Quantification Protocol for Enhanced Oil Recovery

Technology Innovation and Emissions Reduction (TIER) Regulation
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# Summary of Revisions

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| Final 2.0             | January 2022 | - Priced and non-priced emissions section was updated.  
- Clarified: Holdback return process and CO₂ Transfers  
- Added Containment Assurance Report Template  
- Described the Director approval conditions for pre-registration of EOR emission offset projects  
- Further defined offset project to include one EOR scheme Approval Area  
- Provided quantification for Type 1 and Type 2 CO₂ transfers and for reversals.  
- The crediting period was extended |
| Draft for public post | March 2020 | - The Protocol Scope was modified to reflect the carbon dioxide emissions and handling and to exclude the oil production and oil handling emissions and to cover various stages and activities of projects that will use the protocol.  
- Protocol applicability conditions and Protocol Flexibility mechanisms were modified to suit the modified scope.  
- The Baseline Condition was updated to include relevant sources, sinks and reservoirs (SSRs) for the modified scope.  
- The Project Condition was updated to include relevant SSRs for the modified scope.  
- The Quantification Methodology was revised to account for the modified scope and to align as closely as possible to the carbon capture and storage offset protocol.  
- The Documents and Records requirements were clarified. The contingent data collection procedures and quality assurance and quality control were updated.  
- Levied and non-levied emissions section was added.  
- The emission offset project developer must obtain Director approval prior to project initiation on the Alberta Emissions Offset Registry.  
- Transfers of CO₂ and the associated holdback are allowed for Type 2 EOR schemes, when the remaining holdback is greater than 2% of the total cumulative holdback from project. Other movement of CO₂ outside the project boundary is a project emission.  
- Updated flexibility mechanisms, some with requirements for Department approval. |
| 1.0                   | October 2007 | Version approved for use.                                                                                                                                                                                                                                                                                                                                 |

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Quantification Protocol for Enhanced Oil Recovery

Classification: Public
Related Publications

- *Emissions Management and Climate Resilience Act (the Act)*
- Technology Innovation and Emissions Reduction Regulation (the Regulation)
- Specified Gas Reporting Regulation
- Standard for Greenhouse Gas Emission Offset Project Developers (the Standard)
- Standard for Validation, Verification and Audit
- Technical Guidance for Offset Protocol Development and Revision
- Carbon Offset Emission Factors Handbook
- Quantification Protocol for CO₂ Capture and Permanent Storage in Deep Saline Aquifers
1. Offset Project Description

Capturing carbon dioxide (CO₂) that would otherwise be emitted to the atmosphere and utilizing it in Enhanced Oil Recovery (EOR) schemes can result in permanent net geological sequestration of CO₂. EOR schemes are typically operated with externally sourced CO₂ from industrial processes or power generation that are unrelated to the operation of the EOR scheme.

This quantification protocol establishes the methodology for quantifying the eligible greenhouse gas (GHG) emission reductions through net geological sequestration of CO₂ for EOR project activities. For this protocol only new (recently generated and captured), anthropogenic, CO₂ is eligible for emission offsets, CO₂ that was previously injected into a reservoir and recycled is ineligible for emission offsets. This protocol was developed using a life cycle analysis and included an evaluation of emissions from the following elements of a typical EOR activity scheme which includes:

- CO₂ capture infrastructure. Includes a process or process modification within a facility to capture CO₂ emissions. The carbon capture facility may be integrated or separate from the emission source facility, and may use any commercial CO₂ capture technology;
- CO₂ transportation system. The transportation system may be a pipeline including compression and/or pumps to transport CO₂ from the capture facility to the EOR injection well(s) and/or may be CO₂ moved by vehicle from the capture facility to the EOR injection well(s); and
- Net geological sequestration of CO₂ through CO₂ injection into an oil reservoir operating under an EOR Scheme Approval. Produced CO₂, emerging from the subsurface due to oil production is typically processed and reinjected (i.e. recycled) into the storage complex at CO₂ injection wells. Reinjected CO₂ quantities are not eligible for emission offsets in this quantification protocol to ensure no double counting of volumes. Applicable sources and sinks (SSs) are included in the project condition to account for situations where produced CO₂ is vented to atmosphere or transferred off site, (i.e. produced CO₂ that is vented to atmosphere is accounted for and quantified as a project emission).

Emission offset project developers using this protocol have familiarity with CO₂ capture and net geological sequestration projects in order to apply greenhouse gas quantification methodologies.

1.1. Protocol Scope

This protocol is applicable to emission reductions from the geological sequestration of CO₂ through enhanced oil recovery (EOR) activity in Alberta. This protocol is applicable only for emission reductions and sequestration that are not subject to a carbon price by any other policy mechanism and that are not required by law. Project activities which are in scope may include the capture of new CO₂, the compression, transport, injection, (inclusive of any re-injection) and the permanent net geological sequestration of CO₂. A process flow diagram for a typical CO₂-EOR project is shown in Figure 1.

This protocol does not apply to carbon capture and storage (CCS) activities in saline aquifers, or to acid gas injection schemes associated with sour natural gas processing operations. Emission offset project developers with CCS projects should refer to the applicable Alberta approved quantification protocol.

Protocol Approach

This protocol applies to CO₂-EOR emission offset projects where the imported CO₂ is from a large emitter or opt-in facility regulated under the provincial GHG Regulation, and would otherwise have been emitted to atmosphere and, under the project condition, is injected into an approved EOR scheme. This protocol provides the methodology for emission offset project developers to follow and outlines the requirements for measurement, monitoring, quantification and verification. The regulated facility reports the exported CO₂ as part of their Total Regulated Emissions (TRE).

Baseline Condition

A projection-based baseline is used to quantify the CO₂ emissions that would have otherwise been emitted to the atmosphere in the absence of the emission offset project. The baseline emissions are measured by metering the mass of new CO₂ injected into the EOR scheme and do not include the mass of any re-injected CO₂ (i.e. recycled CO₂), or from another EOR scheme that has generated emission offsets. Baseline emissions include injected CO₂ quantities only, not captured quantities. The scope of the greenhouse gases eligible under the baseline condition of this protocol is carbon dioxide only. The sequestration of methane or nitrous oxide is not eligible for emission offsets.

Project Condition

Project emissions which may be applicable to this activity include the CO₂ capture, compression, transport, injection, and re-injection activities associated with injecting CO₂ into an oil-producing geological formation. Enhanced oil recovery projects primarily sequester CO₂. However, the CO₂ stream may contain several impurities such as CH₄, N₂O, H₂S, nitrogen, etc. A wide range of light hydrocarbons and/or sulfur-based gases may be emitted as a result of CO₂ capture, compression, transport, injection, re-injection and venting.
The scope of greenhouse gases that must be included in the project condition includes all related emissions of CO₂, CH₄, and N₂O, as per the quantification section of this protocol.

**Emission Offset Project Developer**

The CO₂ capture, compression, transport and net geological sequestration may or may not be conducted by the emission offset project developer. It is likely that several entities may be involved in the project activities. Each entity must maintain the records that need to be available for verification/reverification of the emission offset project and must allow access to the records to any third party assurance provider.

The emission offset project developer as described in the Regulation is accountable for the project meeting the requirements of both the Regulation and the Standard for Greenhouse Gas Emission Offset Project Developers (the Standard). It’s the emission offset project developer’s responsibility to work with all entities to obtain access to all records, data and equipment that may be required for monitoring, measurement, quantification and verification and must retain all project records according to the requirements in the Regulation, the Standard and this protocol.

**CO₂ Capture Entity**

The CO₂ capture entity is the originator of records, data and equipment related to CO₂ capture that may be required for quantification and verification. This may include evidence of captured CO₂ quantities, including concentration or composition and records for any heat, power or fuel used on-site for CO₂ capture.

**Transport Entity**

The transport entity is the originator of records, data and equipment related CO₂ compression and transportation that may be required for quantification and verification. This may include evidence of delivered CO₂ quantities, including concentration or composition and records for any heat, power or fuel used on-site or fuel used to transport CO₂ by vehicles.

**Injection/Sequestration Entity**

The injection/sequestration entity is the originator of records, data and equipment related to CO₂ injection, reinjected CO₂ (i.e. recycled CO₂), as well as monitoring data and any emissions (downstream of the injection meter) that may be required for quantification and verification. This will include evidence of CO₂ composition, injected CO₂ quantities, evidence of closed loop re-injection system and records for any heat, power or fuel used on-site. Evidence of pressure monitoring as may already be required under project scheme regulatory approvals may also be provided.

1.2. Offset Crediting Period

The offset crediting period for this activity 20 years, with the possibility of a 5 year extension(s). The criteria for project extension period eligibility, is set out in the Standard for Greenhouse Gas Emission Offset Project Developers.

1.3. Protocol Applicability

Emission offset project developers must be able to demonstrate that the emission offset project meets the requirements of the Alberta emission offset system, the relevant greenhouse gas regulations, this quantification protocol, the Carbon Offset Emission Factors Handbook, and other related Standards and guidance documents.

The emission offset project developer must obtain a Director approval letter prior to project creation on the Alberta Emission Offset Registry. The Director approval is needed to ensure the project boundary, CO₂ source and eligibility requirements are met. The information required for the emission offset project developer’s submission will explain and provide evidence to demonstrate the project meets the following requirements:

1. A Director approval letter for the creation of an emission offset project on the Alberta registry using this quantification protocol. The emission offset project developer will submit a written request to the Director and must include; an explanation of the emission offset project activity, a description of the overall scope, how the project meets all applicability criteria outlined here as 2-6, any flexibility mechanism to be utilized, any plan for alternate sequestration or transfers of the CO₂ outside of the project boundary, a completed Reservoir Pressures Table (see Required Project Documentation Section), the CO₂-EOR Scheme Approval for the activity, and an explanation of any special conditions that may apply to the activity (i.e. see 7 below).

2. The emission offset project developer provides evidence to demonstrate that the CO₂ is captured from a large emitter or opted-in facility under the Regulation. This is demonstrated by actual EOR project schematics and by compliance with the measurement requirements set forth in the quantification section of this protocol.

3. The CO₂-EOR scheme must have obtained approval from the Alberta Energy Regulator (AER) under Directive 066 – Resources Applications for Conventional Oil and Gas Reservoirs and Section 39 of the Oil and Gas Act.

4. The emission offset project boundary must be clearly described, which includes the emissions system; the CO₂ sources and if they are inside or outside the project boundary, the transportation system, the EOR geologic pool called the scheme Approval Area and the surface locations. A clear delineation of where the large emitter or opt-in facility stops and the emission offset project starts is part of the description.

The physical boundary for injection will be equivalent to the boundary set out in the EOR scheme approval. The EOR emission offset project boundary includes:

- One EOR scheme approval and the geologic pool, called the scheme Approval Area, (the part of project boundary corresponding to the injection/sequestration entity), and
- The capture and transportation elements of the project unless the associated emissions are accounted for by the regulated facility,

5. The project must have obtained all required operating permits and relevant regulations in Alberta prior to emission offset project creation on the registry.

6. The net geological sequestration from the project must be quantified using actual measurements and monitoring as indicated in this protocol.

7. The emission offset project developer must provide confirmation of whether or not the project has any special conditions. These will require further details to be provided to the Director in order to obtain emission offset project approval, and include (but are not limited to):

- Projects with an EOR Scheme Approval that stipulate the reservoir pressure be reduced to or below the initial reservoir pressure, when production ceases or becomes very low.
- Projects that employ alternate technologies for CO₂ capture, transport, injection, or re-injection or use technologies and processes other than those commercially available and outlined in this protocol.

1.4. Flexibility Mechanisms

The quantification protocol is written for a single capture, single storage scenario (shown in Appendix A). If the project developer is implementing an emission offset project that is a single capture multiple storage, multiple capture single storage, or multiple capture multiple storage, they must measure CO₂ concentration or gas composition, and gas quantity according to the relevant scenarios shown in Appendix A. If the project developer would like to use a mass balance equation to calculate CO₂ concentration and/or prorate project emissions amongst project developers or EOR schemes they must apply one or both of the flexibility mechanisms (below) and fully justify the rationale for the flexibility mechanisms used. A clear explanation of the flexibility mechanism and alignment with the protocol quantification must be demonstrated and be verifiable.

Flexibility Mechanism 1:

This flexibility mechanism allows project developers to calculate (rather than measure) CO₂ concentration based on the weighted average in a single variable mass balance equation. The requirements for calculating CO₂ concentration for the various potential scenarios is outlined in Appendix A

Flexibility Mechanism 2:

This flexibility mechanism allows project developers to prorate their emissions based on the amount of eligible CO₂ they inject. In cases where:

- there are more than one EOR emissions offset project using the same capture and transport systems but different injection schemes, or
- there is more than one capture and compression facility using the same transport of CO₂ to the same injection schemes,

Then all associated projects must use the same proration approach and must clearly justify and explain the proration method and the metering scheme and in the project plan and the project report.

Flexibility Mechanism 3:

This flexibility mechanism allows project developers to source CO₂ from direct air capture facilities in Alberta, as an eligible source. Project Developers must notify the Director of their intent to utilize a DAC source, provide the details of the source facility and the expected quantity of CO₂ per year. Project developers using this source of CO₂ must additionally quantify all vented, flared and fugitive emissions upstream of the injection meters except for emissions of the captured CO₂. The quantification must meet the same rigor as for large emitters, as outlined in the TIER Quantification Methodology.
1.5. Risk Assurance –Discount Factors: Permanence and Holdback

CO₂-EOR project activities typically involve the injection of CO₂ into depleted oil pools until there is sufficient pressure for the CO₂ to become miscible with the oil in a single phase mixture, which helps move oil toward producing wells. It is expected that eventually CO₂ will be produced with the oil, and reinjected into the same EOR scheme for permanent storage.

1.5.1. Discount Factor (Df)

The risk for unintentional release of CO₂ is estimated to be low, and in Alberta, many risk mitigating regulatory processes are in place related to site selection, well drilling and completions, production, operations and abandonment requirements established by the AER. However, some risk remains which may result in the unintentional release of sequestered CO₂ either during the emission offset project or in the future. A discount factor of 0.005 is applied as a conservative approach to manage uncertainty associated with unintentional releases of CO₂. This discount is applied to the projection-based baseline and considered ‘retired to the atmosphere’.

1.5.2. Holdback Factor (Hf)

The risk of intentional releases of CO₂ is mitigated by applying a holdback factor. The project developer must transparently calculate the holdback and include the quantification in each offset project report. The holdback factor is a percentage based on the type of CO₂-EOR scheme approval. The holdback factor for Type 1 EOR schemes is different than the holdback factor for Type 2 EOR schemes (see Section 4.2). Holdback factors are described in section 4 and are applied to the projection-based baseline. The calculated holdback is not serialized at the time of reporting. Project developers can request a release of holdback amounts and if approved, the holdback amount can be serialized after the end of the EOR activity and receipt of the related reclamation certificate. In a case where permanence cannot be verified, all holdback accumulated for an emission offset project will expire and be considered ‘retired to the atmosphere’.

1.5.3. Holdback Release Process

A request for release of holdback must be submitted to the Director, with the required documents and conditions that must be met at the time of request for holdback release.

The project developer must submit a verified post project report that includes:

- The quantified amount of CO₂ that was released to the atmosphere from the EOR Scheme since the end of offset crediting period,
- The quantified amount of new CO₂ that was recently captured and not previously injected and produced from an EOR reservoir, and that was injected into the scheme since the end of the crediting period or last emission offset project report, whichever was most recent,
- Evidence to show that produced CO₂ was recycled, re-injected and not released to atmosphere or moved outside the EOR scheme boundary,

The evidence for CO₂ remaining and CO₂ releases which may consist of:

- historic annual progress report submitted to the AER as required,
- produced volumes reported, and
- previous offset project reports which must document all releases, that may have happened during the crediting period, were accounted for, and
- A summary of the verified holdback amounts from each project report, by vintage year, during the crediting period and any extension, and of the quantified amount of CO₂ that was transferred out of the project boundary since the end of the offset crediting period and where it was transferred. The Report Balance Sheet for CO₂ is in Appendix C.

The project developer must also provide the Director with:

- evidence of ownership of the project,
- any Operational Containment Assurance report, or other containment evidence that was submitted to the AER, and
- evidence the EOR scheme approval has been rescinded, and
- evidence that all project wells associated with the project have been abandoned, and
- a reclamation certificate has been obtained from the AER.

If the EOR scheme becomes an opt-in or large emitter under the Regulation, a summary of annual compliance reports can support the above request for release of holdback.
The returned holdback will be serialized as “Net Geological Sequestration at release of holdback” emission offsets. The vintage year of these emission offsets will be set at the year the reclamation certificate was issued by the AER, regardless of the timing of the request for release. The credit expiration period will be based on the vintage year.

1.5.4. Holdback return calculation for emissions offset project

The method used to determine the amount of holdback returned as emission offsets, where:

Net Geological Sequestration at release of holdback = NGS HB Release

Total Cumulative Holdback from project = HB Total

Releases of CO₂ from project post crediting period = Releases post credit

Transfers of CO₂ from project post crediting period = Transfers post credit

Injections of newly captured CO₂ to the EOR scheme during the post crediting period = INJ post credit

NGS HB Release = min(HB Total - Releases post credit - Transfers post credit + INJ post credit, HB Total)

If NGS HB Release is less than zero it will be treated as a project reversal (see Section 1.5 Reversals).

Note that NGS HB Release cannot exceed HB Total from the end of the offset crediting period.
1.5.5. Transfers of CO₂ from an EOR emission offset project

In order to meet the permanence requirements, and generate emission offsets, the geologically sequestered CO₂ must stay in the geologic formation in which it was injected (i.e. within the emission offset project boundary). Accurate accounting of sources and sinks and the holdback are the mechanisms to ensure permanence during the offset crediting period. Accurate accounting in the Containment Assurance Report and the holdback are the mechanisms used to ensure permanence after the end of the offset crediting period. The mechanisms vary depending on whether the EOR scheme is a Type 1 or Type 2 approval.

Transfers of previously injected CO₂ are not eligible for generating emission offsets. Transfers of previously injected CO₂ from a CO₂-EOR emission offset project must be transparently tracked and reported in all project reporting documents to clearly delineate the quantity, where the CO₂ was transferred to and be included in the annual containment assurance report and the report balance sheet for CO₂. The project developer must provide evidence that all CO₂ that has been removed or released, has been or is now accounted for.

Transfers from Type 1 EOR emission offset projects:

- As Type 1 EOR schemes are not required to lower the reservoir pressure at abandonment, any transfers of CO₂ out of the EOR project during either the crediting period or the post crediting period:
  - must be accounted for as a forfeit of the same quantity of holdback (i.e., 1,000 tonnes Holdback forfeited for 1,000 tonness CO₂ transferred), or

If there is insufficient holdback accumulated to forfeit the same quantity as CO₂ transferred, with the remaining holdback in the CO₂-EOR project greater than 2% of cumulative baseline emissions:

- the project proponent must account for the rest of the transferred CO₂ as a project emission (P22). If this results in net positive emissions during a crediting period it will be treated as a reversal.

Transfers from Type 2 EOR emission offset projects:

- As Type 2 EOR schemes are required to lower the reservoir pressure at end of operations or abandonment, there are two scenarios where some amount of CO₂ (and holdback) may be transferred from a Type 2 EOR emission offset project to another EOR emission offset project:
  - A Type 2 EOR emission offset project that is still within its offset crediting period (including extension) may transfer a quantity of CO₂ to another EOR emission offset project and account for it by transferring the equivalent quantity of holdback to the new EOR project, on the condition that the original EOR emission offset project:
    - has sufficient accumulated holdback,
    - the remaining holdback in the transferring project is greater than 2% of cumulative baseline emissions, after the transfer,

Then the transferred CO₂ will not count as a project emission for the EOR emission offset project exporting the CO₂ and

- the transferred CO₂ is removed from the net injection quantity for the reporting period.

This transfer of holdback effectively moves that portion of the holdback from the source project to the receiving project and moves the holdback return further out in time.

A Type 2 EOR emission offset project that is within its crediting period, but has insufficient holdback accumulated to transfer according to scenario 1, must transfer all the allowed holdback and then account for the rest of the transferred CO₂ as a project emission (P22). If this results in net positive emissions during a crediting period it will be treated as a reversal.

After the offset crediting period has ended for a Type 2 EOR emission offset project, the transfer of previously injected CO₂ from an EOR emission offset project to another EOR emission offset project must be counted as a transfer of holdback. If insufficient holdback remains (including 2% of cumulative baseline emissions, after the transfer), it will be considered a reversal and the related emission offsets will be cancelled at the time of the transfer.

The hierarchy used to account for transfers of CO₂ must first be taken from the holdback quantity (Type 1 holdback forfeited, Type 2 transfer holdback), then from the previously credited CO₂ and finally from the non-credited, but injected CO₂ quantities, if any.
1.6. Reversals

A reversal is an accidental or intentional release or removal of previously injected CO$_2$ from the EOR emission offset project boundary (storage complex), during or after the crediting period. A release of CO$_2$ during a crediting period is also called a reversal if there is an insufficient amount of holdback or injected CO$_2$ in the reporting period to cover the released or removed amount of CO$_2$ (i.e. a net reversal).

The assessment of Sources Sinks and Reservoirs (SSR) in this protocol provide required mechanisms to quantify releases and reversals (see Table 6). Appendix B provides a method for accounting for uncertainty arising out of the monitoring and reservoir management plan. Specific events that might result in a reversal include:

- Blowout or well kick;
- Mechanical integrity/ well failure/ integrity of existing wells in the field;
- Migration of CO$_2$ beyond the perimeter of the injection and recovery project site that aligns with the CO$_2$-EOR scheme approval;
- Drilling through CO$_2$ plume to a lower formation;
- Seismic event;
- Subsequent withdrawal of injected CO$_2$ for deployment in other fields/into pipeline (i.e., CO$_2$ transfers under specific conditions);
- Blowdown of injection wells;
- Unplanned/emergency flaring of formation gas; and
- Other acute (non-steady state) venting events.

At the time of any reporting period, quantification, and verification, including for holdback release, the EOR operator/emission offset project developer must provide evidence that the claimed quantity of CO$_2$ was injected and that all produced CO$_2$ was re-injected or appropriately accounted for. This will demonstrate that the claimed quantities of sequestered CO$_2$ remain in long-term containment in the storage complex. Otherwise, it will be taken that there was an emission, from subsurface to atmosphere. In this case, the amount of the emission from subsurface must be quantified via project quantification term P22 using Appendix B as additional documentation requirements.

If there is a net reversal for a reporting period, the emission offset project developer must withdraw (remove) active registered emission offsets that were serialized during any previous project reporting period(s) under an approved offset quantification protocol. This must be documented in the project report and verified.

A reversal that occurs after an emission offset project crediting period, must be reported immediately to the Director and be quantified and verified in the holdback release report.
1.7. Glossary of Terms

Alberta Electricity Grid
A system of conductors through which electrical energy is transmitted and distributed throughout the province. This electricity grid is an interconnected network of high voltage transmission and lower voltage distribution for delivering electricity from suppliers (generators) to consumers across the province.

Alberta Energy Regulator (AER)
The agency of the Government of Alberta that regulates the safe, responsible and efficient development of Alberta’s energy resources (oil, natural gas, oil sands, coal), pipelines and subsurface sequestration activities.

Capture Site
The point in the process where gas containing CO$_2$ that would otherwise be emitted is separated and captured for eventual injection as part of a CO$_2$-EOR scheme.

Containment Assurance
Demonstration that the features and geologic structure of the CO$_2$-EOR activity are adequate to provide safe, long-term containment of CO$_2$, and that the CO$_2$ flood is operated in a way to assure containment of the CO$_2$ in the EOR storage complex. [Source: ISO 27916:2019]

Directive 007
Volumetric and Infrastructure Requirements (February 2016). This directive sets out the Alberta Energy Regulator’s requirements for reporting volumetric data and well status changes using the Canada’s Petroleum Information Network (Petrinex), and it prescribes the manner in which data must be submitted.

Directive 017
Measurement Requirements for Oil and Gas Operations (March 2016). This directive clarifies, consolidates and updates the Alberta Energy Regulator’s requirements for measurement points used for accounting and reporting purposes, as well as those measurement points required for upstream petroleum facilities and some downstream pipeline operations under existing regulations. The directive does not include instructions on how the volumes must be reported to the Alberta Energy Regulator (see Directive 007).

Directive 020
Well Abandonment (March 2016). This directive details the minimum requirements for abandonments, casing removal, zonal abandonments and plug backs as required under Sections 3.013 of the Oil and Gas Conservation Regulations.

Directive 051
Injection and Disposal Wells: Well Classifications, Completion, Logging, and Testing Requirements (March 1994). This directive classifies injection and disposal wells according to the injected or disposed fluid and specifies design, operating, and monitoring requirements for each class of well.

Directive 065
Resources Applications for Oil and Gas Reservoirs (April 2016). This directive details the process to apply to the Alberta Energy Regulator for all necessary approvals to establish the strategy and plan to deplete a hydrocarbon pool or portion of a pool using one resource application.

Directives
Documents setting out new or amended requirements or processes to be implemented and followed by licensees, permittees and other approval holders under the jurisdiction of the Alberta Energy Regulator.

Discount factor (Df)
A set percentage of the projected baseline is deducted from the baseline emissions to account for the risk of the unintentional release of CO$_2$ from the emission offset project, during its operations and in the future. It is calculated separately for transparency and accounting purposes.

Enhanced Oil Recovery
Oil recovery over and above what is obtained using the natural pressure of the reservoir by injecting CO$_2$ and/or water alternating gas. For the purposes of this protocol, CO$_2$ – Enhanced Oil Recovery produces hydrocarbons from a reservoir using the injection of CO$_2$. [adapted from: ISO 27916:2019]
Enhanced Oil Recovery Storage Scheme (Storage Complex)

Storage reservoir, trap, and such additional surrounding geology in the subsurface as defined by the AER Directive 65 scheme approval within which injected CO\(_2\) will remain in safe, long-term containment. Includes the subsurface geological system extending vertically to comprise the geological stratum (or strata) into which CO\(_2\) is injected for the purpose of storage and identified seal(s) and extending laterally to the defined limits of the CO\(_2\) storage project boundary. [adapted from: ISO 27916:2019]

Higher Heating Value (HHV)

The amount of heat released during the combustion of a fuel and includes the heat in the water component product of combustion. Use of HHV assumes that heat above 150°C can be utilized.

Holdback Factor (H)

A set percentage of the projected baseline emissions is deducted and held back from the baseline emissions to account for possible intentional or operator caused reversals from the project during its lifetime. The net holdback will be released or considered sequestered after specific conditions (i.e., application with evidence of well abandonments, reclamation certificate and true up for any reversals) have been provided by the EOR emission offset project developer. The holdback percentage is based on the type of CO\(_2\)-EOR scheme approval.

Incremental, Directly Connected Electricity

Electricity sourced for the project, from a site that is not a large emitter or opted-in facility that meets the following three criteria:

- Direct Connection: the source of electricity is directly connected to the site or connected through a recognized Industrial System Designation (ISD) that is separate from the provincial electricity grid; and
- Dedicated Electricity Contract: the electricity is sourced using a dedicated electricity purchase agreement; and
- Incremental Generation under contract: the electricity used in the project represents incremental, and under contract, electricity generation that was not previously utilized. This may include either newly installed generation capacity or capacity that has not been utilized in the average year, over the three year baseline period prior to and ending within 6 months of the initiation of the project. It is determined as: the quantity of generated electricity in the offset reporting period beyond average generation in the three baseline years or generation from new capacity installed.

Industrial System Designation

A designation granted by the Alberta Utilities Commission to describe a regional integrated electric system. The system includes: 1) one or more generating units, located on the property of the industrial operations it is intended to serve; 2) one or more industrial operations that are serviced by the generating unit(s); and, 3) a high degree of integration of the electric system with the industrial operations. There is common ownership and management of the components of the system.

Injected Fluid

The total quantity of new CO\(_2\) rich fluid that is measured directly upstream of the CO\(_2\)-EOR scheme or at each wellhead. Injected fluid does not include any quantity of reinjected CO\(_2\) (i.e. recycled CO\(_2\)). Injected fluid is measured in the project condition upstream of the re-injection stream.

Injection Meter

Meter used for quantifying injected CO\(_2\). This is expected to be a custody transfer meter as close as possible to the injection field and wells.

Large Emitter

A facility subject to Alberta’s provincial greenhouse gas Regulation, as the annual GHG emissions exceed the 100,000 tonne CO\(_2\)e threshold. The emissions are fully accounted for and verified.

Monitoring, Measurement and Verification (MMV)

Monitoring and measurement are surveillance activities for ensuring safe and reliable operation of a carbon storage project. Verification, in relation to the monitoring and measurement of CO\(_2\) containment, refers to the comparison of measured and predicted performance. MMV is not required by this emission protocol.
offset protocol. MMV may or may not be required by the AER scheme approval.

New CO$_2$ Anthropogenic CO$_2$ recently captured and not previously injected into a reservoir and recycled.

Opt-In Facility A facility that met the requirements and applied to be regulated under the provincial greenhouse gas Regulation.

Permanent Storage/Net Geological Sequestration The isolation of CO$_2$ in subsurface formations. Injected CO$_2$ is trapped within pore spaces, dissolved in formation fluids and (over long time periods) mineralized.

Process Element Components of the baseline or project that illustrate the flow of CO$_2$ but are not the sources or sinks included in the quantification of baseline and project emissions.

Project Reservoir Geologic reservoir into which CO$_2$ is injected for production of hydrocarbons in paying or commercial quantities. [Source: ISO 27916:2019] Also called storage complex in this protocol.

GHG Reservoir Component, other than the atmosphere, that has the capacity to accumulate greenhouse gases, and to store and release them. [Source: ISO 14064-2:2019]

GHG Sink Process that removes a greenhouse gas from the atmosphere. [Source: ISO 14064-2:2019]

GHG Source Process that releases a greenhouse gas into the atmosphere [Source: ISO 14064-2:2019]

Steam Methane Reforming The most common process by which hydrogen is produced. Heated methane and steam are brought into contact with a catalyst, which produces H$_2$, CO$_2$, CO, and other trace compounds. The CO stream is further reacted with steam in a shift reactor to produce H$_2$ and CO$_2$. The CO$_2$ and H$_2$ are then separated using pressure swing adsorption units, membranes or absorption columns to generate pure hydrogen.

Trap Any feature or mechanism that alone or in combination provides a low-permeability confining geologic layer (cap rock or seal). This includes mechanisms for storage in the pore spaces of the EOR complex (physical, stratigraphic, or structural trapping), by capillary pressure from the water in the pore spaces between the rock (residual trapping), by dissolution in the in situ formation fluids (solubility), by hydrodynamic trapping, by adsorption onto organic matter or by reacting in geologic formations to produce minerals (geochemical trapping). [adapted from ISO 14064-2:2019]

Type 1 CO$_2$-EOR Scheme Where the AER scheme approval does not require lowering the reservoir pressure at abandonment below the reservoir pressure at the end of production operations.

Type 2 CO$_2$-EOR Scheme Where the AER scheme approval requires lowering reservoir pressure at abandonment below the pressure at the end of production operations.

Well Blowout An unintended flow of wellbore fluids (oil, gas, water or other substance) at surface that cannot be controlled by existing wellhead and/or blowout prevention equipment; or a flow from one pool to another pool(s) that cannot be controlled by increasing the fluid density(underground blowout), as defined by the Alberta Energy Regulator Directive 059.

Well Kick Any unexpected entry of water, gas, oil or other formation fluid into a wellbore that is under control and can be circulated out, as defined by the Alberta Energy Regulator Directive 059.
2. Baseline Condition

The baseline scenario for this activity is non CO₂-enhanced oil recovery and emitted CO₂ from a large emitter. The operation during the baseline is assumed to be enhanced oil recovery, without the use of CO₂. Thus, the oil produced from a CO₂-EOR project can be assumed to be unchanged. The oil production is not an additional activity and does not factor into the calculation of sequestered CO₂. The emissions associated with oil production are considered equivalent in the baseline and the project condition so are excluded from the protocol. The baseline for this protocol is dynamic projection-based. Therefore, during the project, the total quantity of CO₂ measured directly upstream of the injection wellheads is projected to the baseline condition. This does not include the quantity of any reinjected CO₂ (i.e. recycled CO₂) or previously credited CO₂.

This projected baseline ensures the baseline correctly accounts for the year to year variation in CO₂ that is captured and injected in the project, and is therefore dynamic. Any CO₂ produced with the oil must be re-injected or accounted for as an emission or transfer if it leaves the offset project boundary. The baseline condition is presented in detail in Figure 1, with the relevant GHG sources, sinks and reservoirs (SSRs) and the EOR process flow diagram. Descriptions of each of the SSRs is provided below.

2.1. Identification of Baseline Sources, Sinks, and Reservoirs (SSRs)

The identification of sources, sinks and reservoirs in the baseline condition is based on ISO 14064-2: Specification with guidance at the project level for quantification, monitoring and reporting of greenhouse gas emission reductions or removal enhancements Standard. SSRs are determined to be either controlled, related or affected by the project activity and are defined as follows:

Controlled: The behaviour or operation of a controlled source and/or sink is under the direction and influence of an emission offset project developer through financial, policy, management or other instruments.

Related: A related source and/or sink has material and/or energy flows into, out of or within a project but is not under the reasonable control of the emission offset project developer.

Affected: An affected source and/or sink is influenced by the project activity through changes in market demand or supply for products or services associated with the project.

All sources, sinks and reservoirs were identified by reviewing the relevant process flow diagrams, consulting with technical experts and reviewing best practice guidance. This iterative process confirmed that SSRs in the process flow diagrams covered the full scope of activities under this protocol.

Based on the process flow diagram provided in Figure 1, the baseline SSRs were organized into life cycle categories and depicted in Figure 2. A description of each SSR and its classification as controlled, related or affected is provided in Table 1 and a description of each source sink is included in Table 2.
Figure 1: Baseline Process Flow Diagram
### Table 1. Baseline Process Elements

<table>
<thead>
<tr>
<th>Process Elements</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy and Material Inputs to Gas Source</td>
<td>Energy and material inputs to the gas source may include electricity, heat and fuel, which may be supplied from on-site or off-site sources.</td>
</tr>
<tr>
<td>CO₂ Source(s)</td>
<td>The CO₂ source includes any type of process that generates CO₂-rich fluid, such as steam methane reforming from a GHG regulated facility in Alberta.</td>
</tr>
<tr>
<td>Capture and Processing</td>
<td>The CO₂-rich stream coming from the CO₂ source may need further purifying and processing before it can be injected. The capture technology applied at the capture facility may use amine as a solvent to separate CO₂ from other components of the gas source.</td>
</tr>
<tr>
<td>Compression/Dehydration</td>
<td>The CO₂-rich stream is compressed before it can be transported to the CO₂-EOR site. Dehydration may also be required to prevent hydrate formation. This may be achieved through heating or other processes.</td>
</tr>
<tr>
<td>Fluid Transport</td>
<td>The CO₂-rich stream will be transported to the injection site via pipeline, or in some cases, by vehicle. Depending on the length of the pipeline or the location of capture facilities, additional booster compression may be needed.</td>
</tr>
<tr>
<td>Fluid Injection</td>
<td>The CO₂-rich stream will be injected at the EOR scheme, for example with the water-alternating-gas method. In certain cases, additional energy inputs may be required at the injection wells for the injection operation or to operate monitoring equipment.</td>
</tr>
<tr>
<td>Re-injected/Recycled Fluid</td>
<td>Any injected fluid that comes back to surface as solution gas is recovered and re-injected (recycled), and additional compression may be required.</td>
</tr>
<tr>
<td>Storage in EOR Scheme</td>
<td>The CO₂-rich stream will be injected into one or more project reservoirs that are suitable and approved by AER for permanent storage via EOR.</td>
</tr>
</tbody>
</table>

**NOTE:** Process elements are included for illustrative purposes only.
Figure 2: Baseline Condition SSRs

**Upstream Sources, Sinks and Reservoirs Baseline**

- B6 Production and Delivery of Materials Used in CO₂ Capture Processes
- B8 Fuel Extraction/Processing
- B9 Fuel Delivery
- B10 Off-Site Electricity Generation
- B11 Off-Site Heat Generation

**Upstream Sources, Sinks and Reservoirs Before Baseline**

- B5 Production and Delivery of Materials Used for Construction of EOR Facilities, Capture Facilities and Transport Facilities
- B7 Construction of EOR Facilities and Well Drill and Service
- B24 Land Clearance and Soil Carbon Loss From Construction of EOR Facilities

**On-Site Sources, Sinks and Reservoirs During Baseline**

- B1* Injected CO₂
- B2 Injected CH₄
- B3 Injected N₂O
- B4 Re-injected Gas
- B12 On-Site Electricity Generation
- B13 Fuel Consumption
- B14 Venting at Capture Site
- B15 Fugitive Emissions at Capture Site
- B16 Venting at Compression / Dehydration
- B17 Fugitives at Compression / Dehydration
- B18 Venting during Transport
- B19 Fugitive Emissions during Transport
- B20 Venting at Injection and Production Wells and in Recycle Stream
- B21 Fugitives at Injection, Recycle and Production Well Sites
- B26 Flare at Injection/Production Wells and Recycle
- B22 Emissions from Subsurface to Atmosphere

**On-site Sources, Sinks and Reservoirs After Baseline**

- B23 Decommissioning of EOR Facilities

**Downstream Sources, Sinks and Reservoirs During Baseline**

- B25 Loss, Disposal or Recycling of Materials Used in CO₂ Capture Processes

**Legend**

- Related Source/Sink
- Controlled Source/Sink
- Affected Source/Sink

*Indicates included in baseline case quantification. All Other Sources, Sinks and Reservoirs excluded. See Table 5 for Justification*
### Table 2. Identification of Baseline Sources, Sinks and Reservoirs (SSRs)

<table>
<thead>
<tr>
<th>Source, Sinks and Reservoirs (SSRs)</th>
<th>Description</th>
<th>Controlled, Related or Affected</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Upstream SSRs During Baseline</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>B6 Production and Delivery of Materials used in CO₂ Capture Process</td>
<td>Material inputs for CO₂ capture and processing are required. These inputs may be specialized chemicals or additives such as amines. Greenhouse gas emissions are attributed to the fossil fuel consumption for transport of these materials, and the electricity and fossil fuel inputs for their production. The total aggregate quantity of each chemical delivered to the site must be tracked.</td>
<td>Affected</td>
</tr>
<tr>
<td>B8 Fuel Extraction/Processing</td>
<td>Each of the fuels used throughout the project will need to be sourced and processed. This will allow for the calculation of the greenhouse gas emissions from the various processes involved in the production, refinement and storage of the fuels. The total volumes of fuel, for each of the SSRs, are considered under this SSR. Volumes and types of fuels used throughout the project are the important characteristics to be tracked.</td>
<td>Related</td>
</tr>
<tr>
<td>B9 Fuel Delivery</td>
<td>Each of the fuels used throughout the project will need to be transported to the site. This may include shipments by tanker or by pipeline, resulting in the emissions of greenhouse gases. It is reasonable to exclude fuel sourced by taking equipment to an existing commercial fueling station as the fuel used to take the equipment to the site is captured under other SSRs and there is no other delivery.</td>
<td>Related</td>
</tr>
<tr>
<td>B10 Off-site Electricity Generation</td>
<td>The total quantity of electricity used by the capture facilities, along the transportation network and at the enhanced oil recovery injection and recycle facilities must be tracked for related greenhouse gas emissions. All sources of off-site electricity delivered to the project site must be able to be separated in order to quantify electricity from each incremental directly connected source and from electricity sourced from the electricity grid. The sources of off-site electricity can include: Grid Electricity: All sources of electricity delivered by the provincial grid must apply the appropriate grid intensity factor published by Alberta Environment and Parks. Incremental, Directly Connected Electricity Generation through Industrial System Designation: Off-site electricity that is not being sourced from the grid and meets the definition of Incremental, Directly Connected Electricity will have different emission intensity factors depending on the following categories: o Electricity from a regulated large emitter; o Electricity from an offset project; or o Electricity from a non-regulated entity, non-offset project.</td>
<td>Related</td>
</tr>
<tr>
<td>B11 Off-Site Heat Generation</td>
<td>Emissions associated with generation of thermal energy off site. Off-site heat delivered to the emission offset project may have been generated independently or via cogeneration. The quantity and type of fuels consumed to generate heat must be tracked. The sources of off-site heat will have different emission intensity factors and can include: Industrial heat from a regulated large emitter; or Heat from a non-regulated entity.</td>
<td>Related</td>
</tr>
<tr>
<td><strong>Upstream SSRs Before Baseline</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>B5 Production and Delivery of Materials Used for Construction of EOR Facilities, Capture Facilities and Transport Facilities</td>
<td>Materials used in the construction of carbon capture, transportation and EOR facilities such as steel and concrete will need to be manufactured and delivered to the site. Emissions are attributed to fossil fuel and electricity consumption for material manufacture and fossil fuel consumption for material delivery.</td>
<td>Affected</td>
</tr>
<tr>
<td>B7 Construction of EOR Facilities and Well Drilling</td>
<td>Site construction will require a variety of heavy equipment, smaller power tools, cranes, generators and well drilling operations. The operation of this equipment will have associated greenhouse gas emission from the use of fossil fuels and electricity and from the potential kick or blowout event that could release hydrocarbons during the drilling of injection, production and monitoring wells.</td>
<td>Affected</td>
</tr>
<tr>
<td>Source, Sinks and Reservoirs (SSRs)</td>
<td>Description</td>
<td>Controlled, Related or Affected</td>
</tr>
<tr>
<td>------------------------------------</td>
<td>-------------</td>
<td>-------------------------------</td>
</tr>
<tr>
<td>B24 Land Clearing and Soil Carbon Loss from Construction of Enhanced Oil Recovery Facilities</td>
<td>The clearing of vegetated or forested land for site preparation may release CO₂ from the soil into the atmosphere that was previously stored in soil.</td>
<td>Affected</td>
</tr>
<tr>
<td><strong>On-Site SSRs During Baseline</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>B1 Injected CO₂</td>
<td>All CO₂ emissions released to the atmosphere in baseline as waste CO₂. Baseline emissions are projected back, using the direct measurement of the quantity of fluid that is measured upstream of the injection wellheads in the project condition. Excludes reinjected fluid.</td>
<td>Controlled</td>
</tr>
<tr>
<td>B2 Injected CH₄</td>
<td>All CH₄ emissions released to the atmosphere in baseline, as projected back from the project condition. Baseline emissions are projected back, using direct measurement of the quantity of fluid that has been measured upstream of the injection wellheads in the project condition.</td>
<td>Controlled</td>
</tr>
<tr>
<td>B3 Injected N₂O</td>
<td>All N₂O emissions released to the atmosphere in baseline, as projected back from the project condition. Baseline emissions are projected back, using direct measurement of the quantity of fluid that has been measured upstream of the injection wellheads in the project condition.</td>
<td>Controlled</td>
</tr>
<tr>
<td>B4 Re-Injected Fluid</td>
<td>All CO₂ that is produced and re-injected at the EOR scheme must be accounted for and these quantities must be differentiated from B1 Injected CO₂. In some cases, this reinjected fluid is CO₂ that had been previously injected, but in other cases, the re-injected CO₂ was derived from carbonate materials in the project reservoir (i.e., formation CO₂).</td>
<td>Controlled</td>
</tr>
<tr>
<td>B12 On-Site Electricity Generation</td>
<td>Electricity inputs may be required for CO₂ capture, compression, transportation, injection and re-injection. Electricity may be generated independently or from cogeneration within the project boundary. The quantity and type of fuels consumed to generate electricity, and the quantity of electricity consumed by the project from each generating source must be tracked.</td>
<td>Controlled</td>
</tr>
<tr>
<td>B13 Fuel Consumption</td>
<td>Fuel may be consumed for CO₂ capture, compression, transportation, injection and re-injected. The quantity and type of fuels consumed by the project from each emitting source must be tracked.</td>
<td>Controlled</td>
</tr>
<tr>
<td>B14 Venting at Capture Site</td>
<td>Some gases may be vented from the CO₂ capture facilities during the project condition. CO₂ venting may also be necessary for equipment maintenance or emergency shutdowns. These gases will be composed primarily of CO₂ with trace amounts of other gases.</td>
<td>Controlled</td>
</tr>
<tr>
<td>B15 Fugitive Emissions at Capture Site</td>
<td>Unintended leaks of gas from the CO₂ capture, measurement and processing unit may occur through faulty seals, loose fittings, or equipment.</td>
<td>Related</td>
</tr>
<tr>
<td>B16 Venting during Compression/Dehydration</td>
<td>Planned and emergency venting may be necessary for compressor and dehydrator maintenance and/or emergency shutdowns.</td>
<td>Controlled</td>
</tr>
<tr>
<td>B17 Fugitive Emissions during Compression/Dehydration</td>
<td>Unintended leaks of gas from the compressor and/or dehydrator may occur through seals, loose fittings, equipment, or compressor packing.</td>
<td>Related</td>
</tr>
<tr>
<td>Source, Sinks and Reservoirs (SSRs)</td>
<td>Description</td>
<td>Controlled, Related or Affected</td>
</tr>
<tr>
<td>-----------------------------------</td>
<td>-------------</td>
<td>---------------------------------</td>
</tr>
<tr>
<td><strong>B18 Venting during Transport</strong></td>
<td>Planned and emergency venting may be necessary for pipeline maintenance and/or shutdowns.</td>
<td>Controlled</td>
</tr>
<tr>
<td><strong>B19 Fugitive Emissions during Transport</strong></td>
<td>Unintended leaks of gas from the CO₂ pipeline, transportation equipment, and additional compressors may occur through seals, loose fittings, equipment, or compressor packing.</td>
<td>Related</td>
</tr>
<tr>
<td><strong>B20 Venting at Injection/ Production Wells and Recycle</strong></td>
<td>Planned and emergency venting may be necessary for injection, production or re-injection well work overs, mechanical integrity checks, and maintenance. Instances of venting must be logged, including the duration of the venting event and the estimated volumes vented.</td>
<td>Controlled</td>
</tr>
<tr>
<td><strong>B21 Fugitive Emissions at Injection/Recycle and Production Well</strong></td>
<td>Unintended leaks of gas at the CO₂ injection wells, re-injection wells or production wells may occur through valves, flanges, piping, pipe connections, mechanical seals, or related equipment.</td>
<td>Related</td>
</tr>
<tr>
<td><strong>B26 Flare at Injection/Production Wells and Recycle</strong></td>
<td>Planned and emergency flaring may be necessary for injection, production or re-injection well work overs, mechanical integrity checks, and maintenance. Instances of flaring must be logged, including the duration of the flaring event, sources of gases flared including any additional natural gas makeup and the estimated quantities flared.</td>
<td>Controlled</td>
</tr>
</tbody>
</table>

**On-Site SSRs After Baseline**

| **B22 Emissions from Subsurface to Atmosphere** | Unintended or unplanned release to the atmosphere may occur from gas migration through undetected faults, fractures and/or subsurface equipment resulting from compromised casing/cement/wellhead or packer/tubing. CO₂ that migrates from the intended storage complex but remain subsurface are considered the same as if they had leaked to the atmosphere and must be quantified accordingly. Intentional releases or removals/transfers of CO₂ (when there is insufficient holdback) or net reversals are included here also | Related |
| **B23 Decommissioning of CO₂ Capture and Enhanced Oil Recovery Facilities** | Infrastructure is decommissioned at the end of project operations. This involves the disassembly of the equipment, demolition of on-site structures, landfill disposal of some materials, environmental restoration, re-grading, planting or seeding, and transportation of materials off-site. Greenhouse gas emissions result from fossil fuels combustion and electricity use. | Related |

**Downstream SSRs During Baseline**

| **B25 Loss, Disposal, or Recycling of Materials Used in CO₂ Capture Processes** | Material inputs are either disposed or re-injection at the end of their useful life. Greenhouse gas emissions result from the transportation of materials to industrial landfill and/or material recycling processes. Emissions are also associated with the loss of material during project operation. | Affected |
3. Project Condition

The CO₂-EOR activity is defined as including three distinct components: the capture and compression of CO₂; the transport of CO₂ to the injection wells; and the metering and injection of CO₂ that results in the permanent geological sequestration of the CO₂ in an approved EOR scheme (i.e. storage complex). Produced CO₂, emerging from the subsurface due to oil production, is typically processed, and reinjected into an EOR scheme (storage complex). No reinjected fluid (i.e. recycled fluid) quantities are eligible for emission offsets under this quantification protocol. The production of oil is also a major component of an EOR scheme. Oil production and the emissions explicitly associated with the oil production are not included in the quantification of the EOR offset project emissions (i.e., emissions from fuel combusted in pumping oil to a flow line, etc.). Emissions from oil production are not incremental to the baseline condition for this activity, which is enhanced oil recovery occurring by a process other than CO₂ injection.

The main process elements of a typical CO₂-EOR activity are described below. CO₂-EOR emission offset projects may employ other capture, transport, injection, production and re-injection approaches and processes. Approval from the Director under the Act will be required for all new projects and for any deviations from this protocol. If the emission offset project scenario changes, for example to include new capture sites, the project developer must notify the Director of the new source of CO₂ and update the offset project plan to document the change in project scenario.

CO₂ Capture and Compression

For this protocol, only new CO₂ (i.e. anthropogenic CO₂ recently captured and not previously injected and produced from an EOR reservoir) reported as exported from a regulated large emitter or opted-in facility that is ultimately captured and used is eligible. CO₂ capture refers to the process of capturing CO₂, and often includes the separation of CO₂ from other gas species generated at the emissions source. All CO₂ capture technologies are eligible under this protocol. The typical CO₂ capture infrastructure consists of the following main process blocks:

- CO₂ capture from existing high purity process streams, e.g., fertilizer plant, gasification; or,
- CO₂ separation. This typically includes amine solvents, absorbers and associated equipment; and/or, solvent regeneration unit(s), which may include the following:
  - Stripper column and associated reboiler, pumps and heat exchangers;
  - Solvent filtration;
  - Solvent storage;
  - CO₂ vent stack; and
- CO₂ compression, which may include a multi-stage compressor with an electrical motor and interstage coolers and knockout drums, CO₂ dehydration and interim CO₂ holding facilities.

GHG emissions associated with capture and compression processes are accounted for in the project condition.

Transport

The transportation system may be a pipeline including booster compression and/or pumps to transport CO₂ from the capture facility to the injection well(s). Alternatively, transportation could be CO₂ moved by vehicle from the capture facility to the injection wells.

Pipeline transportation system infrastructure may include equipment such as electrical or mechanical compressors or pumps, and a pipeline network connecting the capture site to the injection site with line block valves and metering equipment. Supervisory control and data acquisition (SCADA) systems or other systems maybe used to collect, transmit data from the pipeline to a control centre and to monitor line block valves. CO₂ is typically transferred in a dense phase and emissions arising from the inline compression and pumping of CO₂ at the capture site are part of the transport system.
Storage

The CO₂ storage infrastructure may include; injection wells, measurement and gas analysis equipment, and flow lines from the main transportation system to the individual injector wells. Metering of new injected fluid quantities and CO₂ concentration to calculate injected CO₂ quantity takes place as close to the injection point as is reasonable. This must be demonstrated by project schematics. A mass balance approach may be appropriate if project schematics confirms measured parameters for all inputs except for the one variable being solved for. Once injected into the CO₂-EOR scheme (subsurface storage complex), as is defined by the Directive 065 EOR scheme approval issued to the EOR operator by the AER, CO₂ is contained within the pore spaces of the reservoir. Geologic storage, with the exception of adsorption, is most efficient at depths where the formation pressure and temperature are sufficient to cause CO₂ to remain in a dense state. CO₂ is stored by one or more of the following trapping mechanisms¹:
- Structural trapping below an impermeable, confining layer (cap rock);
- Residual trapping (retention as an immobile phase trapped in the pore spaces of the project reservoir);
- Solubility trapping (CO₂ dissolved into the fluids that saturate the pore space within a project reservoir);
- Mineralization trapping (precipitation as a carbonate material); and
- Adsorption onto organic matter in coal and shale (i.e., CO₂ bonds with geologic formation).

All emissions associated with storage operations, including vented and fugitive emissions at the injection site (after the injection meter) and from the subsurface, are accounted for in the project condition and refer to the terms of the Directive 065 approval for compliance.

Re-Injected Fluid

During extraction and production of oil and gas from the EOR scheme, some of the injected CO₂ returns to the surface in a free gas state or mixed with other hydrocarbons as solution gas. Once at the surface, the free CO₂ and the CO₂ in solution gas is separated from the oil and water in the separation process and the gas is re-injected ("recycled") into the storage complex via the injection wells. All CO₂ that returns to the surface as solution gas or as a free gas, which is released to the atmosphere either intentionally or unintentionally, must be accounted for in the emission offset project.

Different phases of development will involve a range of re-injection rates, typically increasing over time, and equipment must be sized appropriately to ensure permanent storage of CO₂. While injection in early years may consist of 100% new CO₂ (as opposed to re-injected CO₂), there will typically be a greater proportion of re-injected fluid in the later years of an EOR emission offset project.

Transferring CO₂ from one storage container to another storage container within the same Type 2 EOR scheme is allowed, on the condition that the emission offset project developer or EOR operator reports this accounting within the annual AER progress report. The offset project report must be clear, and transparently show it is an internal transfer within the scheme approval, and not included in the determination of new CO₂ volumes.

Transferring CO₂ from one Type 2 EOR emission offset project to another EOR emission offset project is also allowed when specific conditions are met (see details in Section 1.4.5). The third party assurance provider must fully review and provide comment on any CO₂ removals or transfers as part of their verification of the Report Balance Sheet for CO₂ (Appendix C).

The concentration of new CO₂ and the quantity injected into the emission offset project must be measured. Only new CO₂ injection is eligible to generate emission offsets. The venting or fugitive emissions from any re-injection (i.e., recycling or transferring) of CO₂ as well as the emissions associated with fuel use and electricity use and must be accounted for as project emissions.

Re-injection infrastructure may include measurement and gas analysis equipment, gas separation equipment, re-injection compression, valves, flow lines and piping.

3.1. Identification of Project GHG Sources, Sinks and Reservoirs (SSRs)

All sources, sinks and reservoirs for the project condition were identified based on a review of existing best practice guidance contained in relevant greenhouse gas quantification protocols and enhanced oil recovery project configurations. The process flow diagram provided in Figure 3 covers the SSRs within the full scope of project activities under this protocol. Process elements are further defined in Table 3. The project SSRs are organized into life cycle categories as shown in Figure 4. These SSRs are defined and classified as controlled, related or affected as described in Table 4.


Classification: Public
Figure 3: Process Flow Diagram for the Project Condition

- P25 Loss, Disposal or Recycling of Materials Used in CO₂ Capture Processes
- P6 Production and Delivery of Materials Used in CO₂ Capture Processes
- P8 Fuel Extraction/Processing
- P9 Fuel Delivery
- P10 Off-Site Electricity Generation
- P11 Off-Site Heat Generation
- P12 On-Site Electricity Generation
- P13 Fuel Consumption
- Gas Capture and Processing
- Gas Compression/Dehydration
- Gas Transport
- Gas Injection at Well Sites
- Gas Storage in EOR Scheme
- Energy and Material Inputs to Source
- Gas Source(s)

- P14 Venting at Capture Site
- P15 Fugitives at Capture Site
- P16 Venting at Compression/Dehydration
- P17 Fugitives at Compression/Dehydration
- P18 Venting During Transport
- P19 Fugitives During Transport
- P20 Venting at Injection and Production Well and in Recycle Stream
- P21 Fugitives at Injection, Recycle and Production Well Sites
- P22 Emissions from Subsurface to Atmosphere
- P23 Decommissioning of EOR Facilities
- P24 Land Clearance and Soil Carbon Loss from Construction of EOR Facilities and Transport Facilities
- P25 Construction of EOR Facilities and Well Drilling

Indicates Project Boundary
### Table 3: Project Process Elements

<table>
<thead>
<tr>
<th>Process Elements</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy and Material Inputs to Gas Source</td>
<td>Energy and material inputs to the gas source may include electricity, heat and fuel, which may be supplied from on-site or off-site sources.</td>
</tr>
<tr>
<td>CO₂ Source(s)</td>
<td>The source includes any type of process that generates CO₂-rich fluid, such as steam methane reforming from a GHG regulated facility in Alberta.</td>
</tr>
<tr>
<td>Capture and Processing</td>
<td>The CO₂-rich stream coming from the gas source may need further purifying and processing before it can be injected. The capture technology applied at the capture facility may use amine as a solvent to separate CO₂ from other components of the gas source.</td>
</tr>
<tr>
<td>Compression/Dehydration</td>
<td>The CO₂-rich stream is compressed before it can be transported to the CO₂-EOR scheme. Dehydration may also be required to prevent hydrate formation. This may be achieved through heating or other processes.</td>
</tr>
<tr>
<td>Transport</td>
<td>The CO₂-rich stream will be transported to the injection site via pipeline, or CO₂ could be delivered by vehicle. Depending on the length of the pipeline or the location of capture facilities, additional booster compression may be needed.</td>
</tr>
<tr>
<td>Injection</td>
<td>The CO₂-rich stream will be injected at the EOR scheme, for example with the water-alternating-gas method. In certain cases, additional energy inputs may be required at the injection wells for the injection operation or to operate monitoring equipment.</td>
</tr>
<tr>
<td>Re-injected/ Recycled Fluid</td>
<td>Any injected fluid that comes back to surface as solution gas or free gas is recovered and re-injected (recycled), and additional compression may be required.</td>
</tr>
<tr>
<td>Gas Storage in EOR Scheme</td>
<td>The CO₂-rich stream will be injected in one or more project reservoirs suitable for permanent storage via EOR.</td>
</tr>
</tbody>
</table>

**NOTE:** Process elements are included for illustrative purposes only.
Figure 4: Project Condition SSRs

Upstream Sources, Sinks and Reservoirs During Project

- **P6**: Production and Delivery of Materials Used in CO₂ Capture Processes
- **P8**: Fuel Extraction/Processing
- **P9**: Fuel Delivery
- **P10**: Off-Site Electricity Generation
- **P11**: Off-Site Heat Generation

Upstream Sources, Sinks and Reservoirs Before Project

- **P5**: Production and Delivery of Materials Used for Construction of EOR Facilities, Capture Facilities and Transport Facilities
- **P7**: Construction of EOR Facilities and Well Drill and Service
- **P24**: Land Clearance and Soil Carbon Loss From Construction of EOR Facilities

On-Site Sources, Sinks and Reservoirs During Project

- **P12**: On-Site Electricity Generation
- **P13**: Fuel Consumption
- **P14**: Venting at Capture Site
- **P15**: Fugitive Emissions at Capture Site
- **P16**: Venting at Compression / Dehydration
- **P17**: Fugitives at Compression / Dehydration
- **P18**: Venting during Transport
- **P19**: Fugitive Emissions during Transport
- **P20**: Venting at Injection and Production Wells and in Recycle Stream
- **P21**: Fugitives at Injection / Production Wells and Recycle
- **P22**: Emissions from Subsurface to Atmosphere
- **P23**: Decommissioning of EOR Facilities
- **P24**:Injected CO₂
- **P25**: Injected CH₄
- **P3**: Injected N₂O
- **P4**: Re-injected Gas

Downstream Sources, Sinks and Reservoirs During Project

- **P25**: Loss, Disposal or Recycling of Materials Used in CO₂ Capture Processes

Legend

* Indicates included in project case quantification. All Other Sources, Sinks and Reservoirs excluded. See Table 3 for justification

Related Source/Sink
Controlled Source/Sink
Affected Source/Sink
### Table 4: Identification of Project Sources, Sinks and Reservoirs (SSR)

<table>
<thead>
<tr>
<th>Source, Sinks and Reservoirs (SSRs)</th>
<th>Description</th>
<th>Controlled, Related or Affected</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Upstream SSRs During Project Condition</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>P6 Production and Delivery of Material Inputs used in CO₂ Capture Process</td>
<td>Material inputs for CO₂ capture and processing are required. These inputs may be specialized chemicals or additives such as amines. Greenhouse gas emissions are attributed to the fossil fuel consumption for transport of these materials, and the electricity and fossil fuel inputs for their production. The total aggregate quantity of each chemical delivered would be tracked.</td>
<td>Related</td>
</tr>
<tr>
<td>P8 Fuel Extraction/Processing</td>
<td>Each of the fuels used throughout the project will need to be sourced and processed. This will allow for the calculation of the greenhouse gas emissions from the various processes involved in the production, refinement and storage of the fuels. The total volumes of fuel for each of the SSRs are considered under this SSR. Volumes and types of fuels are the important characteristics to be tracked.</td>
<td>Related</td>
</tr>
<tr>
<td>P9 Fuel Delivery</td>
<td>Each of the fuels used throughout the project will need to be transported to the site. This may include shipments by tanker or by pipeline, resulting in the emissions of greenhouse gases. It is reasonable to exclude fuel sourced by taking equipment to an existing commercial fueling station as the fuel used to take the equipment to the sites is captured under other SSRs and there is no other delivery.</td>
<td>Related</td>
</tr>
<tr>
<td>P10 Off-site Electricity Generation</td>
<td>The total quantities of electricity used and electricity imported by the capture facilities, the transport facility and the enhanced oil recovery injection and re-injection facilities must be tracked to estimate related greenhouse gas emissions. All sources of off-site electricity delivered to the project site must be able to be separated in order to quantify electricity from each incremental directly connected source and from electricity sourced from the electricity grid. The sources of off-site electricity may include: Grid Electricity: All sources of electricity delivered by the provincial grid must apply the appropriate grid intensity factor published by Alberta Environment and Parks. Incremental, Directly Connected Electricity Generation through Industrial System Designation: Off-site electricity that is not being sourced from the grid and meets the definition of Incremental, Directly Connected Electricity will have different emission intensity factors depending on the following categories: o Electricity from a large emitter; o Electricity from an offset project; or o Electricity from a non-regulated entity, non-offset project.</td>
<td>Related</td>
</tr>
<tr>
<td>P11 Off-site Heat Generation</td>
<td>Emissions associated with generation of thermal energy off site. Off-site heat delivered to the emission offset project may have been generated independently. The sources of off-site heat will have different emission intensity factors and can include: o Industrial heat from a regulated large emitter; or o Heat from a non-regulated entity or o Offset project.</td>
<td>Related</td>
</tr>
<tr>
<td><strong>Upstream SSRs Before Project Condition</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>P5 Production and Delivery of Materials Used for Construction of EOR Facilities, Capture Facilities and Transport Facilities</td>
<td>Materials used in the construction of carbon capture, transport and EOR facilities such as steel and concrete will need to be manufactured and delivered to the site. Emissions are attributed to fossil fuel and electricity consumption for material manufacture and fossil fuel consumption for material delivery.</td>
<td>Related</td>
</tr>
<tr>
<td>Source, Sinks and Reservoirs (SSRs)</td>
<td>Description</td>
<td>Controlled, Related or Affected</td>
</tr>
<tr>
<td>------------------------------------------------------------------------------------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
<td>--------------------------------</td>
</tr>
<tr>
<td>P7 Construction of EOR Facilities and Well Drill and Service</td>
<td>Site construction will require a variety of heavy equipment, smaller power tools, cranes, generators and well drilling operations. The operation of this equipment will have associated greenhouse gas emission from the use of fossil fuels and electricity and from the potential kick or blowout event that could release hydrocarbons during the drilling of injection and monitoring wells.</td>
<td>Related</td>
</tr>
<tr>
<td>P24 Land Clearing and Soil Carbon Loss from Construction of Enhanced Oil Recovery Facilities</td>
<td>The clearing of vegetative or forested land for site preparation may cause soil to release CO(_2) into the atmosphere that was previously stored in soil.</td>
<td>Related</td>
</tr>
</tbody>
</table>

**On-Site SSRs During Project Condition**

<p>| P1 Injected CO(_2)                                                                 | The quantity of new CO(_2) injected in the project and not released. This quantity is projected back to the baseline, from the project condition as CO(_2) emissions released to the atmosphere, from the large emitter facility. The quantity of fluid is directly measured upstream of the injection wellheads and upstream of any re-injected (recycled) gas. | Controlled                     |
| P2 Injected CH(_4)                                                               | All CH(_4) emissions released to the atmosphere in baseline, as projected from the project condition. Only baseline CO(_2) emissions are projected, using direct measurement of the quantity of gas that is measured upstream of the injection wellheads in the project condition and upstream of re-injected (recycled) gas. | Controlled                     |
| P3 Injected N(_2)O                                                               | All N(_2)O emissions released to the atmosphere in baseline, as projected from the project condition. Only baseline CO(_2) emissions are projected, using direct measurement of the quantity of gas that is measured upstream of the injection wellheads in the project condition and upstream of re-injected (recycled) gas. | Controlled                     |
| P4 Re-Injected (Recycled) Gas                                                      | All CO(_2) that is produced from the EOR scheme and re-injected (recycled).                                                                                                                                | Controlled                     |
| P12 On-Site Electricity Generation                                                 | Electricity inputs may be required for CO(_2) capture, compression, transportation, injection and re-injection. Electricity may be generated independently or from generation within the project boundary. The quantity and type of fuels consumed to generate electricity, and the quantity of electricity consumed by the project from each generating source would be tracked. | Controlled                     |
| P13 Fuel Consumption                                                              | Fuel use may be required for CO(_2) capture, processing, compression, dehydration, transportation, injection and re-injection or for heat or electricity generation. The quantity and type of fuels consumed from each source would be tracked. | Controlled                     |
| P14 Venting at Capture Site                                                       | Some gases may be vented from the CO(_2) capture facilities during the project condition or during post offset project operations. CO(_2) venting may also be necessary for equipment maintenance or emergency shutdowns. These gases will be composed primarily of CO(_2) with trace amounts of other gases. | Controlled                     |</p>
<table>
<thead>
<tr>
<th>Source, Sinks and Reservoirs (SSRs)</th>
<th>Description</th>
<th>Controlled, Related or Affected</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>P15 Fugitive Emissions at Capture Site</strong></td>
<td>Unintended leaks of gas from the CO₂ capture, measurement and processing unit may occur through faulty seals, loose fittings, or equipment.</td>
<td>Related</td>
</tr>
<tr>
<td><strong>P16 Venting at Compression/Dehydration</strong></td>
<td>Planned and emergency venting may be necessary for compressor and dehydrator maintenance and/or emergency shutdowns.</td>
<td>Controlled</td>
</tr>
<tr>
<td><strong>P17 Fugitive Emissions at Compression/Dehydration</strong></td>
<td>Unintended leaks of gas from the compressor and/or dehydrator may occur through seals, loose fittings, equipment, or compressor packing.</td>
<td>Related</td>
</tr>
<tr>
<td><strong>P18 Venting during Transportation</strong></td>
<td>Planned and emergency venting may be necessary for pipeline maintenance and/or shutdowns.</td>
<td>Controlled</td>
</tr>
<tr>
<td><strong>P19 Fugitive Emissions during Transportation</strong></td>
<td>Unintended leaks of gas from the CO₂ pipeline, transportation equipment, and additional compressors may occur through seals, loose fittings, equipment, or compressor packing. Include emissions from additional compression here only if they can’t be separated out and accounted for under P15.</td>
<td>Related</td>
</tr>
<tr>
<td><strong>P20 Venting at Injection and Production Wells and in Recycle Stream</strong></td>
<td>Planned and emergency venting may be necessary for injection or production well work overs, in the handling of the recycle gas stream, for mechanical integrity checks, and maintenance. Instances of venting must be logged, including the duration of the venting event and the estimated quantities and makeup of gasses vented.</td>
<td>Controlled</td>
</tr>
<tr>
<td><strong>P21 Fugitive Emissions at Injection, Recycle and Production Wells</strong></td>
<td>Unintended or unplanned leaks of gas at the CO₂ injection wells or production wells and at CO₂ recycle facilities may occur through valves, flanges, piping, pipe connections, mechanical seals, or related equipment.</td>
<td>Related</td>
</tr>
<tr>
<td><strong>P22 Emissions from Subsurface to Atmosphere</strong></td>
<td>Accidental emissions to the atmosphere may occur from gas migration through undetected faults, fractures and/or subsurface equipment resulting from compromised casing, cement, wellhead, packer or tubing. Intentional releases or removals/transfers of CO₂ (when there is insufficient holdback) or net reversals are included here also</td>
<td>Related</td>
</tr>
<tr>
<td><strong>P26 Flare at Injection/Production Wells and Recycle Stream</strong></td>
<td>Planned and emergency flaring may be necessary for injection or production well sites or during work overs, mechanical integrity checks, re-injection stream flaring. These flare volumes and subsequent emissions are additional to baseline condition flaring due to EOR scheme oil production. Instances of project condition flaring is logged, including the duration of the flaring event, and sources of gases flared include any additional natural gas and the estimated quantities flared.</td>
<td>Controlled</td>
</tr>
</tbody>
</table>

**On-Site SSRs After Project**

**P23 Decommissioning of CO₂ Capture and Enhanced Oil Recovery Facilities** | Infrastructure is decommissioned at the end of project operations. This involves the disassembly of the equipment, demolition of on-site structures, landfill disposal of some materials, environmental restoration, re-grading, planting or seeding, and transportation of materials off-site. Greenhouse gas emissions result from fossil fuels combustion and electricity use. | Related |

**Downstream SSRs During Project**
<table>
<thead>
<tr>
<th>Source, Sinks and Reservoirs (SSRs)</th>
<th>Description</th>
<th>Controlled, Related or Affected</th>
</tr>
</thead>
<tbody>
<tr>
<td>P25 Loss, Disposal, or Recycling of Materials Used in CO₂ Capture Processes</td>
<td>Material inputs are either disposed or recycled at the end of their useful life. Greenhouse gas emissions result from the transportation of materials to industrial landfill and/or material recycling processes. Emissions are also associated with the loss of material during project operation.</td>
<td>Related</td>
</tr>
</tbody>
</table>
4. Quantification

Baseline and project conditions were assessed against each other to determine the scope for geological sequestration quantified under this protocol. SSRs are either included or excluded depending on how they are impacted by the project activity. SSRs that are not expected to change between baseline and project condition are excluded from quantification. It is assessed that excluded SSRs will either occur at the same magnitude and emission rate during the baseline and project or are functionally equivalent or are not impacted by the activity.

Emissions that increase or decrease as a result of the project may be included and associated greenhouse gas emissions are therefore quantified as part of the project.

All SSRs are identified in Table 5 as included or excluded and the justification for each of these choices is provided.
Table 5: Comparison of Sources, Sinks and Reservoirs (SSRs)

<table>
<thead>
<tr>
<th>Identified SSRs</th>
<th>Baseline (C,R,A)</th>
<th>Project (C,R,A)</th>
<th>Include or Exclude from Quantification</th>
<th>Justification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Upstream SSRs</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>P6</td>
<td>N/A</td>
<td>Related</td>
<td>Include</td>
<td>This source may have a material impact on project emissions resulting from increased upstream chemical production associated with project period chemical usage.</td>
</tr>
<tr>
<td>B6</td>
<td>Affected</td>
<td>N/A</td>
<td>Exclude</td>
<td>Activity does not occur in the Baseline.</td>
</tr>
<tr>
<td>P8</td>
<td>N/A</td>
<td>Related</td>
<td>Include</td>
<td>This source/sink may have a material impact on project emissions.</td>
</tr>
<tr>
<td>B8</td>
<td>Related</td>
<td>N/A</td>
<td>Exclude</td>
<td>Activity for CO₂-EOR does not occur in the Baseline.</td>
</tr>
<tr>
<td>P9</td>
<td>N/A</td>
<td>Related</td>
<td>Include</td>
<td>This source may have a material impact on project emissions.</td>
</tr>
<tr>
<td>B9</td>
<td>Related</td>
<td>N/A</td>
<td>Exclude</td>
<td>Activity for CO₂-EOR does not occur in the Baseline.</td>
</tr>
<tr>
<td>P10</td>
<td>N/A</td>
<td>Related</td>
<td>Include</td>
<td>This source may have a material impact on project emissions.</td>
</tr>
<tr>
<td>B10</td>
<td>Related</td>
<td>N/A</td>
<td>Exclude</td>
<td>Activity for CO₂-EOR does not occur in the Baseline.</td>
</tr>
<tr>
<td>P11</td>
<td>N/A</td>
<td>Related</td>
<td>Include</td>
<td>This source may have a material impact on project emissions.</td>
</tr>
<tr>
<td>B11</td>
<td>Related</td>
<td>N/A</td>
<td>Exclude</td>
<td>Activity for CO₂-EOR does not occur in the Baseline.</td>
</tr>
<tr>
<td>P5</td>
<td>N/A</td>
<td>Related</td>
<td>Exclude</td>
<td>This one-time only source of greenhouse gas emissions is negligible compared to the expected size and long lifetime of the project. Its exclusion is consistent with other approved protocols in the Alberta emission offset system.</td>
</tr>
<tr>
<td>B5</td>
<td>Affected</td>
<td>N/A</td>
<td>Exclude</td>
<td>Capture does not occur in Baseline.</td>
</tr>
<tr>
<td>Identified SSRs</td>
<td>Baseline (C,R,A)</td>
<td>Project (C,R,A)</td>
<td>Include or Exclude from Quantification</td>
<td>Justification</td>
</tr>
<tr>
<td>--------------------------------------------------------------------------------</td>
<td>-----------------</td>
<td>----------------</td>
<td>----------------------------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>P7 Construction of EOR Facilities and Well Drill and Service</td>
<td>N/A</td>
<td>Related</td>
<td>Include *Include Reportable Drilling Releases only</td>
<td>The construction of EOR facilities is a one-time only source of greenhouse gas emissions and is negligible compared to the expected size and long lifetime of the project. Therefore, these construction emissions do not need to be included. *Any drilling releases that trigger Alberta Energy Regulator’s Directive 059 reporting threshold for kicks or blowouts must be included in the project emissions.</td>
</tr>
<tr>
<td>B7 Construction of EOR Facilities and Well Drill and Service</td>
<td>Affected</td>
<td>N/A</td>
<td>Exclude</td>
<td>Activity for EOR does not occur in Baseline.</td>
</tr>
<tr>
<td>P24 Land Clearance and Soil Carbon Loss from Construction of EOR Facilities</td>
<td>N/A</td>
<td>Related</td>
<td>Exclude</td>
<td>This one-time only source of greenhouse gas emissions is negligible compared to the expected size and long lifetime of the project. Its exclusion is consistent with other approved protocols in the Alberta emission offset system. Activity for EOR deemed to be equivalent in both baseline and project condition.</td>
</tr>
<tr>
<td>B24 Land Clearance and Soil Carbon Loss from Construction of EOR Facilities</td>
<td>Affected</td>
<td>N/A</td>
<td>Exclude</td>
<td></td>
</tr>
<tr>
<td>On-site SSRs</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>P1 Injected CO₂</td>
<td>Controlled</td>
<td>N/A</td>
<td>Exclude</td>
<td>Project condition is projected to baseline condition.</td>
</tr>
<tr>
<td>B1 Injected CO₂</td>
<td>N/A</td>
<td>Controlled</td>
<td>Include</td>
<td>This is the project activity of injection of new CO₂ from a large emitter for use in EOR emission offset project.</td>
</tr>
<tr>
<td>P2 Injected CH₄</td>
<td>Controlled</td>
<td>N/A</td>
<td>Exclude</td>
<td>The injected CH₄ is not eligible to be quantified as injected CO₂ as it is also a fuel.</td>
</tr>
<tr>
<td>B2 Injected CH₄</td>
<td>N/A</td>
<td>Controlled</td>
<td>Exclude</td>
<td>No emission reduction allowed for the injection of CH₄.</td>
</tr>
<tr>
<td>P3 Injected N₂O</td>
<td>Controlled</td>
<td>N/A</td>
<td>Exclude</td>
<td>The injected nitrous oxide is not eligible to be quantified as injected CO₂, as it is a product of incomplete separation.</td>
</tr>
<tr>
<td>B3 Injected N₂O</td>
<td>N/A</td>
<td>Controlled</td>
<td>Exclude</td>
<td>No emission reduction allowed for the injection of N₂O</td>
</tr>
<tr>
<td>B4 Re-Injected Fluid</td>
<td>Controlled</td>
<td>N/A</td>
<td>Exclude</td>
<td>Activity for EOR does not occur in Baseline.</td>
</tr>
<tr>
<td>P4 Re-injected Fluid</td>
<td>N/A</td>
<td>Controlled</td>
<td>Exclude</td>
<td>The emissions from this source have been accounted for by installing the meter for B1 as close as possible to the injection point but prior to the point where re-injected (recycled) gas enters the gas stream.</td>
</tr>
<tr>
<td>P12 On-Site Electricity Generation</td>
<td>N/A</td>
<td>Controlled</td>
<td>Include</td>
<td>This source may have a material impact on project emissions.</td>
</tr>
<tr>
<td>Identified SSRs</td>
<td>Baseline (C,R,A)</td>
<td>Project (C,R,A)</td>
<td>Include or Exclude from Quantification</td>
<td>Justification</td>
</tr>
<tr>
<td>---------------------------------</td>
<td>------------------</td>
<td>-----------------</td>
<td>----------------------------------------</td>
<td>------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>B12 On-Site Electricity Generation</td>
<td>Controlled</td>
<td>N/A</td>
<td>Exclude</td>
<td>Activity for EOR does not occur in Baseline.</td>
</tr>
<tr>
<td>P13 Fuel Consumption</td>
<td>N/A</td>
<td>Controlled</td>
<td>Include</td>
<td>This source may have a material impact on project emissions.</td>
</tr>
<tr>
<td>B13 Fuel Consumption</td>
<td>Controlled</td>
<td>N/A</td>
<td>Exclude</td>
<td>Activity for EOR does not occur in Baseline.</td>
</tr>
<tr>
<td>P14 Venting at Capture Site</td>
<td>N/A</td>
<td>Controlled</td>
<td>Exclude</td>
<td>The emission source is accounted for by the large emitter that supplies the CO₂.</td>
</tr>
<tr>
<td>B14 Venting at Capture Site</td>
<td>Controlled</td>
<td>N/A</td>
<td>Exclude</td>
<td>Activity for EOR does not occur in Baseline.</td>
</tr>
<tr>
<td>P15 Fugitive Emissions at Capture Site</td>
<td>N/A</td>
<td>Related</td>
<td>Exclude</td>
<td>The emission source is accounted for by the large emitter that supplies the CO₂.</td>
</tr>
<tr>
<td>B15 Fugitive Emissions at Capture Site</td>
<td>Related</td>
<td>N/A</td>
<td>Exclude</td>
<td>Activity for EOR does not occur in Baseline.</td>
</tr>
<tr>
<td>P16 Venting at Compression/Dehydration</td>
<td>N/A</td>
<td>Controlled</td>
<td>Exclude</td>
<td>The emission source is accounted for by the large emitter that supplies the CO₂.</td>
</tr>
<tr>
<td>B16 Venting at Compression/Dehydration</td>
<td>Controlled</td>
<td>N/A</td>
<td>Exclude</td>
<td>Activity for EOR does not occur in Baseline.</td>
</tr>
<tr>
<td>P17 Fugitives at Compression/Dehydration</td>
<td>N/A</td>
<td>Related</td>
<td>Exclude</td>
<td>The emission source is accounted for by the large emitter that supplies the CO₂.</td>
</tr>
<tr>
<td>B17 Fugitives at Compression/Dehydration</td>
<td>Related</td>
<td>N/A</td>
<td>Exclude</td>
<td>Activity for EOR does not occur in Baseline.</td>
</tr>
<tr>
<td>P18 Venting during Transport</td>
<td>N/A</td>
<td>Controlled</td>
<td>Exclude</td>
<td>The emission source is accounted for by the large emitter that supplies the CO₂.</td>
</tr>
<tr>
<td>B18 Venting during Transport</td>
<td>Controlled</td>
<td>N/A</td>
<td>Exclude</td>
<td>Activity for EOR does not occur in Baseline.</td>
</tr>
<tr>
<td>P19 Fugitive Emissions during Transport</td>
<td>N/A</td>
<td>Related</td>
<td>Exclude</td>
<td>The emission source is accounted for by the large emitter that supplies the CO₂.</td>
</tr>
<tr>
<td>Identified SSRs</td>
<td>Baseline (C,R,A)</td>
<td>Project (C,R,A)</td>
<td>Include or Exclude from Quantification</td>
<td>Justification</td>
</tr>
<tr>
<td>----------------</td>
<td>------------------</td>
<td>----------------</td>
<td>---------------------------------------</td>
<td>---------------</td>
</tr>
<tr>
<td>B19 Fugitive Emissions during Transport</td>
<td>Related</td>
<td>N/A</td>
<td>Exclude</td>
<td>Activity for EOR does not occur in Baseline.</td>
</tr>
<tr>
<td>P20 Venting at Injection/Production Wells and in Recycle Stream</td>
<td>N/A</td>
<td>Controlled</td>
<td>Include</td>
<td>This source/sink must be included because it may occur downstream of the injection meter. Resulting emissions may have material impact on project emissions.</td>
</tr>
<tr>
<td>B20 Venting at Injection/Production Wells and Recycle</td>
<td>Controlled</td>
<td>N/A</td>
<td>Exclude</td>
<td>Activity for EOR does not occur in Baseline.</td>
</tr>
<tr>
<td>P21 Fugitive Emissions at Injection/Production Wells and Recycle</td>
<td>N/A</td>
<td>Related</td>
<td>Include</td>
<td>This source/sink must be included because it may occur downstream of the injection meter. Resulting emissions may have material impact on project emissions.</td>
</tr>
<tr>
<td>B21 Fugitive Emissions at Injection/Production Wells and Recycle</td>
<td>Related</td>
<td>N/A</td>
<td>Exclude</td>
<td>Activity for EOR does not occur in Baseline.</td>
</tr>
<tr>
<td>P22 Emissions from Subsurface to Atmosphere</td>
<td>N/A</td>
<td>Related</td>
<td>Include</td>
<td>This source/sink must be included because it may occur downstream of the injection meter. Resulting emissions may have material impact on project emissions.</td>
</tr>
<tr>
<td>B22 Emissions from Subsurface to Atmosphere</td>
<td>Related</td>
<td>N/A</td>
<td>Exclude</td>
<td>Activity for CO₂-EOR does not occur in Baseline.</td>
</tr>
<tr>
<td>P23 Decommissioning of Enhanced Oil Recovery Facilities</td>
<td>N/A</td>
<td>Related</td>
<td>Exclude</td>
<td>This source/sink results in negligible greenhouse gas emissions compared to the expected size and long lifetime of the project. These emissions are excluded, consistent with other approved protocols in the Alberta emission offset system.</td>
</tr>
<tr>
<td>B23 Decommissioning of Enhanced Oil Recovery Facilities</td>
<td>Related</td>
<td>N/A</td>
<td>Exclude</td>
<td>The emissions from this activity are negligible relative to total project emissions and reductions.</td>
</tr>
<tr>
<td>P26 Flare at Injection/Production Wells and Recycle</td>
<td>N/A</td>
<td>Controlled</td>
<td>Include</td>
<td>This source/sink must be included because it may occur downstream of the injection meter. Resulting emissions may have material impact on project emissions.</td>
</tr>
<tr>
<td>B26 Flare at Injection/Production Wells and Recycle</td>
<td>Controlled</td>
<td>N/A</td>
<td>Exclude</td>
<td>Activity for EOR does not occur in Baseline.</td>
</tr>
</tbody>
</table>

**Downstream SSRs**

| P25 Loss, Disposal, or Recycling of Materials Used in CO₂ Capture Processes | N/A | Related | Include | Resulting emissions may have material impact on project emissions. |
| B25 Loss, Disposal, or Recycling of Materials Used in CO₂ Capture Processes | Affected | N/A | Exclude | Activity for CO₂-EOR does not occur in Baseline. |
4.1. Quantification Methodology

The quantification methodology includes net emission reductions, offset-eligible emission reductions and priced emission reductions. In some projects, some SSRs may be subject to a carbon price, whereas in others they may not be subject to a carbon price. The project developer will need to determine if the SSRs are subject to a carbon price and whether or not to include them in offset-eligible or priced emission reduction, depending on the project and the regulatory status of the site at which the project is implemented. Regardless, the net geological sequestration as a result of this emission offset project is quantified by calculating associated emissions and CO\textsubscript{2} geological sequestration from included SSRs in both the baseline and project conditions and calculating the difference. Table 6 outlines the required quantification methodology in application of this protocol.

Quantification of the emissions, reductions, removals and reversals of relevant SSRs for each of the greenhouse gases must be completed using the quantification procedures outlined below. These quantification procedures serve to complete the following equations for calculating the emission reductions from the comparison of the baseline and project conditions.

Essential to the quantification is an understanding and appropriate treatment of carbon pricing, either federal and/or provincial, on the calculation of the offset eligible emission reductions. Emissions and reductions that are not subject to a carbon price or surcharge (or exempt from a carbon price) are eligible for emission offsets. Facilities regulated under Alberta’s GHG Regulation are exempt from the federal fuel charge and CO\textsubscript{2} exported from the regulated large emitter or opt-in facilities is eligible to be sequestered and generate emission offsets. Emissions and reductions that are subject to a carbon price or surcharge are not eligible for emission offsets. The equations for priced emissions are primarily applicable to sources that combust fossil fuels. Projects that quantify emission offsets must also quantify and report priced (non-offset eligible) emissions and reductions.

Projects must identify and categorize all baseline and project emission SSRs included in the quantification as either “priced” or “non-priced” sources of emissions based on applicable Federal and/or Provincial legislation that is in place during the reporting period covered by the offset project report. Priced emission sources are to be reported but are not included in the calculation of emission offsets. Net geological sequestrations are calculated based on the difference between eligible Baseline and Project quantification.
4.2. Net Geological Sequestration

Outlined below is the general approach to quantifying the net geological sequestration.

<table>
<thead>
<tr>
<th>Project Assertion (the following items must be listed separately in Project Report and be itemized by reporting period and by vintage year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Discount Emission Reductions = Emissions Baseline * D</td>
</tr>
<tr>
<td>Holdback Emission Reductions = Emissions Baseline * H</td>
</tr>
</tbody>
</table>

D - Discount applied to injected CO₂ for unintentional reversals. Set equal to 0.005

H \((H₁, H₂)\) - Holdback applied to injected CO₂ to set aside emission offsets for potential future intentional reversal(s) for a Type 1 or Type 2 CO₂-EOR Scheme.

Holdback \((H₁)\) = 0 for emission offset project crediting period year 1, 2, 3 and 4 inclusive; then 0.02 for year 5 onward for each reporting period, including extensions, for Type 1 EOR schemes;

Holdback \((H₂)\) = 0.5 for all reporting periods for Type 2 EOR schemes.

Note: The Holdback is considered to be a future Net Geological Sequestration assuming the holdback criteria are satisfied.

Baseline emissions are calculated according to the following, which is in alignment with the Baseline SSRs listed as “included” in Table 5:

Baseline emissions are calculated according to the following:

\[ \text{Emissions Baseline} = \text{Emissions Injected CO}_2 \]

Baseline emission sources include the following:

\[ \text{Emissions Baseline} = \text{sum of emissions projected from the measured quantity and concentration of CO}_2 \text{ injected in the project condition but does not include CH}_4, \text{N}_2\text{O or re-injected (recycled or transferred) CO}_2. \]

\[ \text{Emissions Injected CO}_2 = \text{sum of emissions under B1 Injected CO}_2 \]

Project emissions are calculated according to the following:

\[ \text{Emissions Project} = \text{Emissions Production and Delivery of Materials used in CO}_2 \text{ Capture Process} + \text{Emissions Construction of EOR Facilities and well drill and service} + \text{Emissions Fuel Extraction and Processing} + \text{Emissions Fuel Delivery} + \text{Emissions Off-Site Electricity Generation} + \text{Emissions Off-Site Heat Generation} + \text{Emissions Construction of EOR Facilities and well drill and service} + \text{Emissions Fuel Consumption} + \text{Emissions Venting at Injection and Production Wells} + \text{Emissions Fugitive at Injection and Production Wells and Recycle Stream} + \text{Emissions Subsurface to Atmosphere} + \text{Emissions Loss, Disposal or Recycling of Material Inputs} + \text{Emissions Flare at Injection/Production Wells and Recycle Stream} \]

Project emission sources include the following:

\[ \text{Emissions Project} = \text{sum of emissions under the project condition} + \text{emissions under P6 Production and Delivery of Materials used in construction of EOR facility, capture facility and transport facility} + \text{emissions under P7 Production and Construction of EOR Facilities and well drill and service} + \text{emissions under P8 Fuel Extraction/ Processing} + \text{emissions under P9 Fuel Delivery} + \text{emissions under P10 Off-Site Electricity Generation} + \text{emissions under P11 Off-Site Heat Generation} + \text{emissions under P12 On-Site Electricity Generation} + \text{emissions under P13 Fuel Consumption} + \text{emissions under P20 Venting at Injection and Production Wells and in Recycle Stream} + \text{emissions under P21 Fugitive at Injection, Recycle and Production Wells} + \text{emissions under P22 Emissions from Subsurface to Atmosphere} + \text{emissions under P25 Emissions from Loss, Disposal or Recycling of Materials Inputs} + \text{emissions under P26 Flare at injection/production wells and recycle stream} \]

Total CO₂e Equivalent Emissions = \[ \sum (\text{CO}_2 \text{ emissions}) + \sum (\text{CH}_4 \text{ emissions})*\text{GWP}_{\text{CH}_4} + \sum (\text{N}_2\text{O emissions})*\text{GWP}_{\text{N}_2\text{O}} \]

Where:
CO₂e Equivalent Emissions = sum of all greenhouse gas emissions converted to CO₂ equivalent terms, and does not apply to injected quantities of CH₄ or N₂O

GWP = Global Warming Potential for each greenhouse gas as listed in Standard for Completing Greenhouse Gas Compliance and Forecasting Reports
4.3. Offset Eligible Emission Reductions (non-priced emissions)

Reductions of emissions that are not subject to a carbon price are eligible for emission offsets; reductions of emissions that are subject to a carbon price are not eligible for emission offsets. Projects that quantify offset eligible emission reductions must also quantify and report on priced emission reductions as per section 4.1.3.

\[
\text{Offset Eligible Emission Reductions} = \text{Emissions Non-priced Baseline} - \text{Emissions Non-priced Project}
\]

4.3.1. Priced Emission Reductions

Emissions that are subject to a carbon price are not eligible for emission offsets. Projects (and subprojects) must quantify and report on reductions of emissions that are subject to a carbon price.

Priced emission reductions are calculated from a comparison of project and baseline emissions for all SSRs that are subject to a carbon price. Some emissions may be subject to a carbon price in some scenarios and not in others. It is the responsibility of the emission offset project developer to ensure that SSRs that are subject to a carbon price are included in the quantification of priced emission reductions.
Table 6: Quantification Procedures

<table>
<thead>
<tr>
<th>Sources/ Sinks</th>
<th>Parameter / Variable</th>
<th>Units</th>
<th>Measured/ Estimated</th>
<th>Method</th>
<th>Frequency</th>
<th>Justification for Measurement or Estimation and Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Baseline SSRs</td>
<td>Emissions Injected CO₂ = ∑ (Vol. Injected Fluid * ρCO₂ * % Injected CO₂)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Emissions Injected CO₂</td>
<td>t of CO₂e</td>
<td>Measured</td>
<td></td>
<td></td>
<td>This value refers to the injected quantity of CO₂ measured at the metering point in the project condition. The measured volume, concentration, temperature and pressure are used to calculate the mass of CO₂e emitted (excludes CH₄ and N₂O)</td>
</tr>
<tr>
<td></td>
<td>Volume of injected fluid / Vol. Injected Fluid</td>
<td>m³</td>
<td>Measured</td>
<td></td>
<td></td>
<td>Direct metering of volume of gas measured at the metering point in the project condition, as close as practical to injection but prior to re-injected fluid injection point</td>
</tr>
<tr>
<td></td>
<td>Density of CO₂ / ρ CO₂</td>
<td>kg/m³ or t/e³m³</td>
<td>Estimated</td>
<td></td>
<td></td>
<td>Must use a reference density of CO₂, corrected to the STP conditions at which the volumes of gas are reported. Data conversions from all pressure and temperature compensated instruments must be sure to use the same pressure or temperature used for the specific meter calibration</td>
</tr>
<tr>
<td>Sources/ Sinks</td>
<td>Parameter / Variable</td>
<td>Units</td>
<td>Measured/ Estimated</td>
<td>Method</td>
<td>Frequency</td>
<td>Justification for Measurement or Estimation and Frequency</td>
</tr>
<tr>
<td>----------------</td>
<td>----------------------</td>
<td>-------</td>
<td>---------------------</td>
<td>--------</td>
<td>-----------</td>
<td>----------------------------------------------------------</td>
</tr>
<tr>
<td></td>
<td>Concentration of injected CO₂ / % Injected CO₂</td>
<td>%Volume/% Mole</td>
<td>Measured</td>
<td>The CO₂ concentration must be directly measured downstream of the capture and processing equipment or upstream of the injection field at a custody transfer point. When additional CO₂ streams comingle with a capture stream of known concentration, the concentration of comingled stream must be confirmed either by direct measurement of the comingled stream or by mass balance and a measurement of the additional capture stream. The measurement sample point may occur downstream of the tie in such that the concentration of the comingled stream is taken. Alternatively, the measurement can be taken downstream of the additional capture stream but upstream of comingling. In this case, the concentration of the comingled stream can be calculated by solving a single variable mass balance equation.</td>
<td>Continuous (At minimum, a sample every three hours averaged daily on a volumetric basis for emission offset projects subject to a 2% materiality threshold. A minimum of one monthly sample to allow weighted average, on volumetric basis, to be used for emission offset projects subject to 5% materiality threshold)</td>
<td>Direct metering is standard practice. Frequency of metering is highest level possible (See Standard for GHG Offset Project Developers for information on materiality threshold)</td>
</tr>
</tbody>
</table>

### Project SSRs

<table>
<thead>
<tr>
<th>Emissions Production &amp; Delivery of Material Inputs</th>
<th>t of CO₂e</th>
<th>N/A</th>
<th>N/A</th>
<th>N/A</th>
<th>Quantity being calculated in aggregate based on quantity of inputs used throughout the carbon capture operations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emissions Production &amp; Delivery of Material Inputs</td>
<td>t of CO₂e</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>Quantity being calculated in aggregate based on quantity of inputs used throughout the carbon capture operations</td>
</tr>
<tr>
<td>Quantity of material inputs consumed for carbon capture facility operation / Input i</td>
<td>t / L / m³ / Other</td>
<td>Estimated</td>
<td>Estimation of the quantity of material inputs consumed for the carbon capture process</td>
<td>Annual or by reporting period</td>
<td>Procurement records or an engineering report will specify the quantity of material input required for an appropriately sized carbon capture facility. Represents most reasonable means of estimation</td>
</tr>
<tr>
<td>Emissions factor for each type of material input / EF Input / CO₂, CH₄, N₂O</td>
<td>t CO₂e per t / L / m³ / other</td>
<td>Estimated</td>
<td>Emission offset project specific design</td>
<td>Annual</td>
<td>Production and delivery estimates for the emission factors for the material inputs</td>
</tr>
<tr>
<td>Sources/ Sinks</td>
<td>Parameter / Variable</td>
<td>Units</td>
<td>Measured/ Estimated</td>
<td>Method</td>
<td>Frequency</td>
</tr>
<tr>
<td>---------------</td>
<td>---------------------</td>
<td>-------</td>
<td>---------------------</td>
<td>--------</td>
<td>-----------</td>
</tr>
<tr>
<td></td>
<td><strong>Emissions</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Drill and Service Injection Well Sites = ( \sum (\text{Vol. Gas Kick} \times % \text{ CO}_2, \text{ CH}_4, \text{ N}_2O \times \rho \text{ CO}_2, \text{ CH}_4, \text{ N}_2O) \times \text{GWP CH}_4, \text{ N}_2O )</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Emissions Venting at Wells</td>
<td>tonnes of CO\text{2e}</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td>Volume of Vented Gas / Vol. Gas Kick</td>
<td>( \text{m}^3 )</td>
<td>Estimated</td>
<td>If the drilling or service activity resulted in a kick or a blowout, Directive 59 submission is triggered. The values submitted in the Directive 59 report should be used to estimate the volume of gas released. (May be a vented or fugitive emission)</td>
<td>Engineering estimate per event</td>
</tr>
<tr>
<td></td>
<td>Concentration of gas vented/ % \text{ CO}_2, \text{ CH}_4, \text{ N}_2O</td>
<td>% volume</td>
<td>Measured</td>
<td>A measured gas analysis should be obtained</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td>Density of vented gas / \rho \text{ CO}_2, \text{ CH}_4, \text{ N}_2O</td>
<td>\text{t/m}^3</td>
<td>Estimated</td>
<td>Site specific, based on gas analysis. If not possible, must use a reference density, corrected to the conditions at which the volumes of gas are reported. Data conversions from all pressure and temperature compensated instruments must be sure to use the same standard temperature and pressure (STP) used for the specific meter calibration.</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td>GWP\text{CH}_4, \text{ N}_2O</td>
<td>Unitless</td>
<td>Estimated</td>
<td>As per Standard for Completing Greenhouse Gas Compliance and Forecasting Reports</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td><strong>Emissions</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Fuel Extraction and Processing = ( \sum (\text{Fuel Used} \times \text{EF Fuel} \times \text{ CO}_2, \text{ CH}_4, \text{ N}_2O) \times \text{GWP CH}_4, \text{ N}_2O )</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Emissions Fuel Extraction and Processing</td>
<td>t of CO\text{2e}</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>
## Quantification Protocol for Enhanced Oil Recovery

**Sources/Sinks**

<table>
<thead>
<tr>
<th>Parameter / Variable</th>
<th>Units</th>
<th>Measured/Estimated</th>
<th>Method</th>
<th>Frequency</th>
<th>Justification for Measurement or Estimation and Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total quantity of fossil fuels consumed to operate each component of the CO₂-EOR scheme operations (Capture, Transport and Storage/Recycle)/ Vol. Fuel Used</td>
<td>e³m³/MJ/ Other</td>
<td>Measured</td>
<td>Calculated based on measurement of the quantity of each of the fuels used on-site</td>
<td>Continuous</td>
<td>Both methods are standard practice. Allocation of metered quantities is permitted (i.e., to separate out emissions for oil handling, etc.) Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence</td>
</tr>
<tr>
<td>Emissions factors for extraction and processing of each type of fuel / EF Fuel i CO₂, CH₄, N₂O</td>
<td>t CO₂e per e³m³ / MJ/ other</td>
<td>Estimated</td>
<td>Carbon Offset Emission Factors Handbook</td>
<td>Annual</td>
<td>These reference values represent best available emission factors for fuel extraction and processing</td>
</tr>
<tr>
<td>GWP(CH₄, N₂O) Global Warming Potential</td>
<td>Unitless</td>
<td>Estimated</td>
<td>As per Standard for Completing Greenhouse Gas Compliance and Forecasting Reports</td>
<td>N/A</td>
<td>Section 1(3) of TIER requires that offset projects use the GWPs published in the most recent version of the Standard</td>
</tr>
</tbody>
</table>

### Emissions Fuel Delivery

\[ \text{Emissions Fuel Delivery} = \sum (\text{Fuel Used } i \times \text{EF Used } i \text{CO}_2, \text{CH}_4, \text{N}_2O) \times \text{GWP CH}_4, \text{N}_2O \]

<table>
<thead>
<tr>
<th>Emissions Fuel Delivery</th>
<th>t of CO₂e</th>
<th>N/A</th>
<th>N/A</th>
<th>N/A</th>
<th>Quantity being calculated in aggregate based on quantity fuel used</th>
</tr>
</thead>
</table>

### P9 Fuel Delivery

<table>
<thead>
<tr>
<th>Quantity of Fuel Used to operate each component of the CO₂-EOR scheme operations (Capture, Transport and Storage/Recycle)/ Vol. Fuel Used</th>
<th>L/ e³m³/ Other</th>
<th>Calculated</th>
<th>Calculated based on measurement of the quantity of each of the fuels used on-site</th>
<th>Continuous</th>
<th>Both methods are standard practice. Allocation of metered quantities is permitted (i.e., to separate out emissions for oil handling, etc.) Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emissions factor for each type of fuel consumed in transport of fuel / EF Used i CO₂, CH₄, N₂O</td>
<td>t CO₂e per L/ e³m³/ other</td>
<td>Calculated</td>
<td>Carbon Offset Emission Factors Handbook</td>
<td>Annual</td>
<td>Production and delivery estimates for the emission factors for the material inputs</td>
</tr>
<tr>
<td>GWP(CH₄, N₂O) Global Warming Potential</td>
<td>Unitless</td>
<td>Estimated</td>
<td>As per Standard for Completing Greenhouse Gas Compliance and Forecasting Reports</td>
<td>N/A</td>
<td>Section 1(3) of TIER requires that offset projects use the GWPs published in the most recent version of the Standard</td>
</tr>
<tr>
<td>Sources/ Sinks</td>
<td>Parameter / Variable</td>
<td>Units</td>
<td>Measured/ Estimated</td>
<td>Method</td>
<td>Frequency</td>
</tr>
<tr>
<td>---------------</td>
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<td>--------</td>
<td>-----------</td>
</tr>
<tr>
<td>P10 Off-Site Electricity Generation</td>
<td>Emissions Off-Site Electricity Generation = Electricity Off-Site Electricity Generation</td>
<td>t CO₂e</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td>Total quantity of grid delivered electricity consumed for enhanced oil recovery emission offset project / Electricity Grid</td>
<td>MWh</td>
<td>Measured</td>
<td></td>
<td>Continuous metering</td>
</tr>
<tr>
<td></td>
<td>Grid emission intensity factor for electricity generation / EF Grid</td>
<td>t CO₂e / MWh</td>
<td>Estimated</td>
<td></td>
<td>Annual</td>
</tr>
<tr>
<td></td>
<td>Quantity of incremental generating capacity</td>
<td>MWh</td>
<td>Calculated</td>
<td></td>
<td>Annual</td>
</tr>
</tbody>
</table>

**Emissions Off-Site Electricity Generation = Electricity Off-Site Electricity Generation**

Where: Offsite electricity must be incremental and directly connected to the source (LE, Offset project or Non LE) in order to use the particular source emission factor (EF), otherwise the grid factor applies.

Electricity LE, Non LE = Minimum (Electricity Total Gen. − Electricity Average Gen. Electric Power Purchased through Dedicated Contract)

Where: Electricity is the lesser of the difference between total and average generation, and the electricity purchased through a dedicated contract.

That is, Electricity LE, Non LE is the lesser of the quantity of generated electricity in the offset reporting period beyond average generation in the 3 baseline years or generation from new capacity installed, and the quantity of generated electricity that was under contract to the emission offset project in the reporting period.

Where: Average generation is the amount of electricity generated by the facility from the 3-year reference period prior to emission offset project initiation.

Incremental Generating Capacity is determined by proof of:
- the installed capacity that was not used in each of the 3 baseline years,
- the generation that was under contract in each of the 3 baseline years, and
- new capacity installed.

The Average Year means the weighted average of the incremental generation capacity of the 3 baseline years.

**EF Grid electricity =** Carbon Offset Emission Factors Handbook (use increased on-site grid electricity use (includes line loss))

**EF Offset electricity =** Carbon Offset Emission Factors Handbook for (electricity grid displacement with renewable generation (for renewable generation at point of use))

**EF LE Electricity =** High Performance Benchmark for Electricity (From TIER regulation)

**EF Non LE, Non Offset Electricity =** Actual Emissions Intensity for Incremental, Directly Connected Electricity Generation
<table>
<thead>
<tr>
<th>Sources/ Sinks</th>
<th>Parameter / Variable</th>
<th>Units</th>
<th>Measured/ Estimated</th>
<th>Method</th>
<th>Frequency</th>
<th>Justification for Measurement or Estimation and Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>consumed at the project / Electricity</td>
<td>Total Gen.</td>
<td>MWh</td>
<td>Measured</td>
<td>reference period, as well as direct measurement of electricity delivered to the emission offset project from each source. Measured values must be used to calculate incremental generating capacity. The generating facility must meet the glossary definition for incremental generating capacity. All electricity that does not meet the definition of incremental generating capacity is considered to be grid electricity. The electricity included in this category from each directly connected source must be purchased through a dedicated contract. It is assumed that electricity generated from a directly connected renewable emission offset project has generated emission offsets or renewable energy certificates</td>
<td>Annual or by reporting period</td>
<td>practice and the highest level of detail</td>
</tr>
<tr>
<td>Quantity of total electricity generation / Electricity</td>
<td>MWh</td>
<td>Measured</td>
<td>Total annual electricity generation of the facility supplying electricity to the emission offset project</td>
<td>Annual or by reporting period</td>
<td>Continuous direct metering represents the industry practice and the highest level of detail</td>
<td></td>
</tr>
<tr>
<td>Quantity of average electricity generation / Electricity</td>
<td>MWh</td>
<td>Measured</td>
<td>Average annual electricity generation in the three year reference period, prior to emission offset project initiation, of the facility supplying electricity to the emission offset project</td>
<td>Annual or by reporting period</td>
<td>Continuous direct metering represents the industry practice and the highest level of detail</td>
<td></td>
</tr>
<tr>
<td>Quantity of electricity purchased through a dedicated contract/ Electricity</td>
<td>MWh</td>
<td>Measured</td>
<td>Total electricity purchased through contractual agreement for use by the emission offset project during the reporting period</td>
<td>Annual or by reporting period</td>
<td>Continuous direct metering represents the industry practice and the highest level of detail</td>
<td></td>
</tr>
<tr>
<td>Quantity of electricity generated by an emission offset project/ Electricity</td>
<td>MWh</td>
<td>Measured</td>
<td>Total electricity produced through an emission offset project for use by the EOR emission offset project during the reporting period</td>
<td>Annual or by reporting period</td>
<td>Continuous direct metering represents the industry practice and the highest level of detail</td>
<td></td>
</tr>
<tr>
<td>Emission intensity factor for electricity generation from an offset project/ EF offset electricity</td>
<td>t CO₂e / MWh</td>
<td>Calculated</td>
<td>Available in Carbon Offset Emission Factors Handbook for (electricity grid displacement with renewable generation (for renewable generation at point of use)</td>
<td>Annual or by reporting period</td>
<td>Established methodology as per the Alberta emission offset system</td>
<td></td>
</tr>
<tr>
<td>Established Benchmark for electricity generation/ EF LE</td>
<td>t CO₂e / MWh</td>
<td>Calculated</td>
<td>Large emitters account for electricity at the benchmark and report their emissions for exported electricity annually</td>
<td>Annual or by reporting period</td>
<td>Established electricity benchmark as listed in provincial GHG regulation</td>
<td></td>
</tr>
<tr>
<td>Emission intensity factor for electricity generation from a non- LE facility / EF Non LE</td>
<td>t CO₂e / MWh</td>
<td>Calculated</td>
<td>The emission intensity factor for electricity produced at a non-LE facility is calculated by multiplying the measured total quantity of each fuel consumed for electricity generation by each associated fuel emission factor and dividing by the total produced electricity from the facility</td>
<td>Annual</td>
<td>Calculated based on the total amount of fuel consumed to produce the electricity by the non-LE facility</td>
<td></td>
</tr>
<tr>
<td>Sources/ Sinks</td>
<td>Parameter / Variable</td>
<td>Units</td>
<td>Measured/ Estimated</td>
<td>Method</td>
<td>Frequency</td>
<td>Justification for Measurement or Estimation and Frequency</td>
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<td>----------------------------------------------------------</td>
</tr>
<tr>
<td></td>
<td><strong>Emissions Off-Site Heat Generation</strong></td>
<td>t CO₂e</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>Quantity being calculated based on total quantity of heat sourced from off site. Sources from a Large Emitter and from an industrial facility not regulated are included.</td>
</tr>
<tr>
<td>P11 Off-Site Heat Generation</td>
<td><strong>Quantity of heat consumed by the emission offset project from an LE and from Non LE facility where heat is a product / ( \text{Heat}_{LE, \text{Non LE}} )</strong></td>
<td>GJ</td>
<td>Measured</td>
<td>Direct measurement of the quantity of heat used by the CO₂-EOR emission offset project</td>
<td>Annual</td>
<td>Continuous metering is standard for boundary transfer</td>
</tr>
<tr>
<td></td>
<td><strong>Benchmark for Industrial Heat Generation/ ( \text{EF}_{LE} )</strong></td>
<td>t CO₂e / GJ</td>
<td>N/A</td>
<td>Large emitters that export thermal energy to another large emitter, a CCS emission offset project or an EOR emission offset project account for it at the TIER benchmark for industrial heat</td>
<td>Annual</td>
<td>Established industrial heat benchmark as listed in Provincial GHG Regulation</td>
</tr>
<tr>
<td></td>
<td><strong>Emission intensity factor associated with heat from Non LE / ( \text{EF}_{Non LE} )</strong></td>
<td>t CO₂e / GJ</td>
<td>Calculated</td>
<td>Where heat is cogenerated, emissions allocated to heat production are calculated by determining the input energy attributed to heat production based on a boiler thermal efficiency of 80%</td>
<td>Annual</td>
<td>Calculated based on the total amount of heat produced and the total fuel consumed to produce that heat by the facility</td>
</tr>
<tr>
<td></td>
<td><strong>Emissions On-Site Electricity Generation</strong></td>
<td>t CO₂e</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>Quantity being calculated based on quantity of power sourced from on-site electricity generation facilities</td>
</tr>
<tr>
<td>P12 On-Site Electricity Generation</td>
<td><strong>Proportionate quantity of Fossil Fuels Consumed to Generate Power at On-Site Generation Facilities for Use by the EOR emission offset project / ( \text{Fuel}_{EOR} )</strong></td>
<td>L/ e^3m^3/ Other</td>
<td>Calculated</td>
<td>Calculated relative to the metered quantities of electricity delivered to the CO₂-EOR scheme from connected power generation facilities</td>
<td>Monthly</td>
<td>Allocation of Project Emissions based on proportion of total energy output from the electricity generation unit that is supplied to the enhanced oil recovery emission offset project is appropriate given that multiple energy users may source electricity from a power plant. Direct metering of electricity is appropriate</td>
</tr>
<tr>
<td>Sources/ Sinks</td>
<td>Parameter / Variable</td>
<td>Units</td>
<td>Measured/ Estimated</td>
<td>Method</td>
<td>Frequency</td>
<td>Justification for Measurement or Estimation and Frequency</td>
</tr>
<tr>
<td>---------------</td>
<td>-------------------------------------------------------------------------------------</td>
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<td>------------------------------------------------------------------------</td>
<td>-----------</td>
<td>-----------------------------------------------------------</td>
</tr>
<tr>
<td></td>
<td>Quantity of Fossil Fuels Consumed to Generate Electricity at On-Site Generation Facilities for Use by the EOR emission offset project / Fuel e</td>
<td>L/ e^3m^3/ Other</td>
<td>Measured</td>
<td>Direct measurement of the volume of fossil fuels consumed at power generation facility and/or other direct connected facilities that provide power to the emission offset project</td>
<td>Continuous metering</td>
<td>Continuous direct metering represents the industry practice and the highest level of detail</td>
</tr>
<tr>
<td></td>
<td>Emissions Factor for Combustion of Each Type of Fuel / EF Fuel i : CO2, CH4, N2O</td>
<td>t CO2 per L / e^3m^3/ other</td>
<td>Estimated</td>
<td>Carbon Offset Emission Factors Handbook</td>
<td>N/A</td>
<td>Must use most current factors published</td>
</tr>
<tr>
<td></td>
<td>Total Quantity of Electricity Supplied to End Users by the Generation Facility in the Project Condition / Elect</td>
<td>GJ</td>
<td>Measured</td>
<td>Direct metering of quantity of electricity delivered to all direct connected facilities from the generation plant; including the direct metering of the total electricity distributed to emission offset project, the regional electricity grid and an industrial system designation</td>
<td>Continuous Metering</td>
<td>Continuous direct metering represents the industry practice and the highest level of detail</td>
</tr>
<tr>
<td></td>
<td>GWP_{CH4, N2O} Global Warming Potential</td>
<td>Unitless</td>
<td>N/A</td>
<td>As per Standard for Completing Greenhouse Gas Compliance and Forecasting Reports</td>
<td>N/A</td>
<td>Section 1(3) of TIER requires that offset projects use the GWP s published in the most recent version of the Standard</td>
</tr>
</tbody>
</table>

Emissions Fuel Consumption = \[ \sum \left( \text{Vol. Fuel}_i \cdot \text{EF Used}_i \cdot \text{CO}_2 \right) + \sum \left( \text{Vol. Fuel}_i \cdot \text{EF Used}_i \cdot \text{CH}_4 \cdot \text{GWP}_{\text{CH}_4} \right) + \sum \left( \text{Vol. Fuel}_i \cdot \text{EF Used}_i \cdot \text{N}_2\text{O} \cdot \text{GWP}_{\text{N}_2\text{O}} \right) \] / 1000

<table>
<thead>
<tr>
<th>Parameter / Variable</th>
<th>Units</th>
<th>Method</th>
<th>Frequency</th>
<th>Justification for Measurement or Estimation and Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>P13 Fuel Consumption</td>
<td></td>
<td></td>
<td>Continuous metering or monthly reconciliation or allocation</td>
<td>Both methods are standard practice. Allocation of metered quantities is permitted (i.e., to separate out emissions for oil handling, etc.) Frequency of metering is highest level possible. Frequency of reconciliation provides for reasonable diligence</td>
</tr>
<tr>
<td>CO2 Emissions Factor for Combustion of Each Type of Fuel / EF Used i : CO2</td>
<td>kg CO2 per L / m^3/ other</td>
<td>Estimated</td>
<td>Carbon Offset Emission Factors Handbook</td>
<td>N/A</td>
</tr>
<tr>
<td>CH4 Emissions Factor for Combustion of Each Type of Fuel / EF Used i : CH4</td>
<td>kg CH4 per L / m^3/ other</td>
<td>Estimated</td>
<td>Carbon Offset Emission Factors Handbook</td>
<td>N/A</td>
</tr>
<tr>
<td>Sources/ Sinks</td>
<td>Parameter / Variable</td>
<td>Units</td>
<td>Measured/ Estimated</td>
<td>Method</td>
</tr>
<tr>
<td>---------------</td>
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</tr>
<tr>
<td>N₂O Emissions Factor for Combustion of Each Type of Fuel / EF Used</td>
<td>kg N₂O per L / m³ / other</td>
<td>Estimated</td>
<td>Carbon Offset Emission Factors Handbook</td>
<td>N/A</td>
</tr>
<tr>
<td>GWP for CH₄, N₂O Global Warming Potential</td>
<td>Unitless</td>
<td>Estimated</td>
<td>As per Standard for Completing Greenhouse Gas Compliance and Forecasting Reports</td>
<td>N/A</td>
</tr>
</tbody>
</table>

### Emissions Venting at Injection, Production Wells and Recycle Stream

\[
E = \sum (\text{Vol. Gas Vented} \times \% \text{ CO}_2, \text{ CH}_4, \text{ N}_2O \times \rho_{\text{CO}_2, \text{ CH}_4, \text{ N}_2O})
\]

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Units</th>
<th>Method</th>
<th>Frequency</th>
<th>Justification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Volume of Vent Gas / Vol. Gas Vented</td>
<td>L / e³m³ / other</td>
<td>Estimated</td>
<td>per event</td>
<td>This vented gas is downstream of the injection meter during maintenance blowdowns and should be determined as frequent as the maintenance event</td>
</tr>
<tr>
<td>Concentration in Vent Gas / % CO₂, CH₄, N₂O</td>
<td>%</td>
<td>Measured</td>
<td>A minimum of daily samples per event, when possible. Otherwise, estimated composition of the vented gas based on its source.</td>
<td></td>
</tr>
<tr>
<td>Density of Vent Gas / ρCO₂, CH₄, N₂O</td>
<td>t/e³m³</td>
<td>Estimated</td>
<td>N/A</td>
<td>Reference densities must be used consistently throughout emission offset project</td>
</tr>
</tbody>
</table>

### Emissions Fugitives at Injection/ Production Well and Recycle Stream

\[
E = \sum (\text{Fitting i} \times \text{ER Fitting i}) + \text{Other Fugitive Releases}
\]
<table>
<thead>
<tr>
<th>Sources/ Sinks</th>
<th>Parameter / Variable</th>
<th>Units</th>
<th>Measured/ Estimated</th>
<th>Method</th>
<th>Frequency</th>
<th>Justification for Measurement or Estimation and Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>and Recycle Stream</td>
<td>Emissions Fugitives at Injection/Production Well and Recycle Stream</td>
<td>t of CO\textsubscript{2}e</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>Quantity being calculated</td>
</tr>
<tr>
<td></td>
<td>Other Fugitive Releases</td>
<td>t of CO\textsubscript{2}e</td>
<td>Estimated</td>
<td>Engineering Estimate</td>
<td>Per Occurrence</td>
<td>This is from unintended/unplanned events, and accounts for CO\textsubscript{2} released after the meter but not from the storage complex. Estimated based on the most detailed information available</td>
</tr>
<tr>
<td></td>
<td>Number of Fittings after Metering Point / Fitting i</td>
<td>N/A</td>
<td>Estimated</td>
<td>Emission offset project specific design</td>
<td>Once</td>
<td>Estimated based on the number of fittings after the injection meter, piping and re-injection equipment above the subsurface</td>
</tr>
<tr>
<td></td>
<td>Emission Rate for Fitting and Equipment leaks / ER Fittings Equip i</td>
<td>t of CO\textsubscript{2}e/year</td>
<td>Calculated</td>
<td>Emission rate based on industry best practices for determining emissions based on actual field equipment and LDAR Measurement (using operating pressures and gas properties)</td>
<td>Minimum Annual</td>
<td>Emission offset project specific measurements represent the most accurate means</td>
</tr>
<tr>
<td>Emissions Subsurface to Atmosphere= Mass CO\textsubscript{2} leaked</td>
<td>P22 Emissions from Subsurface to Atmosphere</td>
<td>t of CO\textsubscript{2}e</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>Quantity being calculated.</td>
</tr>
<tr>
<td></td>
<td>Mass of CO\textsubscript{2} leaked from the Subsurface to Atmosphere/ Mass CO\textsubscript{2} leaked</td>
<td>t of CO\textsubscript{2}e</td>
<td>Estimated</td>
<td>If a leak event occurs, the mass of CO\textsubscript{2} leaked from the subsurface to the atmosphere shall be estimated with a maximum overall uncertainty over the reporting period of ±7.5%. In case overall uncertainty of the applied quantification approach exceeds ±7.5%, an adjustment shall be applied. Refer to Appendix B for further guidance</td>
<td>N/A</td>
<td>Estimation would be required for reporting to the AER. Direct measurement is likely not possible, but the use of engineering estimates and accounting for the uncertainty would be a reasonable approach in the event leakage occurs. To be conservative calculations may use the detection threshold</td>
</tr>
<tr>
<td></td>
<td>P25 Loss, Disposal, or Recycling of Materials Used in CO\textsubscript{2} Capture Processes</td>
<td>t of CO\textsubscript{2}e</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>Quantity being calculated in aggregate based on quantity of materials used for the emission offset project</td>
</tr>
<tr>
<td>Sources/ Sinks</td>
<td>Parameter / Variable</td>
<td>Units</td>
<td>Measured/ Estimated</td>
<td>Method</td>
<td>Frequency</td>
<td>Justification for Measurement or Estimation and Frequency</td>
</tr>
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</tr>
<tr>
<td></td>
<td>Total Volume of Material Lost, Disposed or Recycled from the CO₂ Capture Process/ Vol. Used</td>
<td>L/ m³ / Other</td>
<td>Estimated</td>
<td>Estimation of the volume of material inputs lost, disposed or recycled for the CO₂ capture process</td>
<td>N/A</td>
<td>Engineering report will specify the volume of material input lost, disposed or recycled for an appropriately sized Carbon Capture Facility. Represents most reasonable means of estimation. Loss, disposal or recycling estimates for the emission factors for the materials used</td>
</tr>
<tr>
<td></td>
<td>Emissions factor for each type of material input / EF Used</td>
<td>t CO₂e per L / m³ / other</td>
<td>Estimated</td>
<td>Emission offset project specific design</td>
<td>Annual</td>
<td>Production and delivery estimates for the emission factors for the material inputs</td>
</tr>
<tr>
<td></td>
<td>GWPCH₄, N₂O Global Warming Potential</td>
<td>Unitless</td>
<td>Estimated</td>
<td>Provided in IPCC, 2014: Synthesis Report, AR5</td>
<td>N/A</td>
<td>Must use most current factors published</td>
</tr>
<tr>
<td></td>
<td>Emissions flare</td>
<td>t CO₂e</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>Calculation of emissions from project flare, incinerator or combustor</td>
</tr>
<tr>
<td></td>
<td>Volume of Gas sent to Flare or Incinerator / Vol. Gas Flaring</td>
<td>e³m³</td>
<td>Measured</td>
<td>Online metering of volume of gas that is sent to flare or incinerator. Correlate to operational hours of flare or incinerator</td>
<td>Continuous metering, daily polling</td>
<td>Online metering is standard practice in the Alberta Greenhouse Gas Quantification Methodologies</td>
</tr>
<tr>
<td></td>
<td>Volume of Supplemental Gas to operate flare or incineration equipment at STP², Pilot purge and/or supplemental fuel / Vol. Supplemental Gas</td>
<td>e³m³ at STP</td>
<td>Measured or Estimated</td>
<td>Online metering of volume of gas used to operate the flare or incinerator (pilot/purge-supplemental fuel). If offline metering of volume of gas used to operate the flare or incinerator use method in Alberta Quantification Methodology</td>
<td>Continuous metering, daily polling Weekly</td>
<td>Online and offline metering is outlined in the Alberta Greenhouse Gas Quantification Methodology</td>
</tr>
<tr>
<td></td>
<td>Emission Factor for CO₂ / EF CO₂</td>
<td>t CO₂e/e³m³</td>
<td>Estimated</td>
<td>Site specific, calculated based on gas analysis using the procedures in Appendix C, Section C.1. of the Alberta Quantification Methodology. Alternatively, if this is not available, use the default value for rich gas for the appropriate device type (unassisted flare, assisted flare or incinerator) from the Flaring Chapter of the</td>
<td>Annual</td>
<td>Direct measurement will be the most accurate. See Flaring Chapter of the Alberta Greenhouse Gas Quantification Methodology</td>
</tr>
</tbody>
</table>

² STP (Standard Temperature and Pressure) is defined in this protocol as 15°C and 101.3 kPa.
<table>
<thead>
<tr>
<th>Sources/ Sinks</th>
<th>Parameter / Variable</th>
<th>Units</th>
<th>Measured/ Estimated</th>
<th>Method</th>
<th>Frequency</th>
<th>Justification for Measurement or Estimation and Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Alberta Greenhouse Gas Quantification Methodology</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Methane Composition of Flared Gas / % CH₄</td>
<td>%</td>
<td>Measured</td>
<td>Direct Measurement as outlined in Directive 017. Measurement of the concentration must be representative of the gas stream sent to flare. Alternatively, if this is not available, use the default value for rich gas from the Alberta Greenhouse Gas Quantification Methodology</td>
<td>Annual</td>
<td>Direct measurement is the most accurate using weighted average gas composition. See Flaring Chapter of the Alberta Greenhouse Gas Quantification Methodology</td>
</tr>
<tr>
<td></td>
<td>Density of CH₄ / ρCH₄</td>
<td>t/e³m³</td>
<td>Constant</td>
<td>0.6785 kg/m³ at STP</td>
<td>N/A</td>
<td>Accepted value as per Alberta Greenhouse Gas Quantification Methodology</td>
</tr>
<tr>
<td></td>
<td>Destruction Efficiency of Flare or Incinerator / DE</td>
<td>%</td>
<td>Estimated</td>
<td>Field measured destruction efficiency OR, if this is not available, use manufacturer’s specifications OR, if this is not available, use default methane destruction efficiency for unassisted flares in the Alberta Greenhouse Gas Quantification Methodology</td>
<td>Once</td>
<td>Field measured destruction efficiency will be most accurate and relevant, but many sites will not have this data. Where manufacturer’s specifications are available, these will be also be relevant. If neither is available, the unassisted flare defaults from the Alberta Greenhouse Gas Quantification Methodology are conservative</td>
</tr>
<tr>
<td></td>
<td>Emission Factor for N₂O / EF₉O</td>
<td>t N₂O/e³m³</td>
<td>Estimated</td>
<td>Use the default N₂O emission factor for flaring hydrocarbon gas from the Flaring Chapter of the Alberta Greenhouse Gas Quantification Methodologies.</td>
<td>Annual</td>
<td>See Flaring Chapter of the Alberta Quantification Methodology (note this does not vary by flare/incinerator device type)</td>
</tr>
<tr>
<td></td>
<td>Global Warming Potential / GWP₉CH₄,₉N₂O</td>
<td>Unitless</td>
<td>Estimated</td>
<td>As per Standard for Completing Greenhouse Gas Compliance and Forecasting Reports</td>
<td>N/A</td>
<td>Section 1(3) of TIER requires that offset projects use the GWPs published in the most recent version of the Standard</td>
</tr>
</tbody>
</table>

Quantification Protocol for Enhanced Oil Recovery
Classification: Public
5. Data Management

All emission offset projects must be supported with sufficient high quality data, and/or methods to fulfill the quantification requirements listed in this protocol, and be substantiated by records for the purpose of verification to a reasonable level of assurance. The Regulation requires that data must be quantifiable, measurable directly or by accurate estimation using replicable techniques. A third party assurance provider is responsible for evaluating the project and any assertions and must reach the same conclusions using evidence-supported data. The Alberta Emission Offset System does not accept data that is based on attestation and only accepts data that is verifiable.

In support of meeting project data requirements, data must be managed in a manner that substantiates:
- emissions and reductions that have been recorded pertain to the offset project activity;
- all emissions sources that should have been recorded were recorded accurately and appropriately;
- emissions and reductions quantification has been recorded transparently and appropriately;
- emissions and reductions have been recorded in the correct reporting period;
- emissions and reductions have been recorded in the appropriate category; and
- must have an auditable data management system.

The emission offset project developer must establish and apply quality management procedures to manage data and information. Written procedures must be established for each measurement task outlining responsibility, timing and location requirements. Verification requirements are outlined in the most current version of the Standard for Validation, Verification and Audit.

5.1. Project Monitoring

Monitoring requirements for CO₂-EOR enhanced oil recovery projects are addressed in two distinct categories: measurement for emission offset quantification purposes; and the monitoring activities that provide operational containment assurance. The first includes measurement activities required to quantify the net geological sequestration of CO₂ from the CO₂ capture, transportation and enhanced oil recovery injection activities that are outlined in this protocol. This first category applies to all EOR projects and the requirements are discussed further below.

The second category pertains to monitoring activities to ensure that the CO₂ injected into EOR schemes is permanently contained within the project/storage complex. Each EOR project must comply with the relevant Directives and Regulations and any specific monitoring requirements included in the EOR scheme approval issued by the AER.

Approvals to operate an EOR scheme are managed by the AER under section 39 of the Oil and Gas Conservation Act.

5.1.1. Project Monitoring Requirements for Quantification Purposes

Monitoring requirements include measurement of all relevant parameters to account for all supplemental energy inputs (e.g., fossil fuels, heat and electricity) required for the operations of the CO₂-EOR project scheme.

The project measurement devices should be off-the-shelf metering equipment such as gas or fluid flow meters, utility meters (gas and electricity) and gas analyzers. Any assumptions and contingency procedures must be documented. Meters must be maintained to ensure consistent operation with design specifications and must be calibrated according to AER requirements and quantification methodology requirements, otherwise according to manufacturer’s specifications. Reference AER Directive 017 Measurement Requirements for Oil and Gas Operations for guidance on calibration frequency for chain of custody meters. It is assumed that CO₂ chain of custody meters to have the same annual calibration requirements as natural gas chain of custody meters.

Below is additional detail for implementing a monitoring plan that takes into account the location, type of equipment, and frequency by which each variable is measured.

5.1.2. Project Monitoring Plan for Quantification Purposes

A monitoring plan must be established for all monitoring and measurement activities associated with the project. This monitoring plan will serve as a basis for third party assurance providers to confirm that the monitoring and measurement requirements have been met, and that consistent, rigorous monitoring and record keeping of measurement is ongoing at the emission offset project site. The monitoring plan must cover all aspects of monitoring and measurement for quantification of emissions contained in this protocol and must specify how data for all relevant parameters listed in Table 6 will be measured, collected and recorded. The monitoring plan is submitted as part of the offset project plan and must be available during any verification or reverification processes.

At a minimum the monitoring plan shall stipulate and include:
- The frequency of data acquisition;
- A record keeping plan;
- Identification of key instrumentation;
- The frequency of instrument calibration activities;
- The QA/QC provisions on data acquisition, management and record keeping that ensure monitoring, and the use and storage of data, is carried out consistently and with precision;
• The role of individuals performing each specific monitoring activity;

• Methods to measure and quantify the following data:
  o Energy inputs required to capture, dehydrate, compress, transport, inject and store CO₂ including:
    ▪ Direct fuel inputs; and
    ▪ Indirect energy inputs or other parasitic loads (e.g., heat or electricity consumption);

• Quantity and concentration of CO₂ sold to third parties including sufficient measurements to support data required;
  o Quantity and concentration of CO₂ injected into the EOR scheme;
  o Evidence that produced CO₂ is fully re-injected or otherwise accounted for; and
  o Regular leak detection and repair (LDAR Surveys) to quantify fitting, piping and equipment leaks.

Although some of the above data may not be required for the quantification of emissions, emission reductions, and geological sequestration, they must be tracked and reported for completeness purposes.

5.1.3. Gas Stream Flow Rate Requirements

Meter readings must be temperature and pressure compensated such that the meter output is set to standard reference temperatures and pressures. Estimates of CO₂ concentration and density are not acceptable;

Flow meters must be placed based on manufacturer recommendations:

• Flow meters should be located at the input to the gas transport equipment such that they are downstream of all capture and compression equipment to account for any fugitive losses or venting.; and

• Flow meters should be as close as possible to the injection wellheads to ensure accurate measurement of the injected volumes.

• Flow meters should not include re-injected fluid;

• Flow meters must be calibrated according to manufacturer specifications and AER requirements. Meters must be checked/calibrated at regular intervals according to these specifications and industry standards;

• When orifice meters are used, since pressure drop is measured and flow rate is calculated within the control logic, the density of the injection gas must be measured as per Table 6, using a third-party gas analysis. The measured density must be revised and entered into the control logic semi-annually.

• Chain of custody CO₂ flow meters must be calibrated in accordance with AER Directive 17 under the same calibration schedule as is advised for natural gas chain of custody meters, and

• Ownership transfer must be clearly documented for CO₂ transferred (third party injection activity).

It is also necessary to monitor the incremental energy inputs (fossil fuels, heat and electricity) required to operate the carbon capture, transport, injection, and re-injection facilities.

5.1.4. Monitoring and Reservoir Management Plan for Containment Assurance

Monitoring requirements, based on the characteristics of the reservoir and EOR scheme, are outlined by the AER in the CO₂-EOR scheme approval. It requires each enhanced oil recovery scheme to undertake specific monitoring and reservoir management activities to ensure the safe and permanent storage of CO₂. Risk factors for each project may be considered by the AER when determining the conditions of the scheme approval. General risk factors include financial failure, technical failure, management failure, regulatory and social instability, and natural disturbances. The following AER Directives outline specific conditions for measurement and monitoring:

• Directive 007 and 017: requirements for measuring and reporting the amounts of CO₂ injected;

• Directive 020: minimum requirements for well abandonment, testing to detect leakage and mitigation measures in the event of detecting leakage;

• Directive 051: requirements for injection and disposal wells, including the wellbore design, wellbore integrity logging, operational monitoring, and reporting requirements;

• Directive 065: application requirements for an Enhanced Recovery Scheme (such as CO₂-EOR) and a disposal scheme (such as CO₂ Disposal and Containment); and

• Directive 60: requirements for flaring, incinerating, and venting in Alberta at all upstream petroleum industry wells and facilities.

As required in the EOR scheme approval by AER, the annual progress report will provide containment assurance specific to the storage complex. The third party assurance provider must have access to the annual progress report submitted to the AER to ensure no CO₂ has escaped from any wellbores penetrating the project reservoir, and no
CO₂ migrated from the subsurface to the atmosphere or out of the storage complex, or if it has, that it has been fully accounted for. Hence, the overall objective of the monitoring plan is reservoir management for CO₂ containment assurance.

Where operational containment assurance is required by the AER, the EOR operator shall also provide to the Director, a subset of the submitted data in the form of a Containment Assurance Report (See Containment Assurance Report Template in Appendix D). It is based on measurement and engineering data that encompasses such items as; the results of reservoir management practices, including quantity and concentration of the injected, produced and re-injected CO₂. Additionally, any CO₂ moved outside of the EOR Scheme approval area must be reported in the Containment. Operational containment assurance may include results from other monitoring undertakings if other parameters are available from the EOR operator.

Containment assurance and reservoir management shall be reviewed periodically by the EOR operator, and the EOR operator must provide immediate notice to the Director, and take corrective action if changes occur that have the potential to adversely affect containment, which may include:

- Unexpected changes in project performance that have potential to influence associated storage of CO₂;
- Addition or abandonment of injection zones;
- Addition or abandonment of injector or producer wells;
- Anomalous change of injection-withdrawal ratio;
- Development of reservoirs which are located above or below the project reservoir;
- Discovery of CO₂ beyond the boundary of the CO₂-EOR storage complex or
- Removal or release of CO₂.

The CO₂-EOR Scheme approval requires the project operator to develop a termination plan for the CO₂-EOR project that specifies criteria for termination. This plan shall be developed any time after CO₂ injection begins, but must be developed prior to the termination of CO₂ injection at the scheme. The plan should specify:

- The termination process and anticipated timing;
- Plans for moving CO₂ from the storage complex;
- Monitoring consistent with AER requirements for CO₂ -EOR scheme closure;
- Corrective measures to address potential leakage;
- Provisional plans for site decommissioning, including plans for plugging and abandonment of wells and decommissioning of facilities.

Upon request, the emission offset project developer must demonstrate that a reservoir management plan for containment assurance is in accordance with any and all applicable AER, AEP, and Alberta Energy requirements. The emission offset project developer must also confirm that the project continues to operate in accordance with the conditions outlined in the operating license.

These results could be used to provide evidence of containment, including the supporting rationale.
5.2. Required Project Documentation

Documentation requirements for the emission offset project are as follows:

- The CO₂-EOR scheme number;
- Energy use records for capture, transport and CO₂-EOR scheme operations;
- Concentration and measurement records of injected, produced and reinjected CO₂;
- A completed Report Balance Sheet for CO₂ from Appendix C that includes:
  - The gross quantity of new CO₂ injected into the scheme, not including re-injected CO₂;
  - The project emissions for the current reporting period;
  - The quantity of previously injected CO₂ transferred to or from a Type 2 EOR Scheme (and associated transfers of Holdback amounts, if applicable);
  - The quantity of previously injected CO₂ moved from a Type 1 EOR Scheme (and forfeit of Holdback amounts, if applicable);
  - The net quantity in tonnes, of CO₂ stored by the project (CO₂ in place); and
  - The net Holdback quantity for the reporting period and the cumulative quantity.
- Documentation for project eligibility requires at a minimum:
  - The name and contact information of the emission offset project developer(s);
  - The CO₂-EOR scheme number;
  - Evidence of the CO₂ injection start date;
  - Evidence and explanation of ownership (for each emission offset project or subproject);
  - All applicable permits for project condition, where relevant;
  - A completed Reservoir Pressures Table (See Table 7) submitted to Director for approval to register a project.
  - A suitable reservoir management plan as defined by AER requirements;
  - Evidence that each project results in net geological sequestration located in Alberta including legal land location or GPS coordinates of the site via the inventory or a spatial locator; and
  - Project quantification and calculations.

Documentation for the Baseline condition requires at a minimum:

- The total emissions for all SSRs included in the baseline;
- Calculations applied to measured baseline data and justifications for any deviations from those calculations;
- The measured baseline data for all baseline condition SSRs included in the quantification as recorded from the measurement device before calculations are applied.

Documentation for the Project condition requires at a minimum:

- For each project year, the total emissions accounted under each included source/sink;
- Evidence of timing of project implementation;
- For each project year, calculations applied to measured project data and justifications for any deviations from required measurements calculations specified in Table 6;
- For each project year, the measured project data as recorded from the measurement device, before calculations are applied.
## Table 7: Reservoir Pressure Table – Summary of CO2-EOR Scheme Approval Values for the Offset Project

<table>
<thead>
<tr>
<th>Item</th>
<th>Reservoir Pressure Name</th>
<th>Type 1 Scheme Approval (kPa)</th>
<th>Type 2 Scheme Approval (kPa)</th>
<th>Comments/Data Source is CO2-EOR Scheme Approval</th>
</tr>
</thead>
<tbody>
<tr>
<td>a.</td>
<td>Initial reservoir pressure (P_i)</td>
<td>____</td>
<td>____</td>
<td>CO2-EOR Scheme Approval</td>
</tr>
<tr>
<td>b.</td>
<td>Reservoir pressure prior to start of the CO2-EOR scheme (P_{prior})</td>
<td>____</td>
<td>____</td>
<td>CO2-EOR Scheme Approval or Application</td>
</tr>
<tr>
<td>c.</td>
<td>Minimum Miscibility Pressure (MMP)</td>
<td>____</td>
<td>____</td>
<td>CO2-EOR Scheme Approval for CO2 in oil</td>
</tr>
<tr>
<td>d.</td>
<td>Minimum reservoir injection pressure (P_{inj})</td>
<td>____</td>
<td>____</td>
<td>No production allowed if pressure drops below this value</td>
</tr>
<tr>
<td>e.</td>
<td>Maximum injection pressure (P_{max})</td>
<td>____</td>
<td>____</td>
<td>No production allowed if pressure increases above this value</td>
</tr>
<tr>
<td>f.</td>
<td>Maximum reservoir pressure at cessation of oil production under the approved CO2-EOR scheme (P_{end})</td>
<td>____</td>
<td>____</td>
<td>CO2-EOR Scheme Approval</td>
</tr>
<tr>
<td>g.</td>
<td>Required reservoir pressure at abandonment (P_{abandon})</td>
<td>____</td>
<td>____</td>
<td>CO2-EOR Scheme Approval may say equal to or below</td>
</tr>
</tbody>
</table>
5.3. Record Keeping and Project Archives

Alberta Environment and Parks requires that emission offset project developers retain records as per the requirements in section 31(6) of the Technology Innovation and Emission Reduction Regulation. Where the emission offset project developer is different from the person implementing the activity, as in the case of an aggregated emission offset project, the individual projects and the aggregator must both maintain sufficient records to support the offset project. If project ownership changes, sufficient records to support the offset project must be provided to the new owner. The following records must be collected and disclosed to the third party assurance provider and/or government third party assurance provider upon request.

Record keeping requirements:

Raw baseline period data, independent variable data, and static factors within the measurement boundary;

- A record of all adjustments made to raw baseline data with justification;
- All analysis of baseline data used to create mathematical model(s);
- All data and analysis used to support estimates and factors used for quantification;
- Metering equipment specifications (model number, serial number, manufacturer’s calibration procedures/field meter proving method);
- A record of changes in static factors along with all calculations for non-routine adjustments;
- All calculations of greenhouse gas emissions/reductions and emission factors;
- Measurement equipment maintenance activity logs;
- Measurement equipment calibration records or field meter proving records. Flow meters should be maintained and calibrated according to manufacturer specifications and in accordance with the more stringent of the AER requirements and the Quantification Methodologies under Alberta greenhouse gas regulations, and the Specified Gas Reporting Regulation (which requires a calibration frequency of once every 3 years).
- For meters that cannot be calibrated or proved in the field, documentation must be provided by the emission offset project developer or the meter manufacturer to substantiate the use of an alternative meter maintenance program;
- All AER approvals and requirements; and
- All verification records and audit results.

In order to support the third party verification and any supplemental government reverifications, the emission offset project developer must put in place a system that meets the following criteria:

- All records must be kept in areas that are easily located;
- All records must be legible, dated and revised as needed;
- All records must be maintained in an orderly manner;
- All documents must be retained in accordance to regulatory requirements;
- Electronic and paper documentation are both satisfactory; and
- Copies of records should be stored to prevent loss of data.
- Attestations are not considered sufficient evidence that an activity took place and do not meet verification requirements.
5.4. Quality Assurance/Quality Control Considerations

Quality Assurance/Quality Control are applied to add confidence that all measurements and calculations have been made correctly. These include, but are not limited to:

- Protecting monitoring equipment (sealed meters and data loggers);
- Protecting records of monitored data (hard copy and backup electronic storage);
- Checking data integrity on a regular and periodic basis (manual assessment, comparing redundant metered data, and detection of outstanding data/records);
- Comparing current estimates with previous estimates as a reality check;
- Providing sufficient training to operators to perform maintenance and calibration of monitoring devices or contract with qualified third parties;
- Establishing minimum experience and requirements for operators in charge of project and monitoring;
- Ensuring that the changes to operational procedures continue to function as planned and achieve net geological sequestration;
- Ensuring that the measurement and calculation system and greenhouse gas reduction reporting remains in place and accurate;
- Checking the validity of all data before it is processed, including emission factors, static factors and acquired data;
- Performing recalculations of quantification procedures to reduce the possibility of mathematical errors;
- Storing the data in its raw form so it can be retrieved for verification;
- Recording and explaining any adjustment made to raw data in the associated report and files; and
- Developing a contingency plan for potential data loss.
6. References


Canadian Standards Association (CSA). Z741 Geological Storage of Carbon Dioxide, December 2012

Det Norske Veritas (DNV). CO₂QUALSTORE Guidelines for Selection and Qualification of Site and Projects for Geological Storage of CO₂, February 2010


Environmental Protection Agency (EPA). Proposed Rule Subpart RR—Carbon Dioxide Injection and Geologic Sequestration, March 2010


International Energy Agency. Monitoring and Reporting Guidelines for Injection and Storage


International Organization for Standardization. ISO 27915:2017 Carbon dioxide capture, transportation and geological storage - Quantification and verification, 2017

International Organization for Standardization. ISO 27916:2019 Carbon dioxide capture, transportation and geological storage — Carbon dioxide storage using enhanced oil recovery (CO₂EOR), 2019


World Resources Institute (WRI). Guidelines for Carbon Dioxide Capture, Transport, and Storage, October 2008
Guidance for the Injection of CO₂ by Multiple Networks
The following provides guidance for projects in which CO₂ is being transported for use in CO₂-EOR schemes. Gas flow/quantity measurement and CO₂ concentration measurement/sample points must be carefully considered in complex/multiple networks. Scenarios 1 through 4 depict the fluid flow measurement and CO₂ concentration measurement/sample points in a variety of project configurations from simple to more complex.

Scenario 1: Single Capture Single Storage

Must measure CO₂ concentration or gas composition (C). The sample point may be downstream of capture or at the storage location (injection well) upstream of the location where the produced gas stream is reinjected. Must measure gas quantity (F) at storage location (injection well) upstream of the location where the produced gas stream is re-injected.

Scenario 2: Single Capture Multiple Storage

Must measure CO₂ concentration or gas composition (C) at either at the point of capture or points of storage. Not required to measure both locations. Must be measured upstream of the location where the recycle stream is reinjected. Must measure gas quantity (F) at the point of storage upstream of the produced gas re-injection. Not required to measure gas quantity at inlet of Transport unless gas quantity at each storage location is not available. Must have n-1 measured gas quantities in all cases. Measured CO₂ concentration at the inlet to transport will be equal to the CO₂ concentration at storage.
Quantification Protocol for Enhanced Oil Recovery

**Scenario 3 - Multiple Capture Single Storage**

Indicates concentration calculated based on weighted average of incoming streams

Must measure CO₂ concentration or gas composition at each capture site upstream of comingling. Must measure gas quantity at each capture site upstream of comingling. Allowable to calculate the CO₂ concentration of the comingled stream based on the weighted average of the incoming streams to be comingled in a single variable, mass balance equation. Must measure gas quantity at storage upstream of produced gas re-injection. The CO₂ concentration at storage is the calculated concentration of the comingled stream.

If using a weighted average method, it must be completed downstream of each new capture site that is added to the network.

**Scenario 4 - Multiple Capture Multiple Storage Scenario**

Indicates concentration calculated based on weighted average of incoming streams

Must measure CO₂ concentration or gas composition at each capture site upstream of comingling. Must measure gas quantity at each capture site upstream of comingling. Allowable to calculate the CO₂ concentration of the comingled stream based on the weighted average of the incoming streams to be comingled in a single variable, mass balance equation. Weighted average calculation must be completed downstream of each new capture site that is added.

Measure gas quantity at storage upstream of re-injection. CO₂ concentration at injection is the calculated concentration of the comingled stream or measured upstream of injection. When there is a single unknown, the concentration must be measured at each capture site upstream of where the capture stream comingles.

In addition to careful consideration to sample points and measurement, in complex networks, emission offset project developers must demonstrate that all SSs are properly accounted for and must ensure all emissions have been included and have not been double counted. For a complex CO₂ system or network, the emissions from that network must be included in Quantification Protocol for Enhanced Oil Recovery.
the project condition using a system emission factor or a proration of emissions across the network. The emission offset project developers must provide verifiable justification for the method and values used to determine the system emission factor used.

In the multiple capture multiple storage scenarios, details of a full system wide allocation of emissions for each project must be provided for verification/reverification. To protect commercially sensitive information, each emission offset project developer will receive a report with the relevant details (mass flow, CO₂ concentration and allocated carbon emissions for the pipeline system) for their specific project as required for verification/reverification in compliance with Standard for Validation, Verification and Audit. The remainder of the system measured data may be presented to the emission offset project developer as one unspecified group rather than delineated by each of the other companies within the system.
Project Emissions Prior to Tie-in Point
Project emissions prior to the tie-in point are described as any emission occurring before the pipeline splits to deliver the CO₂ to the multiple developers. Project emissions prior to the tie-in point are characterized by all the emissions associated with capturing CO₂.

To properly account for all project emissions, emission offset project developers must proportionally allocate all project emissions prior to the tie-in point across all developers. Each developer must account for their allocation of project emissions. This results in an equal distribution of the associated project emissions prior to the tie-in point depending on the quantity of CO₂ injected by each developer.

For example, if Developer A injects 60% of the captured CO₂ and Developer B injects the other 40%, the upstream project emissions associated with the captured CO₂ are allocated proportionally to each developer. In this example, Developer A is allocated 60% of the total project emissions prior to the tie in point. Developer B is allocated 40% of the total project emissions prior to the tie in point.

Project Emissions Subsequent to Tie-In Point
Project emissions subsequent to the tie-in point are described as any emission occurring after the pipeline splits to deliver the CO₂ to the multiple developers. Each developer must account for individual project emissions associated with CO₂ injection.

Requirements for Complex CO₂ Networks

- Capture facility operators will measure the CO₂ concentration and quantity of gas at the capture site and will measure all data points as required to determine the emissions of the capture operation.
- Transport (pipeline operator) will maintain an auditable and verifiable custody transfer system tracking mass of CO₂ accepted onto the pipeline and delivered to each major off taker.
- Transport (pipeline operator) will measure all data points required to quantify the emissions related to transport operations.
- Storage (CO₂-EOR) operators will measure all data points required to quantify the emissions of the CO₂-EOR operations.
APPENDIX B: Guidance for Estimating Emissions from Subsurface Equipment and EOR Subsurface Operations

For the quantification of $P_{22}$ Emission from Subsurface to Atmosphere, the quantity of emissions leaked from the subsurface equipment or EOR Subsurface operations to atmosphere for each of the leakage events must be estimated with a maximum overall uncertainty of ±7.5% over the reporting period. If the amount of emissions leaked can be estimated within an uncertainty range of ±7.5%, the estimated figure is reported and used. If the overall uncertainty exceeds ±7.5%, the following adjustment must be used:

$$\text{CO}_2, \text{Reported [tonnes CO}_2] = \text{CO}_2, \text{Quantified [t CO}_2] \times (1 + (\text{Uncertainty System [\%]}/100))$$

Where:
- CO$_2$, Reported: Amount of CO$_2$ to be included into the annual emission report with regards to the leakage event in question;
- CO$_2$, Quantified: Amount of CO$_2$ determined through the used quantification approach for the leakage event in question; and
- Uncertainty System: The level of uncertainty which is associated to the quantification approach used for the leakage event in question.

Adapted from two sources:
1) IEA presentation, on ‘Monitoring and Reporting Guidelines for Injection and Storage’, Implications of the Inclusion of Geological Carbon Dioxide Capture and Storage as CDM Project Activities, https://cdm.unfccc.int/EB/050/eb50annagan1.pdf which says:
   “Maximum +/-7.5% uncertainty, if exceeded then add ‘uncertainty Adjustment’”
2) CDM UNFCC says: It is important to be conservative and so err on the side of overestimation rather than underestimation. An example of how to apply this conservative principle is provided by the EU ETS Monitoring and Reporting Guidelines for CCS63. In these, if the uncertainty is above a specified level for the measured emissions of seepage, these measured emissions will be multiplied by an “uncertainty supplement”. In the EU case this is set for a maximum uncertainty of 7.5%, and if this cannot be achieved then measured emissions are multiplied by an uncertainty supplement (which is added to the measured emissions).
APPENDIX C: Report Balance Sheet for CO₂

A completed balance sheet must be included with every project report and the final report for requesting release of holdback.

**CO₂-EOR Offset Project Name:**
**CO₂-EOR Offset Project Identifier:**
**Reporting Period Start:**
**Reporting Period End:**

<table>
<thead>
<tr>
<th>CO₂ Inventory</th>
<th>Prior Cumulative (tonnes CO₂)</th>
<th>This Reporting Period (tonnes CO₂)</th>
<th>New Cumulative (tonnes CO₂)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO₂ In Place, resulting from the emission offset project</td>
<td></td>
<td>(place period delta here)</td>
<td></td>
</tr>
<tr>
<td>Newly Captured CO₂ Injected Quantity</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO₂ Transfers from this project for Type 2 only Transferred to:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Associated Holdback transfer from this Type 2 project, if applicable Transferred to:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CO₂ Transfers to this project Transferred from:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Associated Holdback transfer to this project, if applicable Transferred from:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Project Emissions</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reversals Post Project</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Emission Offsets</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Uncredited Volume (either prior to project or post project)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Holdback Amount (tonnes CO₂e)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Holdback Balance (total holdback less transfers out plus transfers in)</td>
<td></td>
<td></td>
<td>(place period delta here)</td>
</tr>
<tr>
<td>Discount</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
APPENDIX D: Containment Assurance Report Template

A completed Containment Assurance Report is required to be submitted by the emission offset project developer to the Director each calendar year, including each year in the post crediting period (it is not required to be part of project report submitted to the Registry). The time period should match the Annual Progress Report submitted to the AER. The AER may also flag any non-compliance events to Alberta Environment and Parks.

Alberta regulation sets out that the geological sequestration of carbon dioxide must be permanent. The purpose of this Containment Assurance Report is to demonstrate that sequestration from an Enhanced Oil Recovery scheme (and emission offset project) is permanent during the offset crediting period and for the necessary period after the offset crediting period. This report will identify an event that resulted in non-permanent sequestration (i.e. reversal, removal, etc.) of the CO₂.

Events that could potentially result in non-permanent sequestration of carbon dioxide include:

1) Migration of CO₂ beyond the permitted geology;
2) Mechanical integrity/well failure/integrity of existing wells in the field;
3) Production of CO₂ to surface and venting to atmosphere;
4) Production of CO₂ to surface and diversion to flare;
5) Fugitive emissions of CO₂; and,
6) Production of CO₂ and transfer out of the scheme approval area.

1.0 Project Identification:

Reporting on Calendar Year:

Project Name:
Project Developer:
Prepared by:
Submission Date:

1.1 Project Name/Project ID and EOR Scheme Approval Number:

1.2 Project Type (Type 1 or Type 2):

2.0 Assurance of Containment:

2.1 Mass of CO₂ Injected:

Provide evidence of total new CO₂ injected over the last calendar year, including a table with the monthly compositions, volumes, the weighted average composition and quantity injected.

Provide evidence of the net tonnes of CO₂ injected over the last calendar year.

Describe how any recycled CO₂ is measured and accounted for in the net CO₂ injected over the last calendar year.

Indicate Directives and data sources from which this evidence is provided.

Conclusion

The total injected CO₂ for the calendar year is ________ tonnes.

2.2 Migration of Subsurface CO₂

Describe the Permitted Geologic Boundaries and the CO₂ Plume Extent.

Indicate Directives and data sources from which this evidence is provided (for example, Directive 065, Petrinex).

Conclusion

Explain whether the CO₂ plume is extending beyond the permitted geology, and if it is, provide a quantification of CO₂ volumes that extend outside the permits.

2.3 Reporting of CO₂ Vented, Flared, and Fugitive Emissions

Quantification Protocol for Enhanced Oil Recovery
Provide a summary of the emission offset project developer’s approach to inventorying, quantifying and reporting vented, flared and fugitive emissions. Include a description of any tracking software used and calculation methods used to to quantify emissions.

2.3.1 Reporting of CO₂ Vented

Provide evidence of any CO₂ vented in the calendar year.
Indicate Directives and data sources from which this evidence is provided.

Conclusion
The total quantity of CO₂ vented during the calendar year from the _____ Project is _____ tonnes.

2.3.2 Reporting of CO₂ Flared

Provide evidence of all CO₂ flared and all supplemental fuel flared during the calendar year in units of tonnes CO₂e.
Indicate Directives and data sources from which this evidence is provided.

Conclusion
The total quantity of CO₂ flared during the calendar year was ______ tonnes CO₂e.
The total quantity of supplemental fuel flared during the calendar year was ______ tonnes CO₂e.

2.3.3 Reporting of Fugitive Emissions of CO₂

Provide evidence of any CO₂ from fugitive emissions in the calendar year in units of tonnes CO₂e.
Indicate Directives and data sources from which this evidence is provided.

Conclusion
The total fugitive emissions of CO₂ during the calendar year is ____ tonnes CO₂e.

2.4 Reporting of CO₂ Transferred outside of scheme area

Provide the individual quantities of CO₂ transferred out of the approved EOR Scheme Area (permitted geology) during the calendar year, and where the CO₂ was transferred to (ie., a specific EOR scheme/offset project, another facility, etc.).
Provide the total quantity of CO₂ transferred.

Conclusion
There has been an individual transfer of ____tonnes CO₂ out of the EOR Scheme Area, which is also the EOR offset project, and moved to ________________.

There has been a second individual transfer of ____tonnes CO₂ out of the EOR Scheme Area, which is also the EOR offset project, and moved to _________________. Etc.

The total transfer of ______tonnes CO₂ out of the EOR Scheme Area, which is also the EOR offset project, during the calendar year.

This has been accounted for as ________________ (ie., a holdback transfer, a forfeit of holdback or a reversal) by the offset project developer in the most recent project report dated yyyy/mm/dd and in the CO₂ balance sheet submitted as part of the offset project report.

3.0 Containment Assurance Conclusion:

In the calendar year, yyyy/mm/dd – yyyy/mm/dd, covered by this Containment Assurance Report:

There were ________ tonnes of new CO₂ injected into the project area.
There were _________ tonnes of CO₂ released from the project area via subsurface migration out of permitted geology, removed from the project area via production to surface and flared, vented or as a fugitive emission.

There were _________ tonnes of CO₂ transferred out of the EOR Scheme Area.