QM, global warming potential values listed in the CA-GREET model are used to determine the CO₂ equivalent of GHG emissions.

“CCS Project” means a project that captures CO₂ by an eligible entity specified in section 95490(a) of the Low Carbon Fuel Standard Regulation, transports the captured CO₂ to an injection site, and injects and permanently sequesters the captured CO₂ pursuant to the Geologic Carbon Storage Protocol.

“CCS Project GHG emissions” means the GHG emissions from specified activities associated with a CCS Project.

“CCS Project Operator” means the entity responsible for operating and managing all or a portion of CCS Project activities, including carbon capture, compression, transport, injection, and compliance with LCFS Regulation and GCS Protocol requirements.

“CO₂-enhanced oil recovery (CO₂-EOR)” means the injection into and storage of CO₂ in oil reservoirs contributing to the extraction of crude oil.

“CO₂ injection” means the process of injecting CO₂ into geologic reservoirs.

“CO₂ leakage” means any movement of stored CO₂ out of the storage complex.

“CO₂ stream” means CO₂ that has been captured from an emission source (e.g., a power plant) or ambient air, and may contain incidental associated substances derived from the source materials and the capture process, and any substances added to the stream to enable or improve the injection process.

“CO₂ supplier” means the entity that captures the CO₂ and either provides it for injection or transport to the GCS site, or injects or transport the CO₂ to the GCS site. The CO₂ supplier may also be the CCS Project Operator.

“Depleted oil and gas reservoir” means any reservoir that does not currently produce oil or gas, and is considered to have no economically recoverable oil or gas using current technology.

“Entrained CO₂” means CO₂ that remains in water, oil, or natural gas after the (oil, water, and natural gas) separation has taken place.

“Fugitive emissions” means unintentional leakage of greenhouse gases from surface equipment such as connectors, block valves, control valves, pressure relief valves, orifice meters, and regulators.

“GCS site” “storage site,” or “site” means the storage complex, all injection, production, monitoring, and observation wells and plugged and abandoned wells that penetrate the storage complex, and any facilities or infrastructure inclusive of and downstream of the injection meter or wellhead of the injection well (whichever is further upstream from injection) and any other location that is

identified as requiring in-situ monitoring to ensure permanent storage of injected CO₂.

“Greenhouse gas emissions reductions” or “GHG emissions reductions” means the net amount of greenhouse gas emissions (MT CO₂e) reduced through CCS projects under the LCFS.

“Low Carbon Fuel Standard Regulation” or “LCFS Regulation” or “LCFS” means title 17, California Code of Regulations (CCR) sections 95480-95503.

“Permanent Storage” or “Permanence” means sequestered CO₂ will remain within the storage complex for at least 100 years post-injection completion, as demonstrated by permanence certification under the GCS Protocol.

“Recycled CO₂” means CO₂ that is separated from oil, water, and natural gases, and reinjected back into the reservoir.

“Storage complex” means the three-dimensional subsurface volume comprised of a storage zone used for the injection and permanent storage of CO₂, the primary confining layer, and may include other formations that dissipate pressure or impede CO₂ plume migration vertically or laterally. Definitions, characteristics, and the required testing and monitoring plan requirements for each type of storage complex are described in the GCS Protocol.

“Subsurface CO₂ leakage” means the vertical movement of stored CO₂ out of the storage complex that does not reach the atmosphere.

“Vented emissions” means intentional or designed releases of CH₄ or CO₂ including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

For any term not defined in subchapter 1.2(a) of this Methodology, the definitions in section 95481 of the LCFS Regulation, and the definitions in sections 39010 through 39060 of the Health and Safety Code, except when included in the LCFS Regulation, shall apply.

(b) Acronyms:

“CA-GREET” means the California - Greenhouse gases, Regulated Emissions, and Energy use in Transportation Model (version specified in the LCFS Regulation).

“CCS” means Carbon Capture and Sequestration.

“CH₄” means methane.

“CO” means carbon monoxide.

“CO₂” means carbon dioxide.

“CO_{2e}” means CO₂ equivalent.

“CO₂-EOR” means CO₂-enhanced oil recovery.

“GCS” means geologic carbon storage.

“GHG” means greenhouse gas.

“LCFS” means the Low Carbon Fuel Standard (title 17, California Code of Regulations (CCR), sections 95480-95503.)

“MRR” means the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (title 17, California Code of Regulations, sections 95100 et seq.)

“MT” means metric ton.

“N₂O” means nitrous oxide.

“SSR” means sources, sinks, and reservoirs.

“VOC” means volatile organic compound.

Chapter 2. GHG Quantification Requirements for CCS Projects

This Methodology establishes the requirements for quantifying GHG emissions, GHG emissions reductions, and net CO₂ sequestration associated with CCS projects seeking LCFS crediting. CCS Project Operators must comply with the GHG quantification requirements pursuant to Chapters 2 and 3 in calculating GHG reductions to quantify emissions and emission reductions consistent with this Methodology, the LCFS Regulation, and all applicable requirements in the GCS Protocol.

2.1. GHG Quantification Requirements

- (a) All GHG emissions sources, sinks, and reservoirs (SSRs) that fall within the CCS project boundary must be identified and quantified. CCS Project Operators must use metered data where required, apply the equations in this Methodology, and maintain documentation demonstrating the accuracy, completeness, and reproducibility of all calculations.
- (b) For each reporting period, CCS Project Operators must quantify:
 - (1) Gross captured CO₂;
 - (2) CO₂ delivered for injection;
 - (3) CO₂ injected;
 - (4) CO₂ permanently stored, consistent with the GCS Protocol;
 - (5) Direct and indirect GHG emissions associated with capture, conditioning, transport, injection, monitoring, and verification;
 - (6) Any subsurface or atmospheric leakage; and
 - (7) Net GHG reductions for LCFS crediting.
- (c) GHG quantification must reflect the actual operating conditions at the capture facility, during transportation, and at the GCS site, and must be consistent with LCFS fuel pathway and project-based reporting requirements. Greenhouse gas emission factors and global warming potentials CA-GREET must be used. All references to CA-GREET in this Methodology refer to the version specified by the LCFS Regulation.
- (d) All parameters required by this Methodology must be monitored, verified, and available for audit pursuant to the LCFS Regulation and the GCS Protocol.

2.2. Project Boundary

- (a) The quantification requirements for CCS are delineated by a project boundary that covers all SSRs from a CCS project. All SSRs within the project boundary must be accounted for when quantifying GHG emissions reductions from CO₂ sequestration.
- (b) The CCS project boundary encompasses all activities required to capture, condition, transport, inject, and permanently sequester CO₂ in accordance with

the GCS Protocol. The project boundary includes both direct and indirect GHG emissions.

- (c) At a minimum, the following SSRs must be included:
 - (1) Capture System (including dehydration and compressions) SSRs:
 - (A) Energy use for CO₂ capture (steam, electricity, fuel combustion); and
 - (B) Chemical and fuel production and consumption.
 - (2) CO₂ Transport SSRs:
 - (A) Energy used for pipeline transport, if applicable;
 - (B) Energy used for trucks, rail, or ships transport, if applicable;
 - (C) Fuel production; and
 - (D) Land use change for new pipelines.
 - (3) Injection and Storage SSRs:
 - (A) Energy use for injection and sequestration;
 - (B) Fuel production;
 - (C) Venting events and fugitive emissions;
 - (D) Pressure management;
 - (E) Subsurface distribution of injected CO₂;
 - (F) Dissolution, residual trapping, and mineralization;
 - (G) Any CO₂ leakage, whether atmospheric or subsurface; and
 - (H) Land use change for new storage complexes.
- (d) Emissions associated with fuel, electricity, steam, chemicals, and other inputs must be calculated using CA-GREET emission factors. If an emission factor for a particular fuel is not available in CA-GREET or in Appendix E, applicants must apply to CARB for approval to use an emission factor from an alternative source.
- (e) The specific types of equipment and sources included within the project boundary may vary depending on the CCS project type. Figure 1 illustrates the project boundary for projects in which captured CO₂ is sequestered in oil and gas reservoirs used for CO₂-EOR, including the associated SSRs. Figure 2 illustrates the project boundary for capturing CO₂ and sequestering it in depleted oil and gas reservoirs and saline formations.
- (f) Any emissions downstream of the GCS site are excluded from the project boundary (except entrained CO₂ in the case of CO₂-EOR), as such emissions are associated with downstream products rather than CCS project operations.
- (g) CO₂ that is permanently stored in accordance with the GCS Protocol is considered sequestered. CO₂ that migrates outside the storage complex or is released to the atmosphere must be quantified as leakage.
- (h) Emission sources outside the defined CCS project boundary may not be included in LCFS crediting calculations unless explicitly allowed in this Methodology.

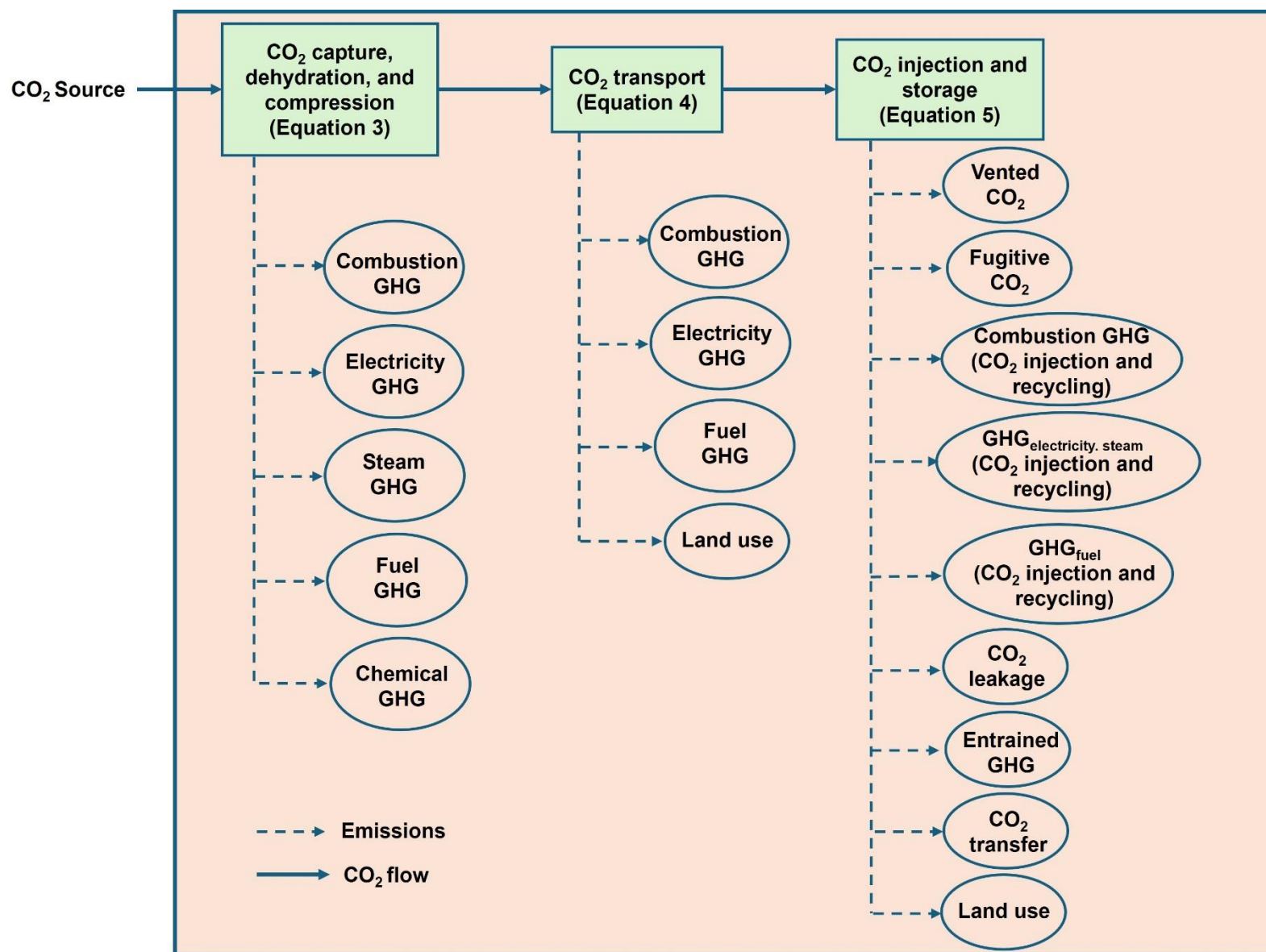


Figure 1. Project boundary for CO₂ capture and sequestration in oil and gas reservoirs used for CO₂-EOR.

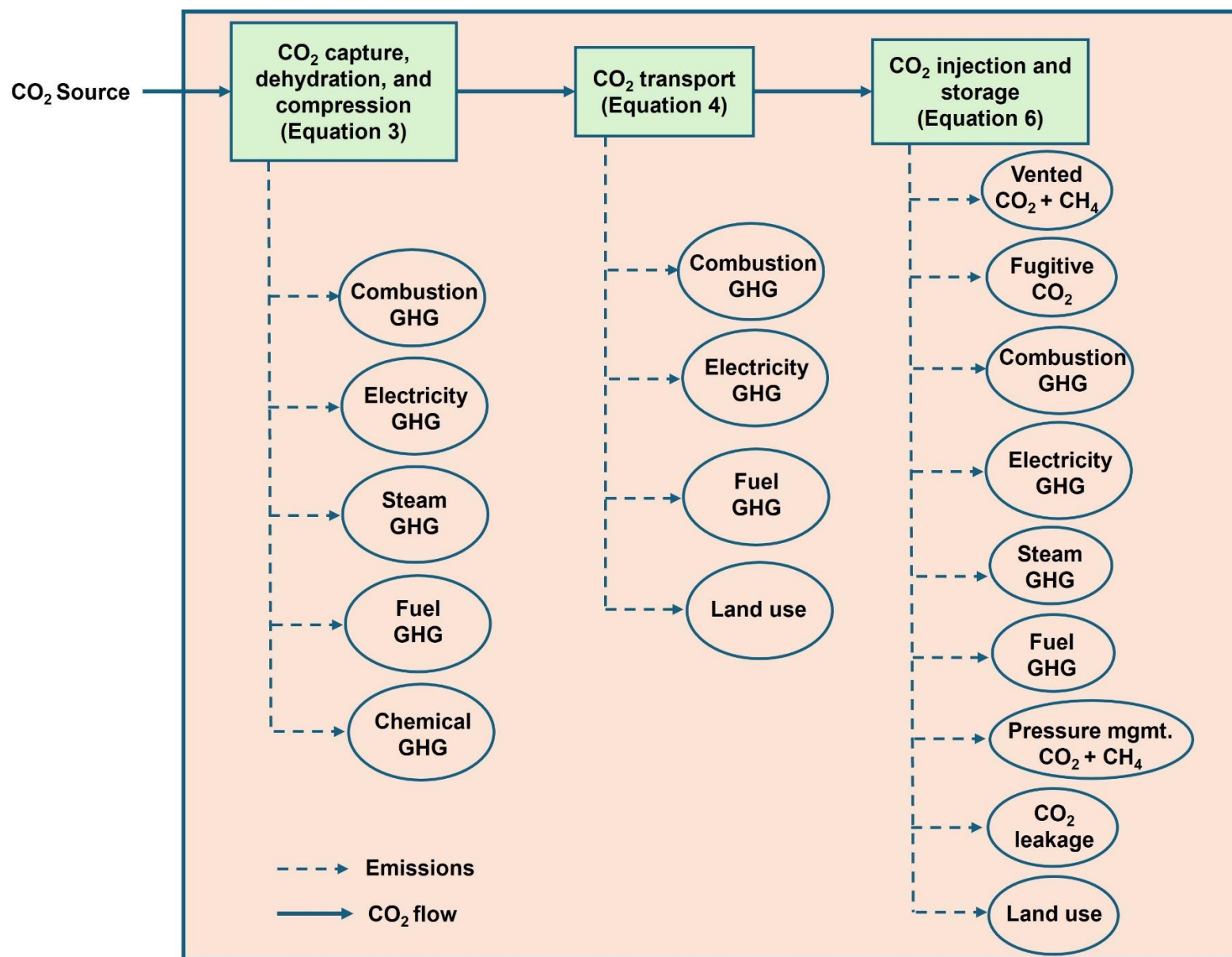


Figure 2. Project boundary for CO₂ capture and sequestration in depleted oil and gas reservoirs and saline formations.

Chapter 3. Quantification of CCS Project GHG Emission Reductions

This chapter describes the methodology for estimating GHG emissions reductions by sequestering CO₂ in depleted oil and gas or saline reservoirs and through EOR.

3.1. Covered Greenhouse Gas Emissions for GHG accounting

- (a) In addition to CO₂, CH₄, and N₂O, CA-GREET accounting treats VOCs and CO as GHGs because they are eventually oxidized to CO₂.
- (b) In the context of CCS projects, emissions covered in this document under the LCFS are CO₂, N₂O, CH₄, CO and VOC.
- (c) The global warming potential values listed in CA-GREET model are used to determine the CO₂ equivalent of emissions.
- (d) If N₂O, CH₄, CO and VOC present in the CO₂ stream are sequestered during CO₂ injection, they are not included in the quantification and will not be credited under LCFS.

3.2. Greenhouse Gas Emissions Calculation

Note: CCS Project Operators are required to submit either quarterly or annual project reports. The units in Equations 1 through 6 are expressed as either MT CO₂e per year or MT CO₂e per quarter, depending on the reporting frequency selected by the project for verification and transaction.

- (a) Net GHG emissions reductions from CCS projects must be quantified using Equation 1.

$$GHG_{net\ reduction} = CO_{2\ injected} - GHG_{project} \quad (1)$$

Where:

$GHG_{net\ reduction}$ = Net GHG reductions.

$CO_{2\ injected}$ = Amount of injected CO₂.

Excludes recycled CO₂ in the case of CO₂-EOR (equal to purchased CO₂ measured before the point of injection and after transportation).

$GHG_{project}$ = CCS project GHG emissions.

- (b) If the injected CO₂ consists of CO₂ derived from various sources/facilities, a mass-balance approach must be used to assign the injected amount to the various sources of carbon capture based on metered data and contractual agreements between the CO₂ supplier and GCS operator. CO₂ from natural underground CO₂ reservoirs must be omitted from $CO_{2injected}$.
- (c) CCS project GHG emissions must be calculated using Equation 2. Each variable in the equation must include both direct emissions as well as upstream (indirect) emissions associated with the corresponding specific activity and must be determined pursuant to subchapters 3.2(c) through 3.2(v) below.

$$GHG_{project} = GHG_{capture} + GHG_{transport} + GHG_{injection} + GHG_{dLUC} \quad (2)$$

Where:

$GHG_{project}$ = CCS project GHG emissions.

$GHG_{capture}$ = GHG emissions associated with carbon capture, dehydration, and compression.

$GHG_{transport}$ = GHG from CO₂ transport.

Transport can be by pipeline, ships, rail, or trucks

$GHG_{injection}$ = GHG emissions from injection operations.

GHG_{dLUC} = GHG emissions from direct land use change for transport and injection.

- (d) Installation of new pipelines and construction of new CO₂ injection sites can cause changes in above and belowground carbon stock depending on the type of land use where these facilities are going to be located. In such a case, direct land use change GHG emissions must be calculated using land use change emission factors utilized in the Global Trade Assessment Project model or using similar CARB-approved land use change emission factors. Direct land use change emissions must be amortized over a period of 30 years. If CCS projects utilize existing pipeline and CO₂ injection infrastructure where land use change has already occurred, direct land use change emissions are considered part of the baseline and are not considered. Indirect land use change GHG emissions are omitted from the quantification requirements since they are considered negligible.
- (e) GHG emissions from carbon capture, dehydration, and compression must be calculated according to Equation 3. GHG emissions from fuel combustion and electricity use must be determined by using emission factors available in CA-

GREET. If an emission factor for a particular fuel is not available in CA-GREET or in Appendix E, applicants must apply to CARB for approval to use an emission factor from an alternative source.

$$GHG_{capture} = GHG_{combustion} + GHG_{electricity+steam} + GHG_{fuel} + GHG_{chemical} \quad (3)$$

Where:

$GHG_{capture}$ = GHG emissions from capture, dehydration, and compression.

$GHG_{combustion}$ = GHG emissions from fuel combustion in stationary equipment including emissions from parasitic load.

$GHG_{electricity+steam}$ = GHG emissions from purchased electricity and steam.

GHG_{fuel} = GHG emissions from production and transport of fuel used in stationary equipment including emissions associated with parasitic load.

$GHG_{chemical}$ = GHG emissions from production and transport of chemicals used in carbon capture, including replacements from loss/deterioration.

Depending on the technology used, carbon capture may involve the use of chemicals such as monoethanolamine (MEA), NaOH, and activated carbon.

- (f) GHG emissions from fuel combustion ($GHG_{combustion}$) must be calculated using the volume of fuels used, and their corresponding emission factors provided in CA-GREET. If specific emission factors are not available in CA-GREET, applicants must submit a request to CARB for approval of emissions factors.
- (g) GHG emissions from electricity must be calculated using electricity emission factors in CA-GREET. GHG emissions from steam must be calculated based on the enthalpy of steam, the fuel source and type, the emission factor of the fuel used, and the efficiency of the boiler or the cogeneration system.
- (h) GHG emissions of chemicals ($GHG_{chemical}$) must be calculated using CA-GREET or must submit a request to CARB to use an equivalent method if the chemical in question is not modelled in CA-GREET.

- (i) GHG emissions of fuel (GHG_{fuel}) must be calculated using the CA-GREET model or an equivalent method if the fuel in question is not modelled in CA-GREET.
- (j) GHG emissions from CO₂ transport must be calculated using Equation 4.

$$GHG_{transport} = GHG_{combustion} + GHG_{electricity} + GHG_{fuel} \quad (4)$$

Where:

$GHG_{transport}$ = GHG emissions from CO₂ transport.

$GHG_{combustion}$ = GHG emissions from fuel combustion at stationary equipment used in CO₂ transport.

$GHG_{electricity}$ = GHG emissions from electricity use in CO₂ transport.

GHG_{fuel} = GHG emissions from production and transport of fuels used in CO₂ transport.

- (k) If a pipeline carries CO₂ to multiple geological sites or serves multiple uses, CO₂ transport emissions must be prorated using the mass-based allocation method and assigned to the CCS project under consideration.
- (l) If the injected CO₂ comes via two or more different transport modes, $GHG_{transport}$ must be calculated and summed together for each transport mode.
- (m) GHG emissions from CO₂ injection operations must be calculated using Equation 5 for CO₂-EOR and Equation 6 for depleted oil and gas reservoirs and saline formations.
- (n) GHG emissions from fuel combustion, electricity use, and emissions from production of fuels are only from operations related to CO₂ injection and recycling operations only (within the project boundary). GHG emissions associated with fuel combustion, electricity use and emissions of fuels used for other activities at the injection site (outside the project boundary) are excluded because the emissions are assigned to the other activities.

$$GHG_{injection} = GHG_{combustion} + GHG_{electricity+steam} + GHG_{fuel} + CO_{2vent} + CO_{2fugitive} + CO_{2entrained} + CO_{2leakage} + CO_{2transfer} \quad (5)$$

Where:

$GHG_{injection}$	=	GHG emissions in CO ₂ e associated with injection operations in CO ₂ -EOR.
$GHG_{combustion}$	=	GHG emissions from fuel combustion at stationary equipment used in CO ₂ injection and recycling.
$GHG_{electricity+steam}$	=	GHG emissions from electricity and steam used in CO ₂ injection and recycling.
GHG_{fuel}	=	GHG emissions from production and transport of fuels used (excluding electricity) in CO ₂ injection and recycling.
CO_2_{vent}	=	CO ₂ emissions from venting including biogenic CO ₂ and CO ₂ from direct air capture.
$CO_2_{fugitive}$	=	Fugitive CO ₂ emissions from surface equipment including biogenic CO ₂ and CO ₂ from direct air capture.
$CO_2_{entrained}$	=	Entrained CO ₂ in produced water, natural gas, and crude oil downstream of separator units. Excludes entrained CO ₂ if it is reinjected into reservoirs. Entrained CO ₂ emissions are calculated using the formula provided in Appendix F.
$CO_2_{leakage}$	=	Atmospheric CO ₂ leakage from the storage complex. Includes subsurface and atmospheric leakage.
$CO_2_{transfer}$	=	Intentional transfer of stored CO ₂ outside of the CCS project GCS site boundary.

And:

$$GHG_{injection} = GHG_{combustion} + GHG_{electricity+steam} + GHG_{fuel} + GHG_{vent} + GHG_{pressure} + CO_{2fugitive} + CO_{2leakage} \quad (6)$$

Where:

- | | | |
|--|---|---|
| <i>GHG_{injection}</i> | = | GHG emissions in CO ₂ e associated with injection operations. |
| <i>GHG_{combustion}</i> | = | GHG emissions from fuel combustion at stationary equipment used in CO ₂ injection. |
| <i>GHG_{electricity+steam}</i> | = | GHG emissions from electricity and steam used in CO ₂ injection. |
| <i>GHG_{fuel}</i> | = | GHG emissions from production and transport of fuels used (excluding electricity) in CO ₂ injection. |
| <i>GHG_{vent}</i> | = | CO ₂ and CH ₄ emissions from venting. |
| <i>GHG_{pressure}</i> | = | CO ₂ and CH ₄ emissions from pressure management activities including brine production. |
| <i>CO₂ fugitive</i> | = | Fugitive CO ₂ emissions from surface equipment including biogenic CO ₂ and CO ₂ from direct air capture. |
| <i>CO₂ leakage</i> | = | CO ₂ leakage from the storage complex. Includes subsurface and atmospheric leakage. |
- (o) There are planned and unplanned venting events in CO₂ injection operations. Both must be accounted for in this Methodology. For CO₂-EOR, these must include any CO₂ taken out of the ground but not reinjected into wells towards the end of EOR project completion, and any CO₂ blowdown.
- (p) Vented CO₂ emissions from CO₂-EOR must be determined for each applicable venting source using the methods described in Appendix B. In the case of CO₂ injection operations in depleted oil and gas or saline reservoirs, vented CO₂ emissions from surface facilities must be calculated using the event-based approach described in Appendix A(b). This must include CO₂/CH₄ releases from pressure management including brine production.
- (q) In the case of CO₂-EOR operations, fugitive CO₂ emissions must be calculated using either leak detection and leaker emission factors, or using population count and emission factors as described in Appendix B. Fugitive CO₂ emissions occur from fittings, flanges, valves, connectors, meters, and headers associated with CO₂-EOR operations. In the case of CO₂ injection operations in depleted oil and

gas reservoirs/saline formations, fugitive CO₂ and CH₄ emissions from equipment must be calculated using the equipment count method described in Appendix A(a).

- (r) In the case of CO₂-EOR operations, CO₂ can remain in water, natural gas and crude oil after they are separated from produced CO₂ in separators for either sales or disposal/injection of water. CO₂ from these product streams will eventually be released and must be calculated using Equation F.1 in Appendix F.
- (s) To be conservative, CO_{2leakage} must be considered to be equal to half the detection limit of the method used to detect leaks deployed in the GCS site's Testing and Monitoring Plan under the GCS Protocol, or the volume of leakage detected, whichever is greater. The CCS Project Operator must provide a description and justification for the method used to calculate the detection limit.
- (t) In cases where atmospheric or subsurface leakage has occurred, CO_{2leakage} must be calculated using a method identified in the GCS site's Testing and Monitoring Plan under the GCS Protocol.
- (u) In the event the stored CO₂ is intentionally released via decompression and transferred to other EOR locations it must be counted as emissions and included in CO_{2transfer}. The new location can apply under the GCS Protocol.
- (v) For the purpose of estimating LCFS CCS credits, data measurement/generation and reporting requirements for energy and chemical inputs are described in Appendix D.

3.3. Invalidation and Buffer Account

- (a) LCFS credits issued for verified GHG emissions reductions associated with CCS projects will be invalidated if the sequestered CO₂ associated with the GHG emissions reductions migrate outside the storage complex or is released to the atmosphere.
- (b) The amount of verified GHG emissions reductions to be invalidated for a CCS project is equal to the CO₂ leakage from the storage complex occurring after credit issuance, which must be determined in accordance with the GCS Protocol, section C.4.3.2.
- (c) The following will apply to all CCS projects seeking credit issuance under sections 95490(h)(3) and (4) of the LCFS.
 - (1) All CCS projects must have received Permanence Certification under the GCS protocol;

- (2) All CCS projects must contribute a number of LCFS credits to the Buffer Account at the time of LCFS credit issuance by CARB; and
- (3) The CCS project's contribution to the Buffer Account is determined by Equation 7 using the project-specific risk rating from the GCS Protocol Appendix A:

$$\text{Buffer Contribution} = CO_{2\text{ injected}} \times \text{GCS Site Risk Rating} \times \frac{\text{credits}}{\text{MT CO}_2} \quad (7)$$

Where:

Buffer Contribution = Number of credits

CO₂ injected = Amount of injected CO₂ (MT CO₂).

GCS Site Risk Rating = Projects overall risk rating using Equation A.1 from the GCS Protocol Appendix A.

- (d) If permanence certification is rescinded, then all sequestered CO₂ is considered released and all LCFS credits issued as a result of the sequestered CO₂ will be invalidated.

Chapter 4. Monitoring, Reporting, and Verification

4.1. Monitoring Requirements for Quantification

- (a) In addition to the Testing and Monitoring Plan required under the GCS Protocol for purposes of permanence certification and compliance, the CCS Project Operator must complete and retain for review by a verifier, or the Executive Officer, a written monitoring plan that meets all the requirements of section 95491.1 of the LCFS Regulation. This may be a single monitoring plan for both the LCFS and CCS Methodology.
- (b) The monitoring plan must contain the following items specific to the CCS project:
 - (1) A list of all relevant parameters to account for all variables required for the calculation of *GHG_{net reduction}* in Chapter 3.
 - (2) Sufficient data capture to ensure that the quantification and documentation of CO₂ sequestered is replicable and verifiable pursuant to the quantification requirements of Chapter 3.
 - (3) A description of the methods, and an estimate of precision and accuracy of the methods used to measure and quantify CO₂ leakage after credit issuance from the storage complex, as required by this Methodology and GCS protocol.
 - (4) CCS project monitoring techniques must use calibrated metering equipment such as flow meters, utility meters (gas and electricity), and chemistry analyzers. All devices used for calculating *GHG_{net reduction}* must meet the accuracy, and monitoring and recording frequencies of the LCFS regulation.
 - (5) Documentations of any assumptions and contingencies.

4.2. Reporting for Verification

- (a) For crediting purposes, CCS Project Operators are required to submit quarterly or annual (depending on how often the project elects to undergo verification) project reports and fuel pathway reports¹ of GHG emissions reductions and ongoing monitoring results. Reports must include the quantification of GHG emissions reductions and documentation of CO₂ injected pursuant to the quantification requirements in Chapter 3. Data quality management must be sufficient to support quantification and verification of GHG emissions reductions and CO₂ injected. Reports must comply with the documentation, submittal, and timing requirements in the LCFS Regulation and should be submitted as part of

¹ For projects and pathways that elect to report and credit quarterly all references to annual or year/ly in the Methodology should be replaced by quarter/ly.

annual or quarterly reporting pursuant to the LCFS Regulation. Verification may only be conducted after the CCS Project Operator submits the appropriate report and attests that the reported information is true, accurate, and complete.

- (b) CCS Project Operators must submit applicable quarterly or annual reports that include:
 - (1) Data required to complete all the calculations in Chapter 3;
 - (2) Analysis of the CO₂ stream following GCS Protocol, section B.2(b); and
 - (3) Injection rate and volume pursuant to GCS Protocol, section B.3(e).

4.3. Verification

- (a) CCS projects must be verified pursuant to sections 95500 through 95503 of the LCFS Regulation, and the requirements of the GCS Protocol.
- (b) Each verification team must include:
 - (1) A CARB-accredited oil and gas systems specialist pursuant to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions section 95131(a); and
 - (2) A professional geologist licensed under Chapter 12.5 of Division 3 of the California Business and Professions Code §§ 7800 – 7887, or equivalent professional geologist approved by CARB. An explanation demonstrating that the verification team includes a professional geologist with the required experience and expertise must be included in the Notice of Verification Services.
 - (3) The required experience and expertise may be demonstrated by a single individual, or by a combination of individuals.
 - (4) The verification team must be the same verification team used to certify permanence pursuant to the GCS Protocol.
- (c) Verification must include a review of the following:
 - (1) Documentation and maps to verify the boundaries of the project, including the location of monitoring and measurement equipment, procedures for data quality assurance and quality control, and monitoring plan; and
 - (2) The determination of the projects contribution to the LCFS Buffer Account.

- (3) Conformance with the LCFS Regulation, Greenhouse Gas Quantification Methodology for Carbon Capture and Sequestration under the LCFS, and the requirements of GCS Protocol.
- (4) A separate verification statement is not required for the CCS Project. The material misstatement evaluation and conformance review will be included in the verification statement for LCFS.

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Appendix A. Fugitive and Vented GHG Emissions: Injection into Depleted Oil and Gas and Saline Formations

(a) Fugitive CO₂ Emissions: Equipment Count Method

Count each component (e.g., valves, connectors, open-ended lines) individually for the facility and multiply with default emission factors specific to component type. Alternatively, count the number of major pieces of equipment and multiply by the average number of components per major piece of equipment to arrive at the total number of each component for a facility. Calculate fugitive CO₂ emissions using Equation A.1.

$$E_{s,i} = \sum Count_i \times EF_i \times C_{CO_2} \times T_s \quad (A.1)$$

Where:

$E_{s,i}$	=	Volumetric fugitive CO ₂ emissions at standard conditions from i^{th} component type in cubic feet per reporting timeframe.
$Count_i$	=	Total number of i^{th} component type at the facility. If project specific component counts are not available, the component count values from Table E5 must be used. If the equipment type is not available in Table E5, the applicant must apply to CARB for a method to determine component counts.
EF_i	=	Emission factor for i^{th} component type (scf/hour/component). Use the CO ₂ values from Table E4. Any component type not listed in Table E4 must use the “Other” component type. Methane emission factors can be used as proxy for CO ₂ emission factors.
C_{CO_2}	=	CO ₂ concentration (%)
T_s	=	Total time that each component type associated with the equipment leak emission was operational per reporting timeframe, in hours. Unless monitored the default value of 8,760 hours will be used.

$E_{s,i}$ must be converted to MT CO₂/year or MT CO₂/quarter using the method described in Appendix C to obtain estimate $CO_{2\text{fugitive}}$ included in previous equations.

(b) Vented Emissions: Event-Based Approach

Calculate vented CO₂ emissions by measuring/estimating CO₂ emissions per venting event, and account for CH₄ emissions for all venting events at storage site per reporting timeframe using Equation A.2.

$$GHG_{vent} = \sum_{i=1}^n V_i \quad (A.2)$$

Where:

GHG_{vent} = Vented CO₂ and CH₄ emissions (MT CO₂e/year or MT CO₂e/quarter).

V_i = Vented CO₂ and CH₄ emissions for i^{th} vented event (MT CO₂e/event).

Appendix B. CO₂ Venting and Fugitive Emissions from CO₂-EOR Operations

- (a) Metered natural gas pneumatic device and pump vented CO₂ emissions.
 - (1) Calculate CO₂ emissions from a natural gas-powered continuous high bleed control device and pneumatic pump vented using the method specified in section 95153(a) in the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (MRR)² when the natural gas flow to the device is metered.
- (b) Non-metered natural gas pneumatic device vented emissions.
 - (1) Calculate CO₂ emissions from all non-metered natural gas-powered pneumatic intermittent bleed and continuous low and high bleed devices using the equation in section 95153(a) of MRR.
- (c) Acid gas removal vents.
 - (1) For AGR vents (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), calculate emissions for CO₂ only (not CH₄) vented directly to the atmosphere or emitted through a flare, engine (e.g., permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement), or sulfur recovery plant using the applicable calculation methodologies described in section 95153(c) of MRR.
- (d) Dehydrator vents.
 - (1) Calculate annual CO₂ emissions using any of the calculation methodologies described in section 95153(d) of MRR.
- (e) Gas well vented CO₂ emissions during well completions and workovers.
 - (1) Use either the Methodology 1 or 2 described in section 95153(f) of MRR.
- (f) Equipment and pipeline blowdowns.
 - (1) Calculate CO₂ blowdown emissions from depressurizing equipment and natural gas pipelines to reduce system pressure for shutdowns resulting from human intervention or to take equipment out of service for maintenance (excluding depressurizing to a flare, over-pressure relief, operating pressure control vented and blowdown of non-GHG gases using the methods described in 95153(g). Desiccant dehydrator blowdown vented before reloading is covered in section 95153 (d) of MRR.

² Final Regulation Order, Amendments to the Regulation, Mandatory Reporting of Greenhouse Gas Emissions Regulation. CARB, filed with Secretary of State September 1, 2017.

- (g) Dump valves.
 - (1) Calculate CO₂ emissions from gas-liquid separator liquid dump valves not closing by using the method found in section 95153(i) of MRR.
- (h) Well testing vented emissions.
 - (1) Calculate CO₂ vented from oil well testing using the methods found in section 95153(j) of MRR.
- (i) Associated gas.
 - (1) Calculate CO₂ in associated gas vented not in conjunction with well testing using the methods found in section 95153(k) of MRR.
- (j) Centrifugal compressor vented emissions.
 - (1) Calculate CO₂ emissions from both wet seal and dry seal centrifugal compressor using the methods described in section 95153(m) of MRR.
- (k) Reciprocating compressor vented emissions.
 - (1) Calculate CO₂ emissions from all reciprocating compressor vents using the methods described in section 95153 of MRR.
- (l) EOR injection pump blowdown emissions.
 - (1) Calculate CO₂ pump blowdown emissions from EOR operations using critical CO₂ injection using Equation 33 as described in section 95153(u) of MRR.
- (m) Fugitive CO₂ emissions from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps).
 - (1) Perform leak detection tests in accordance with procedures as described in the MRR. If CO₂ leakage is detected from the equipment listed above during annual leak detection tests, calculate fugitive emissions (CO₂) per component type in which leak is detected using Equation 25 in section 95153(o) of MRR for each component type. Default fugitive emission factors for Equation 25 are reported in Tables E4 to E6; or
 - (2) Calculate fugitive emissions from all equipment using the population count and emission factors as described in section 95153(p) of MRR.

Appendix C. Converting Volume of CO₂ to Mass

- (a) When volumetric emissions of CH₄ and CO₂ are measured at actual temperatures and pressures, convert them to volumetric emissions at standard conditions (25°C and 1 atm) using Equation 30 in MRR².
- (b) Calculate GHG mass emissions by converting the GHG volumetric emissions at standard conditions into mass emissions using Equation 32 described in section 95153(t) of MRR.

Appendix D. Data Measurement/Generation and Reporting for Energy and Chemical Inputs

(a) Amounts of fuels used:

- (1) Fuel receipts/invoices or flow meter readings whichever applicable;
- (2) The flow meter readings must be corrected for temperature and pressure. Density estimates used for emission quantification purposes must be adjusted to corrected standardized temperatures and pressures;
- (3) Flow meters must be placed based on manufacturer recommendations and must operate within manufacturers specified operating conditions at all times; and
- (4) Flow meters must be calibrated according to manufacturer specifications and must be checked and calibrated at regular intervals according to these specifications.
- (5) In cases where the same fuel is used for CCS and other unrelated activities and share the same meter or receipts/invoices, or when fuel receipts/invoices or metered data are not available, estimates with justification for the chosen methodology can be used with approval from CARB.

(b) Electricity consumption:

- (1) Utility receipts/invoices or metered data for off-grid electricity use. In the absence of these data, maximum power rating for each type of equipment and operating hours can be used to estimate electricity use with approval from CARB.
- (2) In certain cases, other loads may be tied into the same electricity meter. In such instances, estimates with justification for the chosen methodology can be used with approval from CARB.
- (3) Electricity meters must be calibrated in accordance with manufacturer specifications and must be checked and calibrated at regular intervals according to these specifications.

(c) Steam consumption:

- (1) Utility receipts/invoices or metered data for on-site steam production whichever applicable.

- (2) In the absence of utility receipts/invoices or metered data, estimates with justification for the chosen methodology can be used with approval from CARB.
- (3) If metered data are used, meters must be calibrated in accordance with manufacturer specifications and must be checked and calibrated at regular intervals according to these specifications.

(d) Cogeneration:

If any part of the CCS project uses electricity and thermal energy steam supplied directly by co-generation, the amount of fuel use associated with the electricity and thermal energy steam must be estimated using Equations D.1 and D.2.

$$Fuel_{electricity} = Total\ Fuel_{cogen} \times f_{electricity} \quad (D.1)$$

$$Fuel_{steam} = Total\ Fuel_{cogen} \times f_{steam} \quad (D.2)$$

Where:

$Fuel_{electricity}$ = Amount of fuel attributed to electricity production in mmbtu.

$Fuel_{steam}$ = Amount of fuel attributed to steam production in mmbtu.

$Total\ Fuel_{cogen}$ = Total fuel combusted by the cogeneration unit supplying electricity and/or steam to the CCS Project.

$$f_{electricity} = \frac{\frac{Electricity\ Generation}{0.35}}{\frac{Electricity\ Generation}{0.35} + \frac{Steam\ Generation}{0.8}}$$

$$f_{steam} = 1 - f_{electricity}$$

Where, $f_{electricity}$ and f_{steam} are the allocation factors for electricity and steam, respectively. Electricity Generation represents total electricity (mmbtu) produced by the co-generation unit. Steam Generation represents the energy (mmbtu) of the steam generated from the available exhaust heat from the co-generation unit.

(e) Chemical inputs:

- (1) Purchase receipts/invoices or flow meter readings whichever applicable.

Appendix E. Emission Factors and Component Counts

Note: Stationary emissions factors in Tables E1 to E3 may be used only if they are not available in CA-GREET.

Table E1. Stationary Emission Factors for Fossil Fuel Combustion³

Coal and Coke	kg CO₂/ton	g CH₄/ton	g N₂O/ton
Anthracite (coal)	2602	276	40
Bituminous (coal)	2325	274	40
Sub-bituminous (coal)	1676	190	28
Lignite	1389	156	23
Mixed (commercial)	2016	235	34
Mixed (electric power sector)	1885	217	32
Mixed (industrial sector)	2468	289	42
Mixed (commercial)	2116	246	36
Coal Coke	2819	273	40
Fossil-derived Fuels (solid)	kg CO₂/ton	g CH₄/ton	g N₂O/ton
Municipal Solid Waste	902	318	42
Petroleum Coke (Solid)	3072	960	126
Plastics	2850	1216	160
Tires	2407	896	118
Fossil-derived Fuels (gaseous)	kg CO₂/scf	g CH₄/scf	g N₂O/scf
Blast Furnace Gas	0.02524	0.000002	0.000009
Coke Oven Gas	0.02806	0.000288	0.00006
Fuel Gas	0.08189	0.004164	0.000833
Propane Gas	0.15463	0.000055	0.000252

Note: Ton refers to short ton. While using Tables E1 to E3, CO and VOC emissions may need to be estimated if possible.

³ US EPA. Direct Emissions from Stationary Combustion Sources. (2016). Available at https://www.epa.gov/sites/production/files/2016-03/documents/stationaryemissions_3_2016.pdf

Table E2. Stationary Emission Factors for Petroleum Fuel Combustion³

Petroleum Products	kg CO₂/gal	g CH₄/gal	g N₂O/gal
Asphalt and Road Oil	11.91	0.47	0.09
Aviation Gasoline	8.31	0.36	0.07
Butane	6.67	0.31	0.06
Butylene	7.22	0.32	0.06
Crude Oil	10.29	0.41	0.08
Distillate Fuel Oil No .1	10.18	0.42	0.08
Distillate Fuel Oil No .2	10.21	0.41	0.08
Distillate Fuel Oil No. 4	10.96	0.44	0.09
Ethane	4.05	0.2	0.04
Ethylene	3.83	0.17	0.03
Heavy Gas Oils	11.09	0.44	0.09
Isobutane	6.43	0.3	0.06
Isobutylene	7.09	0.31	0.06
Kerosene	10.15	0.41	0.08
Kerosene-Type Jet Fuel	9.75	0.41	0.08
Liquefied Petroleum Gases (LPG)	5.68	0.28	0.06
Lubricants	10.69	0.43	0.09
Motor Gasoline	8.78	0.38	0.08
Naphtha (<401 deg F)	8.5	0.38	0.08
Natural Gasoline	7.36	0.33	0.07
Other Oil (>401 deg F)	10.59	0.42	0.08
Pentanes Plus	7.7	0.33	0.07
Petrochemical Feedstocks	8.88	0.38	0.08
Petroleum Coke	14.64	0.43	0.09
Propane	5.72	0.27	0.05
Propylene	6.17	0.27	0.05
Residual Fuel Oil No. 5	10.21	0.42	0.08
Residual Fuel Oil No. 6	11.27	0.45	0.09
Special Naphtha	9.04	0.38	0.08
Unfinished Oils	10.36	0.42	0.08
Used Oil	10.21	0.41	0.08

Table E3. Stationary Emission Factors for Petroleum Fuel Combustion³

Biomass-Derived Fuels (Solid)	kg CO₂/ton	g CH₄/ton	g N₂O/ton
Agricultural Byproducts	975	264	35
Peat	895	256	34
Solid Byproducts	1096	332	44
Wood and Wood Residuals	1640	126	63
Biomass -Derived Fuels (gaseous)	kg CO₂/scf	g CH₄/scf	g N₂O/scf
Landfill Gas	0.025254	0.001552	0.000306
Other Biomass Gases	0.034106	0.002096	0.000413
Biomass Fuels (liquid)	kg CO₂/gal	g CH₄/gal	g N₂O/gal
Biodiesel (100%)	9.45	0.14	0.01
Ethanol (100%)	5.75	0.09	0.01
Rendered Animal Fat	8.88	0.14	0.01
Vegetable Oil	9.79	0.13	0.01
Biomass Fuels (Kraft Pulping Liquor by Wood Furnish)	kg CO₂/MMbtu	g CH₄/MMbtu	g N₂O/MMbtu
North American Softwood	94.4	1.9	0.42
North American Hardwood	93.7	1.9	0.42
Bagasse	95.5	1.9	0.42
Bamboo	93.7	1.9	0.42
Straw	95.1	1.9	0.42

Table E4. Default CO₂ Emission Factors²

Component	Emission Factor (scf/hour/component)
Valve	0.121
Connector	0.017
Open-ended Line	0.031
Pressure Relief Valve	0.193
Low Continuous Bleed Pneumatic Device Vents	1.39
High Continuous Bleed Pneumatic Device Vents	37.3
Intermittent Bleed Pneumatic Device Vents	13.5
Pneumatic pumps	13.3
Other	0.30

Table E5. Default Average Component Counts²

Equipment	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves
Wellheads	11	36	1	0
Separators	34	106	6	2
Meters/Piping	14	51	1	1
Compressors	73	179	3	4
In-Line Heaters	14	65	2	1
Dehydrators	24	90	2	2

Appendix F. Emissions from CO₂ Entrained in Produced Oil and Gas

(a) Annual CO₂ Fugitive Emissions Entrained in Produced Oil and Gas⁴

$$CO_{2\text{ entrained}} = (V_{\text{gas}} \times \%CO_{2\text{ gas}} \times \rho_{CO_2} \times 0.001) + (M_{\text{water}} \times F_{CO_2\text{-water}}) + (M_{\text{oil}} \times F_{CO_2\text{-oil}}) \quad (\text{F.1})$$

Where:

$CO_{2\text{ entrained}}$ = Emissions or other losses of CO₂ entrained or dissolved in crude oil/other hydrocarbons, produced water and natural gas that have been separated from the produced CO₂ for sale or disposal. Calculated based on quantities of crude oil, water and gas produced and the CO₂ content of each product (MT CO₂/year or MT CO₂/quarter).

V_{gas} = Volume of natural gas or fuel gas, produced from the formation that CO₂ is being injected into, that is sold to third parties or input into a natural gas pipeline in the reporting timeframe (m³/year or m³/quarter), measured at standard conditions.

ρ_{CO_2} = Density of CO₂ at standard conditions (1.899 kg/m³ or 0.0538 kg/ft³).

$\%CO_{2\text{ gas}}$ = % CO₂ in the natural gas or fuel gas that is sold to third parties or input into a natural gas pipeline in the reporting timeframe (% volume).

M_{water} = Mass of water produced from the formation that CO₂ is being injected into, that is disposed of or otherwise not re-injected back into the formation (MT/year or MT/quarter)

$F_{CO_2\text{-water}}$ = Mass fraction of CO₂ in the water produced from the formation.

⁴ The American Carbon Registry “Methodology for Greenhouse Gas Emission Reductions from Carbon Capture and Storage Projects,” Version 1 (2015). Available at <http://americancarbonregistry.org/carbon-accounting/standards-methodologies/carbon-capture-and-storage-in-oil-and-gas-reservoirs/acr-ccs-methodology-v1-0-final.pdf>.

M_{oil}	=	Mass of crude oil and other hydrocarbons produced from the formation that CO ₂ is being injected into (MT/year or MT/quarter).
$F_{CO2-oil}$	=	Mass fraction of CO ₂ in the crude oil and other hydrocarbons produced from the formation.