DRAFT Quantification Protocol for CO_2 Capture and Permanent Geologic Sequestration

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Disclaimer:

Regulation and the legislation for all purposes of interpreting and applying the law. In the event that there is a difference between this document and the Technology Innovation and Emissions Reduction regulation, the Technology Innovation and Emissions Reduction regulation or the legislation prevail.

All Quantification Protocols approved under the Technology Innovation and Emissions Reduction regulation are subject to periodic review as deemed necessary by the Department, and will be periodically re-examined to ensure methodologies and science continue to reflect best-available knowledge and best practices.

Any comments or questions regarding the content of this document may be directed to:

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Contents

List of Tables

List of Figures

Related Publications

- *Emissions Management and Climate Resilience Act (the Act)*
- *Mines and Minerals 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 Enhanced Oil Recovery

1.0 Emission Offset Project Description

Carbon dioxide (CO_2) is emitted as a by-product in many industrial production processes and as a result of fuel combustion. This CO_2 may be captured for other uses, or released directly to the atmosphere. Capturing CO_2 emissions and transferring them to a geologic storage zone(s) suitable for permanent sequestration results in a permanent reduction in CO_2 emissions.

Carbon capture and storage projects applicable under this protocol consist of three main components:

- CO_2 capture infrastructure, which includes a process modification to a facility to capture vented CO_2 emissions. The carbon capture facility may be separate from the emission source facility, and typically uses a chemical solvent CO_2 capture technology;
- A CO_2 pipeline and/or other means of transportation to transport CO_2 from the capture facility to the injection well(s); and
- Disposal of CO_2 through injection wells and into a permitted geologic storage zone(s) suitable for permanent sequestration.

Emission offset project developers using this protocol should have familiarity with CO_2 capture and storage projects and greenhouse gas quantification methodologies.

1.1 Emission Offset Protocol Scope

This protocol is for quantifying the net geological sequestration of carbon dioxide that meets the requirements set out in section 19(2) of te Technology, Innovation and Emissions Reduction Regulation. The sequestration must not be subject to a carbon price outside of the federal Clean Fuel Regulations. Project activities which are in scope may include the capture of New CO_2, and the compression, transport, injection, and permanent net geological sequestration of CO_2. A process flow diagram for a typical carbon capture and sequestration (CCS) project is shown in Figure 1.

This protocol does not apply to CCS activities using CO_2 enhanced oil recovery (EOR), or acid gas injection schemes associated with sour natural gas processing operations. Emission offset project developers with CO_2 EOR projects should refer to the applicable Alberta approved quantification protocol.

Protocol Approach
This protocol applies to CCS emission offset projects where captured CO_2 is received from a large emitter or opted-in facility regulated under the provincial greenhouse gas regulation (GHG) Regulation, which would otherwise have been emitted to atmosphere and under the project condition is injected into an approved CO_2 sequestration scheme. This protocol provides the methodology for emission offset project developers to follow, and outlines the requirements for measurement, monitoring, quantification and verification of net geological sequestration. A large emitter must report the captured CO_2 as part of their Total Regulated Emissions (TRE).

Baseline Condition
Baseline emissions are determined using a projection-based baseline to quantify the emissions that would have otherwise been emitted to the atmosphere in the absence of the offset project. The baseline emissions are quantified using the metered quantity of CO_2 injected into the targeted geologic storage zone(s) suitable for permanent storage less any CO_2 injected that originates from within the project boundary. Baseline sources and sinks are shown in .

The only greenhouse gas eligible under the baseline condition of this protocol is CO_2. The sequestration of methane or nitrous oxide is not eligible for emission offsets.

Project Condition
Project emissions may include those from the CO_2 capture, compression, transport, and injection activities associated with injecting CO_2 into a targeted geologic storage zone(s) for permanent sequestration. CCS projects primarily sequester CO_2. However, the CO_2 stream may include several impurities such as CH_4, N_2O, H_2S, N_2, etc. A wide range of light hydrocarbons and/or sulfur-based gases may be emitted as a result of CO_2 capture, compression, transport, and injection.

Some of the impurities may be greenhouse gases other than CO_2. The greenhouse gases that must be included in the project condition include all related emissions of CO_2, CH_4, and N_2O, as per the quantification section of this protocol.

Refer to the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports for the associated global warming potential of these gases.

Emission Offset Project Developer
The CO_2 capture, compression, transport and net geological sequestration may or may not be conducted by the emission offset project developer. It is likely that different entities may conduct each of the project activities. Each entity must maintain records in accordance with section 5.3. Records must be available for verification or reverification of the emission offset project and must also be made available 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 is the emission offset project developer's responsibility to work with all entities conducting the project activities to obtain access to all records, data and equipment that may be required for monitoring, measurement, quantification and verification. The emission offset project developer must also retain all project records according to the requirements in the Regulation, the Standard and this protocol.

CO_2 Capture Entity
The CO_2 capture entity is responsible for the equipment, and is the originator of data records, related to CO_2 capture that may be required for quantification and verification. The data records may include evidence of captured CO_2 quantities, including concentration and composition, and of any heat, power or fuel used on-site for CO_2 capture. The capture entity may also be the owner of compression equipment and responsible for all records related to compression for quantification and verification.

Transport Entity
The transport entity is responsible for the equipment and is the originator of data records related to CO_2 compression and transportation that may be required for quantification and verification. This may include evidence of delivered CO_2 quantities, including concentration and composition and of any heat, power or fuel used on-site or fuel used to transport CO_2.

Transportation of CO_2 via non-pipeline mechanisms can apply through the approval of a deviation request from the Director. The request must outline how all emissions associated with the transport system will be measured and quantified.

Sequestration Entity
The sequestration entity is responsible for the equipment, and is the originator of data records, related to CO_2 injection, 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 CO_2 composition, injected CO_2 quantities, and records for any heat, power or fuel used on-site.

1.2 Offset Crediting Period

The offset crediting period for this activity is 20 years, with the possibility of ongoing 5-year extensions. The criteria for project extension, is set out in the Standard for Greenhouse Gas Emission Offset Project Developers.

The reporting periods must be contiguous for the duration of the offset crediting period.

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, which may be granted if the Director is satisfied the project developer has ensured the project boundary, CO_2 source and eligibility requirements will be met. The emission offset project developer's submission requesting the Director's approval must provide evidence demonstrating the project meets the following requirements:

1. 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 below, any flexibility mechanism to be utilized, any plan for alternate sequestration or transfers of the CO_2 outside of the project boundary, the D065 Scheme Approval for the activity, and an explanation of any special conditions that may apply to the activity.
2. The emission offset project developer provides evidence to demonstrate that the CO_2 is captured from a large emitter or opted-in facility under the Regulation unless otherwise approved by the Director. This is demonstrated by actual CCS project schematics and by compliance with the measurement requirements set forth in the quantification section of this protocol.
3. The CCS scheme must have obtained approval from the Alberta Energy Regulator (AER) under Directive 065 – Resources Applications for Conventional Oil and Gas Reservoirs and Section 39 of the Oil and Gas Conservation Act, and meet the requirements outlined under Directive 051: Injection and Disposal Wells –Well Classifications, Completions, Logging and Testing Requirements.
4. The emission offset project boundary must be clearly described, which includes the emissions system; the CO_2 sources and if they are inside or outside the project boundary, the transportation system, the targeted geologic storage zone(s) and the surface locations. A clear delineation of where the large emitter or opt-in facility stops and the emission offset project starts must be part of the description.

   The physical boundary for injection will be equivalent to the boundary set out in the D065 Scheme approval. The emission offset project boundary includes:
   - One or more CO_2 D065 Scheme approval (outlining the part of the project boundary corresponding to the injection/sequestration entity), and the approved targeted geologic storage zone(s), and
   - The capture and transportation elements of the project unless the associated emissions are accounted for by the regulated facility from which the CO_2 is being captured.
5. The project must have obtained all required operating permits under 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 that employ alternate technologies for CO_2 capture, transport, injection, or use technologies and processes other than those commercially available and outlined in this protocol.

1.4 Flexibility Mechanisms

This protocol provides the following flexibility mechanisms to the emission offset project developer. Any usage of a flexibility mechanism must be documented in the project report and project plan with justification and 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: Direct Air Capture facility as emissions source
This flexibility mechanism allows project developers to source CO_2 from direct air capture (DAC) facilities in Alberta. 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 CO_2 per year. Project developers using this source of CO_2 must quantify all vented, flared and fugitive emissions upstream of the injection meters except for emissions of the captured CO_2. Applicable material inputs/consumable must also be considered during quantification. The quantification must meet the same rigor as for large emitters, as outlined in the TIER Quantification Methodology

Flexibility Mechanism 2: Project Boundaries
Where the project boundaries differ from the process flow diagram for the project condition (see), Director approval must be obtained prior to project initiation on the registry. This ensures all direct and indirect emissions associated with the offset project are accounted for in the offset project plan or the compliance reporting for the associated large emitter(s) or opt-in(s) as intended. Proponents are referred to the most recent version of Standard for Greenhous Gas Emission Offset Project Developers for information regarding deviations from protocols.

Flexibility Mechanism 3: Limiting impact of reversals to TIER credits through increased discount factor
If a project developer prefers to limit the reversal true-up liability for the crediting and post crediting pre-closure project stages to a maximum total of three-year injected volume based on the average annual injection over the course of the crediting period(s), they can elect to apply an increased discount factor.

The maximum liability will be calculated as the annual average of CO_2 injected (B1) over the life of the crediting period, multiplied by three years.

Under this flexibility mechanism project developers are still required to apply the discount factor to injected CO_2 (B1) outlined in 1.5.3 to cover post-closure reversals from start of project to the end of year 3. Beginning in year 4, the applied discount factor will increase to 0.01 and will be discounted until the issuance of a closure certificate.

Discounted injected CO_2 will be accounted for as ‘retired to atmosphere’.

Flexibility Mechanism 4: Tenure Mechanism without liability transfer
In some cases, CCS project developers may be granted sequestration rights from Energy and Minerals through a tenure mechanism that does not permit the transfer of liability under the *Mines and Minerals Act* through the issuance of a closure certificate. While this does not preclude a project

from generating emission offsets under this protocol, the project developer must receive written approval from the Director and adhere to the following conditions:

- Apply flexibility mechanism 3 to their projects and apply the increased discount factor beginning in year 4.
- No further true-up liability obligations associated with climate liability will be required when the project developer can demonstrate the following:
  - Evidence is provided to the Director that all project wells associated with the emission offset project have been abandoned in accordance with applicable well abandonment regulations, directives, and rules; and
  - 20 years have passed since the date the last project well was abandoned; and
  - A post-crediting, pre-closure reversal as defined in section 1.5 has not occurred since the last well was abandonment.

For projects utilizing this flexibility mechanism, in lieu of closure certificate issuance, the conditions for post-closure liability transfer will be used to differentiate between project life cycle stages as they relate to a reversal under section 1.5.

1.5 Reversals

A reversal is an accidental or intentional release or removal of CO_2 from the targeted geologic storage zone(s) during or after the offset crediting period. An accidental reversal meets the following criteria:

- The AER determines a loss of containment has occurred under the emission offset project's D065 scheme approval,
- The loss of containment cannot be remediated, and
- An expert investigation determines the CO_2 that is subject of the loss of containment will foreseeably leak into the atmosphere within 100 years of the occurrence of the loss of containment.

Emissions associated with a reversal that can be remedied must be accounted for, as per sections 1.5.1, 1.5.2 and 1.5.3, whichever applies.

The timing of a reversal will affect how the reversal is accounted for. True-up processes will consider the last emissions injected, to be the first emissions released as part of a reversal. In cases where multiple emission offset projects are injecting into shared pore space, the same last-in first-out accounting will be applied, causing the reversal to be apportioned to the appropriate offset projects until it is fully accounted for.

Distinct time frames for reversals are considered as follows:

1. Net Reversal –A reversal that occurs during any offset reporting period and results in a negative greenhouse gas statement.
2. Post-Crediting, Pre-Closure Certificate Reversal – A reversal that occurs after the end of the offset crediting period, but prior to the issuance of a closure certificate.
3. Post-closure Reversal – A reversal that occurs after a closure certificate has been granted to the project developer by the Crown.

For projects utilizing flexibility mechanism 4, in lieu of closure certificate issuance, the conditions for post-closure liability transfer will be used to differentiate between project life cycle stages as they relate to a reversal.

Project developers will not require true-up action related to a reversal stemming from a terrorist act or natural disaster.

1.5.1 Net Reversal

A net reversal occurs when project emissions are greater than baseline emissions during any reporting period, resulting in a negative greenhouse gas statement. A net reversal may also occur where project emissions are greater than net reductions as a result of a low volume of injected CO_2 during a reporting period. Emissions from a reversal (P20) must be quantified in any reporting period according to the methods outlined in this quantification protocol. If there is an event that occurs during the reporting period and emissions from P20 result in a negative greenhouse gas statement this is considered a net reversal.

Once the offset project report with a negative statement is submitted to the Registry, the project developer must notify the director of the negative statement and remove emission offsets from a previous reporting period by following the error correction process set out in the Standard for Greenhouse Gas Emission Offset Project Developers. If the emission offsets that are removed were used to meet a compliance obligation, the large emitter must follow the true-up process set out in the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports.

The reporting periods must be contiguous for the duration of the offset crediting period.

1.5.2 Post-Crediting, Pre-Closure Certificate Reversal

If a reversal occurs after the end of the offset crediting period but prior to closure certificate issuance, it will be considered a post-crediting, pre-closure certificate reversal. During the closure period, the offset project developer will not be submitting regular offset reports. To ensure the department continues to have assurance of containment, offset project developers must submit an annual containment assurance report to the Director. A containment assurance template is provided in Appendix C and must be used by the project developer.

Reversals of carbon dioxide during the closure period must be reported on the containment assurance report and will result in the Director cancelling invalid emission offsets. If the emission offsets that are invalid were used to meet a compliance obligation, the regulated facility must follow the true-up process set out in the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports.

1.5.3 Post-Closure Reversal

Once a closure certificate has been issued, the risk for a reversal is considered to be low. To mitigate remaining risk or uncertainty with post-closure reversal, the emission offset project developer is required to apply a discount of 0.005 to injected CO_2 (B1) during the quantification of each greenhouse gas statement during the offset crediting period. This discount is applied to the projection-based baseline and considered 'retired to the atmosphere'.

If a post-closure reversal occurs, the Director will not cancel emission offsets related to the post-closure reversal, and no action is required from the project developer or large emitter who used the emission offsets for TIER compliance.

1.6 Removal Credits

A removal activity involves a removal of CO_2 from the atmosphere. Under this protocol, CO_2 captured from a direct air capture facility (under flexibility mechanism 1) or CO_2 captured from a biogenic source that is permanently sequestered in a targeted geologic storage zone(s) capable of permanent storage, may be classified as a CO_2 removal credit on the Alberta Emission Offset Registry under this protocol.

The emission offset project developer must state their intent to generate removal credits by written request to the Director, under section 1.3.1 and outline how they have met, or will meet, the following requirements:

1. The project must capture CO_2 from a direct air capture facility or capture biogenic CO_2 (i.e. biomass energy with CCS).

2. Prior to seeking Director approval, the project must complete a validation that supports the project design and ensure completeness of accounting and application of this protocol.
3. For biogenic CO_2, the project must determine the biogenic portion of the CO_2 emissions using ASTM D6866-16 "Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis".
   a. Analysis must occur at least every three months if the biogenic CO_2 is within a mixed stream at the point of metering upstream of co-mingling.
   b. Analysis must occur at least once every two years if the biogenic CO_2 is not within a mixed stream at the point of metering upstream of co-mingling.
4. Allocate total emission offsets between removal and non-removal types using a weighted average of the composition analysis.
5. A verifier must confirm assertions of claimed emissions reductions associated with the generation of removal credits and non-removal credits.

CO_2 removal credit types on the Alberta Emission Offset Registry will carry no additional compliance benefit and are subject to all requirements and restrictions of an emission offset under the regulation.

1.6 Glossary of Terms

Alberta Electricity Grid	A system of conductors and other equipment 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 or ambient CO_2 is separated and captured for eventual injection as part of a CO_2 sequestration scheme.
Closure Certificate	Closure certificate as defined in the *Mines and Minerals Act*.
Closure Period	For the purposes of this protocol, the closure period is the period of time between the end of emission offset crediting period and the issuance of a closure certificate. For projects with tenure that does not permit the issuance of a closure certificate, the closure period is the period of time between the end of the emission offset crediting period and all conditions under Flexibility Mechanism 4 being met.
Containment Assurance	Demonstration that the features and geologic structures relied on for the CO_2 sequestration activity are adequate to provide safe, long-term containment of CO_2.
Directive 007	*Volumetric and Infrastructure Requirements*. 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. Referenced as D007.
Directive 017	*Measurement Requirements for Oil and Gas Operations*. 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). Referenced as D017.
Directive 020	*Well Abandonment*. 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. Referenced as D020.
Directive 051	*Injection and Disposal Wells: Well Classifications, Completion, Logging, and Testing Requirements*. 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. Referenced as D051.
Directive 065	*Resources Applications for Oil and Gas Reservoirs*. 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 or to operate a sequestration scheme. Referenced as D065.
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)	To mitigate remaining risk or uncertainty with post-closure reversal, the emission offset project developer is required to apply a discount factor to injected CO_2 (B1) during the quantification of each greenhouse gas statement during the crediting period. This discount is applied in the projection-based baseline and considered 'retired to the atmosphere'.
Higher Heating Value (HHV)	The amount of heat released during the combustion of a fuel and includes the latent heat in the water produced through combustion. Use of HHV assumes that heat below150°C can be utilized.
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_2e threshold or

	have opted-in to the Regulation. Emissions are accounted for and verified on an annual basis.
New CO_2	Anthropogenic CO_2 recently captured and not previously injected into a reservoir and recycled, or recently captured CO_2 from a direct air capture facility. Must not have previously been credited for sequestration.
Opt-In Facility	A facility that met the requirements and applied to be regulated under the regulation.
Permanent Storage/Net Geological Sequestration	The isolation of CO_2 in subsurface formations. Injected CO_2 is trapped through mechanisms outlined in section 3.0.
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.
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]
SSR	Source, sink and reservoirs, as defined above.
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
Targeted Geologic Storage Zone(s)	The targeted geological formation(s) that contribute to providing secure long-term sequestration of CO_2 as outlined in the D065 Scheme Approval. It may include one or more seals and one or more zones that have the potential to accept sequestered CO2.
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 targeted zone(s) (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]

2.0 Baseline Condition

The baseline scenario for this protocol is projection-based. It assumes the continued practice of emitting CO_2 to the atmosphere from an emission source.Baseline emissions are projected using the quantity of CO_2 measured directly upstream of the injection wellheads less any injected CO_2 that originated within the offset project boundary. These emissions are assessed dynamically and comprise a portion of the total emissions from the emissions source. This dynamic baseline ensures that variation in CO_2 that is captured and injected in the project condition is accounted for.

2.1 Identification of Baseline Sources and Sinks

The identification of sources, sinks and reservoirs (SSRs) 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. 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 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 SSRs 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 Fi . 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 .

***Figure 1**:Process Flow Diagram for the Baseline Condition*

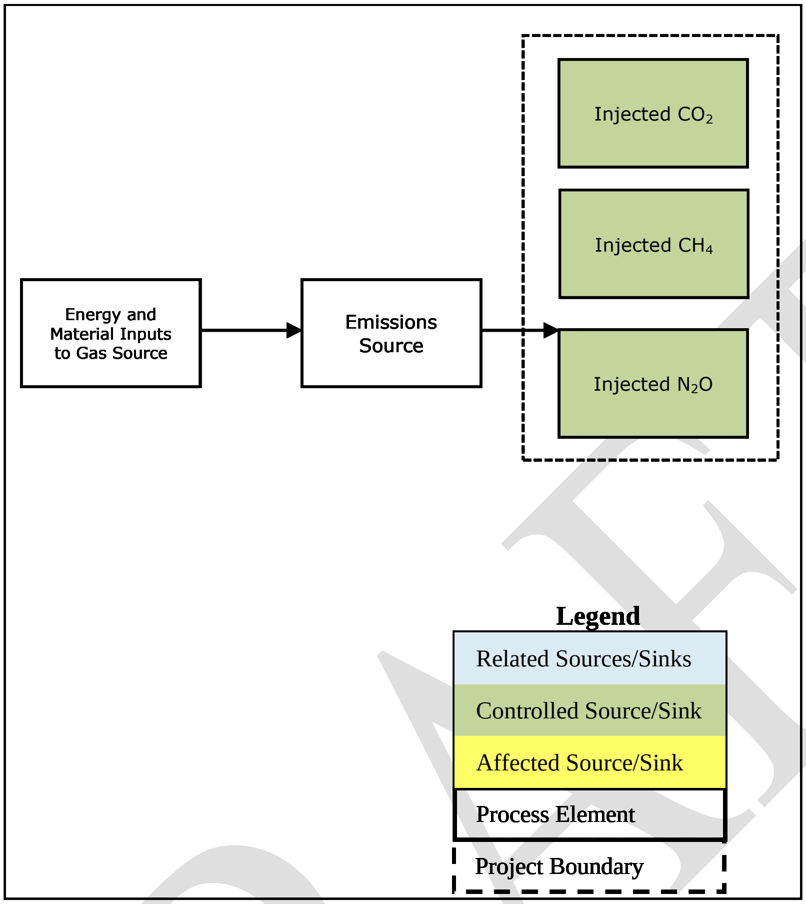


***Table 1:** Baseline Process Elements*

Process Element	Description
Energy and Material Inputs to Gas Source	Energy and material inputs to the gas source require inputs such as electricity, heat and fuel, which may be supplied from on-site or off-site sources. Process elements are included for illustrative purposes only, and they do not affect the quantification.
Emissions Source	The emissions source includes any type of process that generates CO_2-rich gas from a GHG regulated facility in Alberta. Process elements are included for illustrative purposes only, and they do not affect the quantification.

Figure 2: *Baseline Sources and Sinks*

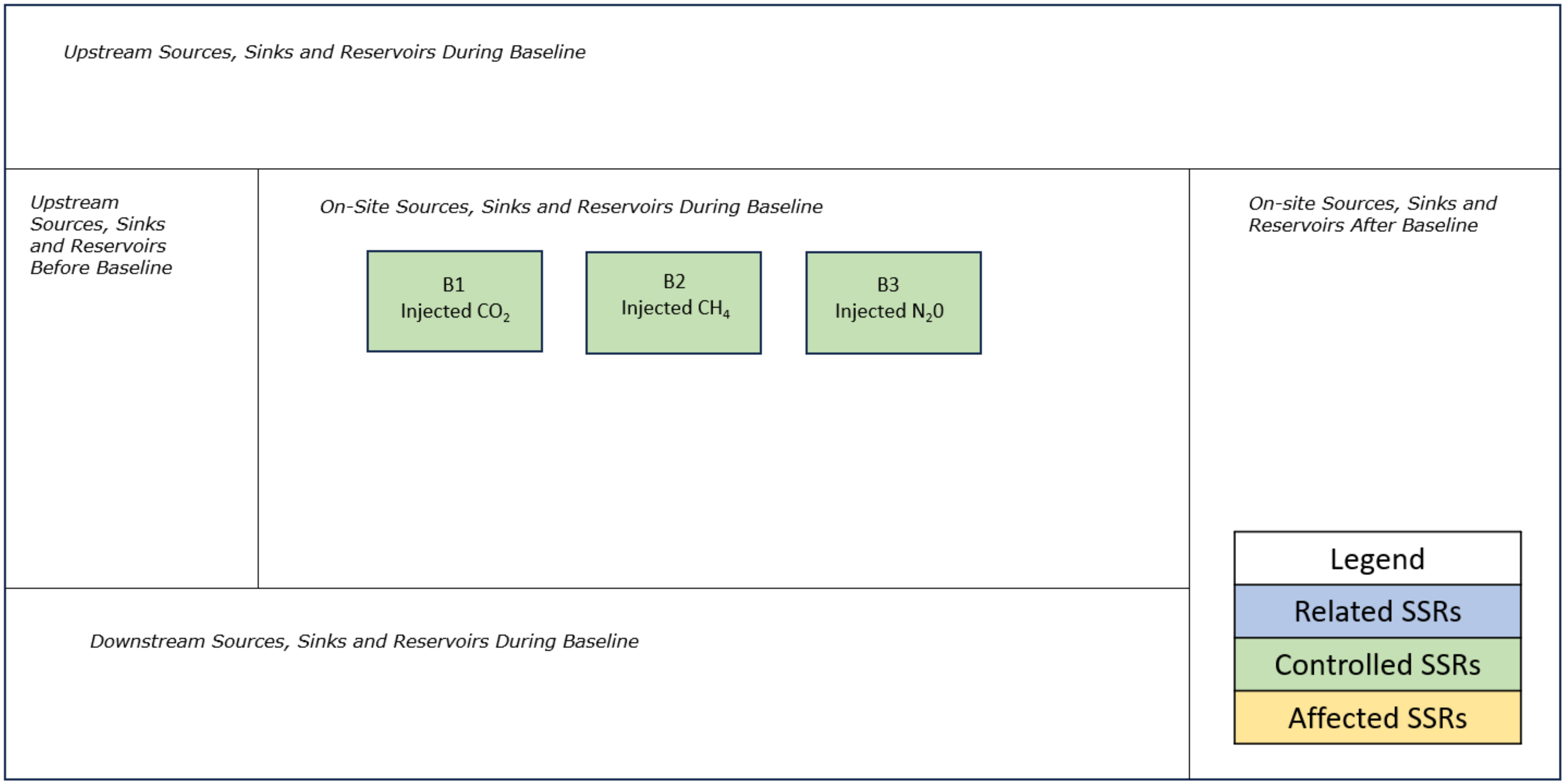


Table 2: *Baseline Sources and Sinks*

Source/Sinks	Description	Type
Upstream Source/Sinks During Baseline Operation – Not Applicable		
On-Site Sources and Sinks During Baseline		
B1 Injected CO_2	All CO_2 emissions released to the atmosphere in baseline, as projected from the project condition. Baseline emissions are projected using the direct measurement of the quantity of gas that has been measured upstream of the injection wellheads in the project condition. These emissions are a portion of the total emissions from the emissions source.	Controlled
B2 Injected CH_4	All CH_4 emissions released to the atmosphere in baseline, as projected from the project condition. Baseline emissions are projected using the direct measurement of the quantity of gas that has been measured upstream of the injection wellheads in the project condition. These emissions are a portion of the total emissions from the emissions source.	Controlled
B3 Injected N_2O	All N_2O emissions released to the atmosphere in baseline, as projected from the project condition. Baseline emissions are projected using the direct measurement of the quantity of gas that has been measured upstream of the injection wellheads in the project condition. These emissions are a portion of the total emissions from the emissions source.	Controlled
Downstream Sources and Sinks During Baseline – Not Applicable		
Downstream Sources and Sinks After Baseline – Not Applicable		

3.0 Project Condition

Carbon capture and storage projects generally consist of three distinct components: the capture and compression of CO_2; the transport of CO_2 to the injection wells; and the metering and disposal of CO_2 through injection wells and into a targeted geologic storage zone(s) suitable for permanent sequestration.

The main process elements of a typical carbon capture and storage project are described below. Carbon capture and storage projects may employ other CO_2 capture, transport, disposal technologies, and processes. Flexibility to accommodate these different approaches is discussed in Section 1.4.

Approval from the Director will be required for all new emission offset projects and includes 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 CO_2 and update the offset project plan to document the change in project scenario.

CO_2 Capture and Compression

For this protocol, only New CO_2 reported as exported from a regulated large emitter or opted-in facility that is ultimately captured is eligible. CO_2 capture refers to the process of capturing CO_2, and often includes the separation of CO_2 from other gas species generated at the emissions source. All CO_2 capture technologies are eligible under this protocol. The typical CO_2 capture infrastructure consists of the following main process blocks.

- CO_2 capture from existing high purity process streams, e.g., fertilizer plant, gasification; or,
- CO_2 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;
  - CO_2 vent stack; and
- CO_2 compression, which may include a multi-stage compressor with an electrical motor and interstage coolers and knockout drums, CO_2 dehydration and interim CO_2 holding facilities.

GHG emissions associated with capture and compression processes are accounted for either at the large emitter/op-in facility or in the project condition as part of the CO_2 capture and/or compression system, as applicable.

Carbon dioxide captured by Direct Air Capture facilities may be eligible capture sources through flexibility mechanisms outlined in section 1.4.

Transport

The transportation system may be a pipeline including booster compression and/or pumps to transport CO_2 from the capture facility to the injection well(s). Alternatively, transportation could be CO_2 moved by vehicle from the capture facility to the injection wells or to a transload receiving facility on a CO_2 pipeline.

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 may be used to collect and transmit data from the pipeline to a control centre and to monitor line block valves. CO_2 is typically transferred in a dense phase. Emissions arising from the inline compression and pumping of CO_2 are accounted for as part of the transport system.

Geologic Sequestration Target Storage Zone(s)

The CO_2 storage infrastructure may include injection wells, measurement and gas analysis equipment, pumping equipment and flow lines from the main transportation system to the individual injection wells.

Metering of injected fluid quantities and CO_2 concentration to calculate injected CO_2 quantity takes place as close as reasonably practicable to the injection point, and must be described by project schematics. A mass balance approach may be appropriate if measured parameters are provided for all inputs except for the one variable being solved for.

Once injected into the targeted sequestration scheme geologic storage zone(s) as defined by the Directive 065 scheme approval, CO_2 is contained within the pore spaces of the reservoir. A targeted geologic storage zone(s) may include depleted reservoirs. Geologic storage, with the exception of adsorption, is most efficient at depths where the formation pressure and temperature are sufficient to cause CO_2 to remain in a dense state.

CO_2 is stored by one or more of the following trapping mechanisms[1]:

- 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 (CO_2 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., CO_2 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 are subject to the terms of the Directive 065 approval for compliance.

3.1 Identification of Project Sources and Sinks

Sources and/or sinks for the project condition are based on existing best practice guidance contained in other similar and relevant greenhouse gas quantification protocols, ISO 14064-2 (2019), and carbon capture and storage project configurations. This process confirmed that sources and/or sinks in the process flow diagram covered the full scope of eligible project activities under this protocol. Process elements are described in .

These sources and/or sinks are further refined according to the lifecycle categories identified in . These sources and/or sinks are further classified as controlled, related or affected as described in .

[1] Part II: Carbon Capture and Geological Storage, International Petroleum Industry Environmental Conservation Association and American Petroleum Institute, June 2007.

Figure 3: Process Flow Diagram for the Project Condition

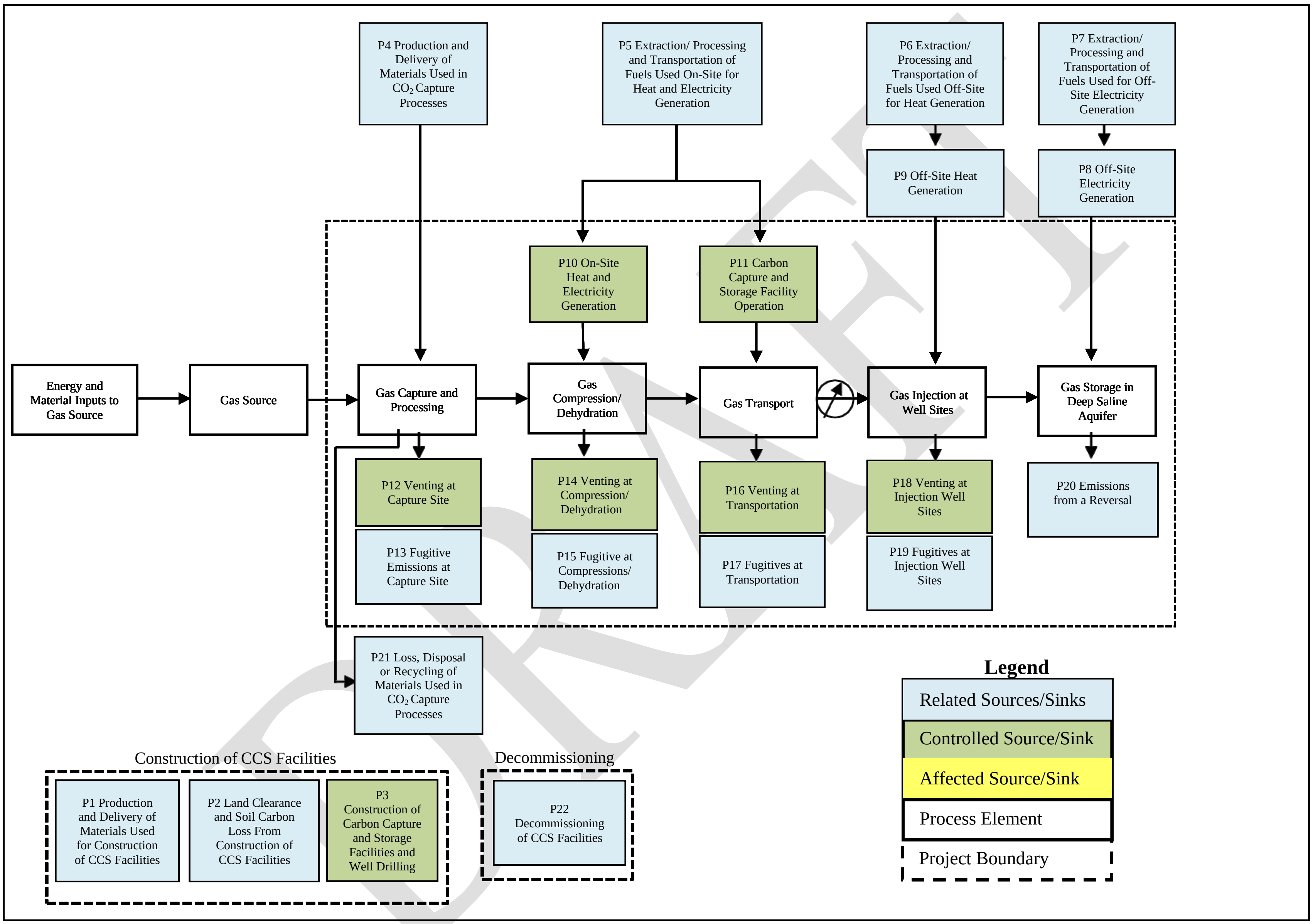


Table 3: *Project Process Elements*

Process Element	**Description**
Energy and Material Inputs to Gas Source	Energy and material inputs to the gas source require inputs such as electricity, heat and fuel, which may be supplied from on-site or off-site sources. Process elements are included for illustrative purposes only, and they do not affect the quantification.
Gas Source	The gas source includes any type of process that generates CO_2-rich gas. Process elements are included for illustrative purposes only, and they do not affect the quantification.
Gas Capture and Processing	The CO_2-rich gas 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 chemical solvent such as amine regeneration. Process elements are included for illustrative purposes only, and they do not affect the quantification.
Gas Compression and Dehydration	The CO_2-rich gas stream must be compressed before it can be transported to the disposal site. Dehydration may also be required to prevent hydrate formation. This may be achieved through heating or other processes. Process elements are included for illustrative purposes only, and they do not affect the quantification.
Gas Transport	The CO_2-rich gas stream will be transported via pipeline to the injection site. Depending on the length of the pipeline, additional compression may be needed. Process elements are included for illustrative purposes only, and they do not affect the quantification.
Gas Injection at Wells	The CO_2-rich gas stream will be injected into the underground formation. In certain cases, additional energy inputs may be required at the injection wells for the injection operation or to operate monitoring equipment. Process elements are included for illustrative purposes only, and they do not affect the quantification.
CO_2 Storage in Targeted Geologic Zone(s)	The CO_2-rich gas stream will be disposed in a geologic zone(s) suitable for permanent storage of injected CO_2. Process elements are included for illustrative purposes only, and they do not affect the quantification.

Figure 4: *Project Condition Sources and Sinks*

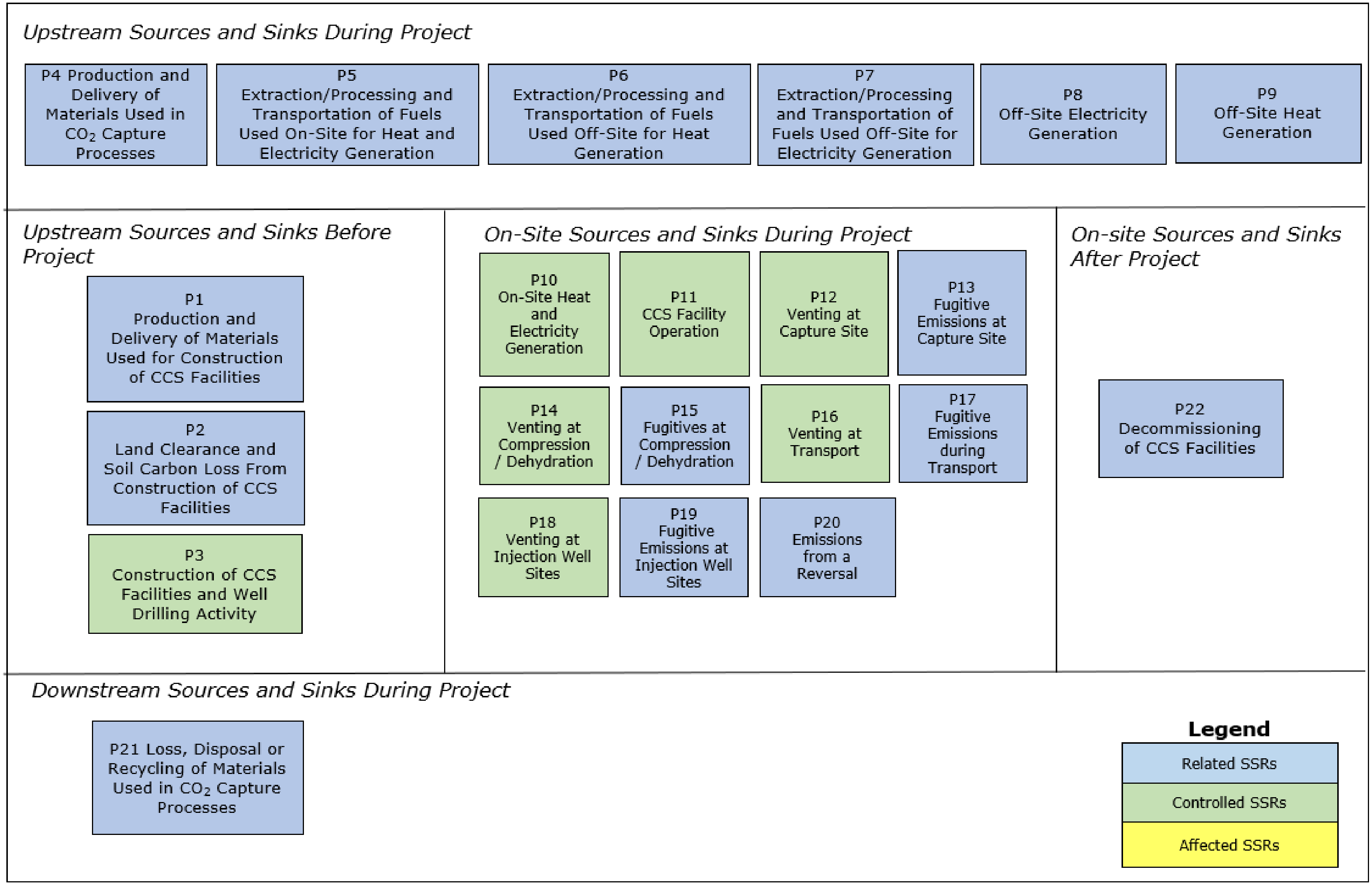


Table 4: *Project Condition Sources and Sinks*

Source/Sink	Description	Type
Upstream Sources and Sinks Before Project		
P1 - Production and Delivery of Materials Used for Construction of Carbon Capture and Storage Facilities	Materials used in the construction of carbon capture and storage 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.	Related
On-site Sources and Sinks Before Project		
P2 - Land Clearing and Soil Carbon Loss from Construction of Carbon Capture and Storage Facilities	The clearing of vegetative or forest land for site preparation may cause soil to release carbon dioxide into the atmosphere that was previously stored in soil.	Related
P3 - Construction of Carbon Capture and Storage Facilities and Well Drilling Activity	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.	Controlled
Upstream Sources and Sinks During Project		
P4 - Production and Delivery of Material Inputs used in CO_2 Capture Process	Material inputs for CO_2 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.	Related
P5 - Extraction/Processing and Transportation of Fuels Used On-Site for Heat and Electricity Generation	The fuels used for heat and electricity generation will need to be extracted, processed, and delivered to the site. Delivery may include shipments by truck, rail or pipeline. CO_2, CH_4 and N_2O emissions are associated with these activities. Volumes and types of fuels used must be tracked.	Related
P6 - Extraction/Processing and Transportation of Fuels Used Off Site for Heat Generation	The fuels used for heat generation will need to be extracted, processed, and delivered to the off-site facility. Delivery may include shipments by truck, rail or pipeline. CO_2, CH_4 and N_2O emissions are associated with these activities. Volumes and types of fuels used must be tracked.	Related
P7 - Extraction/Processing and Transportation of Fuels Used Off Site for Electricity Generation	The fuels used for the generation of off-site electricity must be extracted, processed, and delivered to the generating stations. Delivery may include shipments by truck, rail or pipeline. CO_2, CH_4 and N_2O emissions are associated with these activities. The quantity of off-site electricity used to operate the carbon capture and storage facilities as well as the quantity and type of fuel used for the generation of incremental directly connected electricity must be tracked.	Related

P8 - Off-Site Electricity Generation	The total quantity of electricity used by the carbon capture and storage facility 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 can include: • Grid Electricity: • All sources of electricity delivered by the provincial grid must apply the most current grid intensity factor published by AEPA.	Related
P9 - Off-Site Heat Generation	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: • Industrial heat from a regulated large emitter; or • Heat from a non-regulated entity; or • Offset project	Related
On-Site Sources and Sinks During Project		
P10 - On-Site Heat and Electricity Generation	Heat, steam and electricity inputs may be required for CO_2 capture, processing, compression, dehydration, transportation and injection. Heat and electricity may be generated independently or from cogeneration within the project boundary. The quantity and type of fuels consumed to generate electricity and heat, and the quantity of heat and electricity consumed by the project from each generating source must be tracked. Where waste heat from another facility is being used, the quantity of heat from all sources needs to be measured relative to the energy content of each source.	Controlled
P11 - Carbon Capture and Storage Facility Operation	The CO_2 pipeline and injection well must undergo regular inspection and monitored for leaks. The geological formation must also be monitored and tested regularly for signs of CO_2 leakage and/or migration consistent with the approved Monitoring, Measurement, and Verification Plan requirements associated with the scheme approval under D065. Greenhouse gas emissions are released from fossil fuels consumed for maintenance activities for leak prevention and repair. These stationary and mobile sources may have natural gas, propane, and diesel energy inputs. Quantities and types for each of the energy inputs must be tracked.	Controlled
P12 - Venting of CO_2 at Capture Site	Some CO_2 is vented from the hydrogen production units during the project condition. CO_2 venting may also be necessary for equipment maintenance or emergency shutdowns.	Controlled
P13 - Fugitive Emissions at Capture Site	Unintended leaks of gas from the CO_2 capture and processing unit may occur through faulty seals, loose fittings, or equipment. These gases will be primarily composed of H_2 and CO_2.	Related

P14 – Venting of CO_2 during Compression / Dehydration	Planned and emergency CO_2 venting may be necessary for compressor and dehydrator maintenance and/or emergency shutdowns.	Controlled
P15 – Fugitive Emissions During Compression / Dehydration	Unintended leaks of gas from the compressor and/or dehydrator may occur through seals, loose fittings, equipment, or compressor packing. These gases will be composed primarily of CO_2 with trace amounts of other gases.	Related
P16 - Venting of CO_2 During Transportation	Planned and emergency CO_2 venting may be necessary for pipeline maintenance and/or shutdowns.	Controlled
P17 - Fugitive Emissions During Transportation	Unintended leaks of gas from the CO_2 pipeline, transportation equipment, and additional compressors may occur through seals, loose fittings, equipment, or compressor packing. These gases will be composed primarily of CO_2 with trace amounts of other gases.	Related
P18 - Venting of CO_2 at Injection Well Sites	Planned and emergency CO_2 venting may be necessary for 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 volume of CO_2 vented.	Controlled
P19 - Fugitive Emissions at Injection Well Sites	Unintended leaks of gas at the CO_2 injection well sites may occur through valves, flanges, pipe connections, mechanical seals, or related equipment. These gases will be composed primarily of CO_2 with trace amounts of other gases. These emissions must be quantified.	Related
P20 - Emissions from a Reversal	Accidental emissions 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. These emissions must be quantified.	Related
Downstream Sources and Sinks During Project		
P21 - Loss, Disposal, or Recycling of Materials Used in CO_2 Capture Processes	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. These emissions must be quantified.	Related
Downstream Sources and Sinks After Project		
P22 - Decommissioning Carbon Capture and Storage of 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

4.0 Quantification

Baseline and project conditions were assessed against each other to determine the scope of emissions 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 as included or excluded and the justification for each of these choices is provided.

__Table 5:__ Comparison of Sources and Sinks

Identified Source/Sink	Baseline	Project	Include or Exclude from Quantification	Justification for Inclusion/Exclusion
Upstream Sources and Sinks Before Project				
P1 - Production and Delivery of Materials Used for Construction of Carbon Capture and Storage Facilities	N/A	Related	Exclude	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 carbon offset system.
Upstream Sources and Sinks Before Project				
P2 - Land Clearance and Soil Carbon Loss from Construction of Carbon Capture and Storage Facilities	N/A	Related	Exclude	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 carbon offset system.
P3 - Construction of Carbon Capture and Storage Facilities and Well Drilling Activity	N/A	Controlled	Exclude / **Include reportable drilling releases**	This one-time only source of greenhouse gas emissions is negligible compared to the expected size and long lifetime of the project. Its exclusion may be consistent with other approved protocols in the Alberta carbon offset system. Any drilling releases that trigger the Alberta Energy Regulator's Directive 059 reporting threshold for kicks or blowouts must be included in the project emissions.
Upstream Sources and Sinks During Project				
P4 - Production and Delivery of Material Inputs used in CO_2 Capture Process	N/A	Related	**Include**	This source/sink may have a material impact on project emissions resulting from increased upstream chemical production associated with project period chemical usage.

Identified Source/Sink	Baseline	Project	Include or Exclude from Quantification	Justification for Inclusion/Exclusion
P5 - Extraction/Processing and Transportation of Fuels Used On Site for Heat and Electricity Generation	N/A	Related	**Include**	This source/sink is likely to have a material impact on projects.
P6 - Extraction/Processing and Transportation of Fuels Used Off Site for Heat Generation	N/A	Related	**Include**	This source/sink is likely to have a material impact on projects.
P7 - Extraction/Processing and Transportation of Fuels Used for Generation of Off-Site Electricity	N/A	Related	**Include**	Emissions associated with the fuel used for grid electricity has been excluded to maintain consistency with other government-approved protocols in the Alberta carbon offset system. However, if incremental, directly connected electricity is being used, emissions associated with the fuel used for electricity generation must be included.
P8 - Off-Site Electricity Generation	N/A	Related	**Include**	This source/sink is likely to have a material impact on projects.
P9 - Off-Site Heat Generation	N/A	Related	**Include**	This source/sink is likely to have a material impact on projects.
On-Site Sources and Sinks During Project				
B1 - Injected CO_2	Controlled	N/A	**Include**	This source/sink is the data point against which all project emissions are subtracted. It is used to establish the baseline emissions for the project.
B2 - Injected CH_4	Controlled	N/A	Exclude	It is conservative to exclude CH_4 from the injected quantity as this would be an impurity in the process stream. Exclusion of this source also avoids a perverse incentive for the inefficient separation of the CO_2 stream.

Identified Source/Sink	Baseline	Project	Include or Exclude from Quantification	Justification for Inclusion/Exclusion
B3 - Injected N_2O	Controlled	N/A	Exclude	It is conservative to exclude N_2O from the injected quantity as this would be an impurity in the process stream. Exclusion of this source also avoids a perverse incentive for the inefficient separation of the CO_2 stream.
P10 - On-Site Heat and Electricity Generation	N/A	Controlled	**Include**	This source/sink is likely to have a material impact on projects.
P11 - Carbon Capture and Storage Facility Operation	N/A	Controlled	**Include**	This source/sink is likely to have a material impact on projects.
P12 - Venting of CO_2 at Capture Site	N/A	Controlled	Exclude	The vented and fugitive emissions that occur upstream of the injected wellhead meter in the project condition would have been emissions in the baseline condition in the absence of the carbon capture and storage project. These emissions are therefore excluded from the quantification.
P13 - Fugitive Emissions at Capture Site	N/A	Related	Exclude	The vented and fugitive emissions that occur upstream of the injected wellhead meter in the project condition would have been emissions in the baseline condition in the absence of the carbon capture and storage project. These emissions are therefore excluded from the quantification.
P14 - Venting of CO_2 During Compression/Dehydration	N/A	Controlled	Exclude	The vented and fugitive emissions at occur upstream of the injected wellhead meter in the project condition would have been emissions in the baseline condition in the absence of the carbon capture and storage project. These emissions are therefore excluded from the quantification.

Identified Source/Sink	Baseline	Project	Include or Exclude from Quantification	Justification for Inclusion/Exclusion
P15 - Fugitive Emissions During Compression/ Dehydration	N/A	Related	Exclude	The vented and fugitive emissions that occur upstream of the injected wellhead meter in the project condition would have been emissions in the baseline condition in the absence of the carbon capture and storage project. These emissions are therefore excluded from the quantification.
P16 - Venting of CO_2 During Transportation	N/A	Controlled	Exclude	The vented and fugitive emissions that occur upstream of the injected wellhead meter in the project condition would have been emissions in the baseline condition in the absence of the carbon capture and storage project. These emissions are therefore excluded from the quantification.
P17 - Fugitive Emissions During Transportation	N/A	Related	Exclude	The vented and fugitive emissions that occur upstream of the injected wellhead meter in the project condition would have been emissions in the baseline condition in the absence of the carbon capture and storage project. These emissions are therefore excluded from the quantification.
P18 - Venting of CO_2 at Injection Well Sites	N/A	Controlled	**Included**	This source/sink must be included because it occurs downstream of the injection meter. Resulting emissions may have material impact on the project.

Identified Source/Sink	Baseline	Project	Include or Exclude from Quantification	Justification for Inclusion/Exclusion
P19 - Fugitive Emissions at Injection Well Sites	N/A	Related	**Include**	This source/sink only includes fugitive emissions emitted at the injection site from surface facilities. These emissions may occur downstream of metering equipment. Fugitive emissions upstream of metering would also have been emissions in the baseline condition and are excluded from project emissions quantification. Fugitive emissions downstream of the metering equipment and upstream of the subsurface must be included. Fugitive emissions downstream of the metering equipment and down hole are quantified in P20 Emissions from a Reversal.
P20 - Emissions from a Reversal	N/A	Related	**Include**	Under normal operation, this source/sink is negligible and is excluded from quantification. However, emissions from leakage events must be quantified and included consistent with the approved measurement, monitoring and verification plan under the D065 scheme approval.
Downstream Sources and Sinks During Project				
P21 - Loss, Disposal, or Recycling of Materials Used in CO_2 Capture Processes	N/A	Related	**Include**	This source/sink is likely to have a material impact on projects resulting from increased greenhouse gas emissions associated with downstream chemical loss, disposal or recycling of project period chemical usage.
Downstream Sources and Sink After Projects				
P22 - Decommissioning of Carbon Capture and Storage Facilities	N/A	Related	Exclude	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 carbon offset system.

4.1 Project 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_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, 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 the Regulation are exempt from the federal fuel charge and CO_2 exported from the 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.

GHG Statement (the following items must be listed separately in the project report and be itemized by reporting period and by vintage year)
Discount Emission Reductions = Injected CO_2 * D
Net Geological Sequestration = Emissions $_{Baseline}$ – Emissions $_{Project}$ – Discounted Emission Reductions

D = Discount applied to injected CO_2 for unintentional reversals. Set equal to 0.005.

$$\text{Emission Reduction} = \text{Emissions}_{\text{Baseline}} - \text{Emissions}_{\text{Project}}$$

$$\text{Emissions}_{\text{Baseline}} = \text{Emissions}_{\text{Injected CO2}} - CO_{2\,\text{injected originating within project boundary}}$$

$$\begin{aligned}
&\text{Emissions}_{\text{Project}} = \\
&\text{Emissions}_{\text{Production and Delivery of Material Inputs}} + \\
&\text{Emissions}_{\text{Construction and Well Drilling}} + \\
&\text{Emissions}_{\text{Fuel Extraction and Processing}} + \\
&\text{Emissions}_{\text{Off-Site Electricity Generation}} + \\
&\text{Emissions}_{\text{Off-Site Heat Generation}} + \\
&\text{Emissions}_{\text{On-Site Heat and Electricity Generation}} + \\
&\text{Emissions}_{\text{Carbon Capture and Storage Facility Operation}} + \\
&\text{Emissions}_{\text{Venting of CO2 at Injection Well Sites}} +
\end{aligned}$$

Emissions $_{\text{Fugitives from Injection Well Sites}}$ +
Emissions $_{\text{Subsurface to Atmosphere}}$ +
Emissions $_{\text{Loss, Disposal or Recycling of Material Inputs}}$ –
CO_2 $_{\text{injected originating within project boundary}}$

Total CO_2 Equivalent Emissions = $\sum$ (CO_2 emissions)* GWP $_{CO2}$ + $\sum$ (CH_4 emissions)* GWP $_{CH4}$ + $\sum$ (N_2O emissions)* GWP $_{N2O}$

Where:

Emissions $_{\text{Baseline}}$ = emissions projected from the measured quantity of CO_2 injected in the project condition, but does not include CH_4 and N_2O less CO_2 injected originating within the project boundary.

Emissions $_{\text{Injected CO2}}$ = emissions under B1 Injected CO_2

Emissions $_{\text{Project}}$ = sum of the emissions under the project condition

Emissions $_{\text{Construction and Well Drilling}}$ = emissions under P3 Construction of CCS Facility and Well Drilling Activity

Emissions $_{\text{Production and Delivery of Material Inputs}}$ = emissions under P4 Production and Delivery of Materials Used in the CO_2 Capture Process

Emissions $_{\text{Fuel Extraction and Processing}}$ = emissions under P5, P6 and P7 Extraction/ Processing and Transportation of Fuels Used On/ Off Site for Heat and Electricity Generation

Emissions $_{\text{Off-Site Electricity Generation}}$ = emissions under P8 Off-Site Electricity Generation

Emissions $_{\text{Off-Site Heat Generation}}$ = emissions under P9 Off-Site Heat Generation

Emissions $_{\text{On-Site Heat and Electricity Generation}}$ = emissions under P10 On-Site Heat and Electricity Generation - CO_2 $_{\text{injected originating within project boundary}}$

Emissions $_{\text{Carbon Capture and Storage Facility Operation}}$ = emissions under P11 Carbon Capture and Storage Facility Operation

Emissions $_{\text{Venting CO2 at Injection Well Sites}}$ = emissions under P18 Venting at Injection Well Sites

Emissions $_{\text{Fugitives from Injection Well Sites}}$ = emissions under P19 Fugitives at Injection Well Sites

Emissions $_{\text{Subsurface to Atmosphere}}$ = emissions under P20 Emissions from a Reversal

Emissions$_{\text{Loss, Disposal or Recycling of Material Inputs}}$ = emissions under P21 Emissions from Loss, Disposal or Recycling of Materials Used in CO_2 Capture Process

CO_2 $_{\text{Equivalent}}$ Emissions = sum of all greenhouse gas emissions converted to CO_2 equivalent terms, and does not apply to injected volumes of CH_4 or N_2O

4.2.1 Flexibility Mechanism 3 – Limiting Liability to Three Years of Annual Average Injection

Outlined below is the approach for quantifying the net geological sequestration for Projects who elect to limit reversal liability to three years of average annual injection (calculated as an annual average over the life of the crediting period, multiplied by three years) through Flexibility Mechanism 3.

Project Assertion (the following items must be listed separately in Project Report and be itemized by reporting period and by vintage year)
Discount Emission Reductions = Injected CO2 * D
Net Geological Sequestration = Emissions $_{\text{Baseline}}$ – Emissions $_{\text{Project}}$ – Discounted Emission Reductions

D = Discount applied to injected CO_2 for unintentional reversals. Set equal to 0.005 for emission offset project reporting period year 1, 2, 3 inclusive then 0.01 for year 4 onward for each reporting period, including extension.

Emissions baseline and Emissions project quantification remain the same as shown in section 4.2.

4.3 Offset Eligible Emission Reductions (non-priced emissions)

Reductions or sequestration of emissions that are not subject to a carbon price are eligible to be quantified for emission offsets; reductions of emissions that are subject to a carbon price are not eligible to be quantified for emission offsets. Projects that quantify offset eligible emission reductions must also quantify and report on priced emission reductions as per section 4.3.1.

$$\textbf{Offset Eligible Emission Reductions} = \textbf{Emissions}_{\textbf{Non-priced Baseline}} - \textbf{Emissions}_{\textbf{Non-priced Project}}$$

4.3.1 Priced Emission Reductions

Emission reductions that are subject to a carbon price are not eligible for emission offsets. Projects 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. It is the responsibility of any third-party assurance provider to confirm quantification and methodology applied to a projects GHG Statement.

4.3.2 Negligible Emissions

Project developers can apply via a deviation request to the Director for alternative measurement and quantification requirements associated with emissions that fall under the negligibility threshold defined as “negligible emission sources” under the Alberta Greenhouse Gas Quantification Methodologies.

Table 6: *Quantification Methodology*

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
Baseline Sources and Sinks						
B1 - Injected CO_2	*Where: Volumetric flow measurement is used:* $Emissions_{\ Injected\ CO2} = \ \Sigma\ (Vol._{\ Injected\ Gas}\ *\ \%_{\ CO2}\ *\ \rho_{CO2})$ *Where: Mass flow measurement is used:* $Emissions_{\ Injected\ CO2} = \ \Sigma\ (Mass\ Fraction_{CO2,\ normalized}\ *\ Mass_{Gas})$					
	$Emissions_{\ Injected\ CO2}$	t of CO_2e	N/A	This value refers to the injected quantity of New CO_2 measured at the metering point in the project condition. The measured volume, composition, temperature and pressure are used to calculate the mass of CO_2 (excludes CH_4 and N_2O).	N/A	Mass of CO_2 to be calculated from direct measurement, and corrected for temperature and pressure. Frequency of metering is highest level possible.
	Volume of injected gas / $Vol._{\ Injected\ Gas}$	L / m^3 / other	Measured	Direct metering of volume of gas measured at the metering point in the project condition, measured directly at each injection well.	Continuous metering	Direct metering is standard practice. Frequency of metering is highest level possible.
	Density of injected CO_2 / $\rho_{\ Injected\ CO2}$	Kg / m^3	Estimated	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 pressure or temperature used for the specific meter calibration .	Daily	Densities must be used consistently throughout project.

	Concentration of injected CO_2 / $\%_{\text{Injected CO2}}$	%Volume	Measured	The CO_2 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 CO_2 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 down-stream of the tie in such that the concentration of the comingled stream is taken. Alternatively, the measurement can be taken down-stream 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.	Daily	A minimum of daily samples averaged monthly on volumetric basis.
	Mass_{Gas}	Tonnes	Measured	Direct metering of mass of gas measured at the metering point in the project condition, measured directly at each injection well.	Continuous metering	Direct metering is standard practice. Frequency of metering is highest level possible.
	Mass Fraction $_{\text{CO2, normalized*}}$	%	Measured	The CO_2 mass fraction must be directly measured downstream of the capture and processing equipment or upstream of the injection field at a custody transfer point. When additional CO_2 streams comingle with a capture stream of known concentration, the concentration of comingled stream	Daily	The mass fraction of CO_2 is dependent upon the mass fraction of all components in the stream. If components totaling 99.5% of mass fraction are measured, the unmeasured components should

				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 down-stream of the tie in such that the concentration of the comingled stream is taken. Alternatively, the measurement can be taken down-stream 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. * Note: normalization of the mass fraction of CO_2 requires measurement of other components that sum to at least 99.5% of the known components in the stream.		have an immaterial effect on injected CO_2.

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
Project Sources and Sinks						
P3 - Construction of Carbon Capture and Storage Facilities and Well Drilling Activity	$Emissions_{Drilling\ Injection\ Well\ Sites} = \sum (Vol._{Gas\ Kick} * \%_{i\ CO2,\ CH4,\ N2O} * \rho_{i\ CO2,\ CH4,\ N2O}) * GWP_{CO2,\ CH4,\ N2O}$					
	$Emissions_{Venting\ at\ Injection\ Well\ Sites}$	t of CO_2e	N/A	N/A	N/A	Quantity being calculated.
	Volume of Vent Gas / $Vol._{Gas\ Kick}$	L / m^3 / other	Estimated	If the drilling activity resulted in a kick or a blowout, Directive 059 submission is triggered. The values submitted in the Directive 059 report should be used to estimate the volume of gas released.	Engineering estimate per event	The measurement approach should follow Directive 059 instructions and should be as frequent as the event.
	Density of vented gas / $\rho_{i\ CO2,\ CH4,\ N2O}$	kg/m^3	Estimated	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 pressure or temperature used for the specific meter calibration.	N/A	Densities must be used consistently throughout project.
	$GWP_{CO2,CH4,N20}$	Unitless	Estimated	As per the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Section 1(3) of TIER requires that offset projects use the GWPs published in the most recent version of the Standard.

P4 - Production and Delivery of Material Inputs used in CO_2 Capture Process	$$Emissions_{Production\ \&\ Delivery\ of\ Material\ Inputs} = \sum (Input_i * EF\ Input_{i\ CO2,\ CH4,\ N2O}) * GWP_{CO2,\ CH4,\ N2O}$$					
	$Emissions_{Production\ \&\ Delivery\ of\ Material\ Inputs}$	t of CO_2e	N/A	N/A	N/A	Quantity being calculated in aggregate based on quantity of inputs used throughout the carbon capture and storage operations.
	Quantity of material inputs consumed for carbon capture and storage facility operation / $Input_i$	t/L/m^3/ Other	Estimated	Estimation of the quantity of material inputs consumed for the carbon capture and storage project.	Annual	Engineering report will specify the quantity of material input required for an appropriately sized carbon capture and storage facility. Represents most reasonable means of estimation.
	Emissions factor for each type of material input / $EF\ Input_{i\ CO2,\ CH4,\ N2O}$	t CO_2e per t/L/ m^3/other	Estimated	Project specific design.	Annual	Production and delivery estimates for the emission factors for the material inputs.
	$GWP_{CO2,CH4,N20}$	Unitless	Estimated	As per the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Section 1(3) of TIER requires that offset projects use the GWPs published in the most recent version of the Standard.

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
P5, P6 & P7 - Extraction Processing and Transport of Fuels Used On Site for Heat and Electricity Generation	$Emissions_{Fuel\ Extraction\ and\ Processing} = \sum (Fuel_i * EF\ Fuel_{i\ CO2,\ CH4,\ N2O}) * GWP_{CO2,\ CH4,\ N2O}$					
	$Emissions_{Fuel\ Extraction\ and\ Processing}$	t of CO_2e	N/A	N/A	N/A	Quantity being calculated in aggregate based on quantity of fossil fuels used at each component of the carbon capture and storage operations.
	Total Quantity of fossil fuels consumed to operate carbon capture and storage facilities / Fuel i	M^3/MJ/ Other	Measured	Direct measurement of the quantity of fossil fuels consumed at each component of the carbon capture and storage project.	Continuous metering	Quantity being calculated in aggregate based on quantity of inputs used throughout the carbon capture and storage operations.
	Emissions factor for extraction and processing of each type of fuel / $EF\ Fuel_{i\ CO2,\ CH4,\ N2O}$	t CO_2e per m^3/ MJ/other	Estimated	From CAPP or other reference documents. Refer to Carbon Offset Emission Factors Handbook	Annual	Reference values represent best available emission factors for fuel extraction and processing.
	$GWP_{CO2,CH4,N20}$	Unitless	Estimated	As per the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Section 1(3) of TIER requires that offset projects use the GWPs published in the most recent version of the Standard.

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
P8 - Off-Site Electricity Generation	$Emissions_{\text{Off-Site Electricity Generation}} = Electricity_{import} * EF_{Electricity}$ $EF_{electricity}$ = *Carbon Offset Emission Factors Handbook (use increased on-site grid electricity use (includes line loss))*					
	Emissions $_{\text{Off-Site Electricity Generation}}$	t CO_2e	N/A	N/A	N/A	Total off-site electricity emissions quantity being calculated based on the quantity of electricity sourced from outside the project
	Total quantity of delivered electricity consumed for the emission offset project / Electricity $_{Grid}$	MWh	Measured	Direct measurement of delivered electricity consumed by each electrical load involved in the capture, compression, transport, injection and storage of CO_2. The total electricity consumption should be calculated as the sum of electricity consumption across individual components of the CO_2 sequestration emission offset project. These projects require an individual meter for delivered electricity	Continuous metering	Continuous direct metering represents the industry practice and the highest level of detail
	Emission intensity factor for electricity generation / EF $_{electricity}$	t CO_2e / MWh	Estimated	Grid emission intensity factor for each year obtained from the Carbon Offset Emission Factors Handbook. No reduction target to be removed	Annual	Reference value adjusted periodically

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
P9 - Off-Site Heat Generation	Emissions Off-Site Heat Generation = Heat * EF_H Where: EF_H = Industrial Heat Benchmark					
	Emissions $_{\text{Off-Site Heat Generation}}$	t CO_2e	N/A	N/A	N/A	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
	Quantity of heat imported by the emission offset project / Heat	GJ	Measured	Direct measurement of the quantity of heat used by the CO_2 sequestration emission offset project	Annual	Continuous metering is standard for boundary transfer
	Benchmark for Industrial Heat Generation/ EF_H	t CO_2e / GJ	N/A	Regulated facilities 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	Annual	Established industrial heat benchmark as listed in Provincial GHG Regulation

P10 - On-Site Heat and Electricity Generation	$Emissions_{\text{On-Site Heat and Electricity Generation}} = \sum (Fuel_{CCS} * EF\ Fuel_{i, CO2, CH4, N2O}) * GWP_{CO2, CH4, N2O}$ Where: $Fuel_{CCS} = (Heat_{CCS} / Heat_{T}) * Fuel_{H} + (Elec_{CCS} / Elec_{T}) * Fuel_{E}$ *If direct measurement is not available, an optional calculation is provided:* $Fuel_{H} = Fuel_{H\,\&\,E} * (Heat_{T}/e_{H}) / (Heat_{T}/e_{H} + Elec_{T}/e_{E})$ *Where: e = efficiency* $Fuel_{E} = Fuel_{H\,\&\,E} - Fuel_{H}$					
	Emissions On-Site Heat and Electricity Generation	t of CO2e	N/A	N/A	N/A	Quantity being calculated based on quantity of heat and power sourced from on-site cogeneration facilities
	Proportionate Volume of Fossil Fuels Consumed to Generate Heat and Power at On-Site Generation Facilities for Use by the CCS Project / $Fuel_{CCS}$	L/ m^3/ Other	Calculated	Calculated relative to the metered quantities of thermal energy and electricity delivered to the carbon capture and storage project from connected heat and power generation facilities.	Monthly	Allocation of Project Emissions based on proportion of total energy output from the cogeneration unit that is supplied to the carbon capture and storage project is appropriate given that multiple energy users may source thermal energy or electricity from a single combined heat and power plant. Direct metering of thermal energy and electricity is appropriate.

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	Volume of Fossil Fuels Consumed to Generate Heat at On-Site Generation Facilities for Use by the CCS Project /	L/ m^3/ Other	Measured	Direct measurement of the volume of fossil fuels consumed at the heat and power generation facility and/or other direct connected facilities that provide heat to the carbon capture and storage project.	Continuous metering	Continuous direct metering represents the industry practice and the highest level of detail.
	Fuel $_H$		Calculated	Calculated based on heat generation efficiency of generation unit.	Monthly	Calculated according to best practice guidance.
	Volume of Fossil Fuels Consumed to Generate Electricity at On-Site Generation Facilities for Use by the CCS Project / Fuel $_E$	L/ m^3/ Other	Measured	Direct measurement of the volume of fossil fuels consumed at the heat and power generation facility and/or other direct connected facilities that provide power to the carbon capture and storage project.	Continuous metering	Continuous direct metering represents the industry practice and the highest level of detail.
			Calculated	Calculated based on heat generation efficiency of generation unit.	Monthly	Calculated according to best practice guidance.
	Total Volume of Fossil Fuels Consumed to Generate Heat and Power at the Combined Heat and Power Generation Facilities / Fuel $_{H \& E}$	L/ m^3/ Other	Measured	Direct measurement of the volume of fossil fuels consumed at the combined heat and power generation facility and/or other direct connected facilities that provide heat and/or power to the carbon capture and storage project.	Continuous metering	Continuous direct metering represents the industry practice and the highest level of detail.

Project/ Baseline Sources/ Sinks	**Parameter / Variable**	**Units**	**Measured/ Estimated**	**Method**	**Frequency**	**Justification for Measurement or Estimation and Frequency**
	Total Quantity of Thermal Energy Supplied to the CCS Project from Generation Facilities / Heat $_{CCS}$	GJ	Measured	Direct metering of quantity of thermal energy received by the carbon capture and storage project from connected heat and power generation facilities (e.g., from dedicated cogeneration facilities, other industrial facilities etc.). Metering of the thermal energy should account for the type of heat transfer medium (steam, hot water, oil, etc.) and the net heat transfer based on mass/volume flow rates of the heat transfer medium to and from the carbon capture and storage equipment (e.g., accounting for the enthalpy of feedwater, boiler blow down and condensate return), temperatures, pressures for superheated steam and other relevant thermodynamic properties as necessary.	Continuous metering	Direct metering of thermal energy is standard practice when thermal energy is provided to a user under a contractual agreement. Frequency of metering is highest level possible. Accounting for the net heat transfer from the heat distribution system based on the specific temperatures and pressures of the heat transfer medium is consistent with best practices.
	Total Quantity of Electricity Supplied to the CCS Project by Generation Facilities / Elec $_{CCS}$	GJ	Measured	Direct metering of the quantity of electricity delivered to the carbon capture and storage Project from third party generation plants or other direct connected power generation facilities. Note that grid electricity usage is accounted for under a separate source/sink and should not be included in this calculation.	Continuous Metering	Continuous direct metering represents the industry practice and the highest level of detail.

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	Total Quantity of Thermal Energy Supplied to End Users by the Generation Facility in the Project Condition / $Heat_T$	GJ	Measured	Direct metering of quantity of thermal energy delivered to all end users by the generation plant (including the carbon capture and storage facilities). Metering of the thermal energy should account for the type of heat transfer medium (steam, hot water, oil, etc.) and the net heat transfer based on mass/ volume flow rates of the heat transfer medium to and from the capture facility (e.g., accounting for the enthalpy of feedwater, boiler blow down and condensate return), temperatures, pressures for superheated steam and other relevant thermodynamic properties as necessary.	Continuous Metering	Direct metering of thermal energy is standard practice when thermal energy is provided to a user under a contractual agreement. Frequency of metering is highest level possible. Accounting for the net heat transfer from the heat distribution system based on the specific temperatures and pressures of the heat transfer medium is consistent with best practices.
	Total Quantity of Electricity Supplied to End Users by the Generation Facility in the Project Condition / $Elec_T$	GJ	Measured	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 the carbon capture and storage facilities, the regional electricity grid and an industrial system designation.	Continuous Metering	Continuous direct metering represents the industry practice and the highest level of detail.

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
	Efficiency of Heat Generation at On-site Generation Unit / e_H	-	Estimated	Estimated based on total quantity of thermal energy output from generation unit and input energy content of fuels combusted by the generation unit. If a site-specific heat generation efficiency is unavailable, use a default efficiency of 80%.	Annual	Estimation is reasonable given consistency of generation unit operations.
	Efficiency of Electricity Generation at On-site Generation Unit / e_E	-	Estimated	Estimated based on total quantity of electricity output from generation unit and input energy content of fuels combusted by the generation unit. If a site-specific electric efficiency is unavailable use a default efficiency of 35%.	Annual	Estimation is reasonable given consistency of generation unit operations.
	Emissions $_{\text{Carbon Capture and Storage Facility Operation}}$	t of CO_2e	N/A	N/A	N/A	Quantity being calculated based on quantity of fossil fuels used for inspection and maintenance of carbon capture and storage facilities.
	Volume of Each Type of Fuel Used CCS Facility Operation/ Fuel $_i$	L / m^3 / other	Estimated	Volumes of fuel consumed by each piece of equipment used during the operating activities of the CCS facility may be estimated.	Annual	Quantity being estimated in aggregate form as fuel used at CCS facility is likely aggregated for each source.
	$GWP_{CO2,CH4,N20}$	Unitless	Estimated	As per the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Section 1(3) of TIER requires that offset projects use the GWPs published in the most recent version of the Standard.

Project/ Baseline Sources/ Sinks	**Parameter / Variable**	**Units**	**Measured/ Estimated**	**Method**	**Frequency**	**Justification for Measurement or Estimation and Frequency**
P18 - Venting at Injection Well Sites	$Emissions_{Venting\ at\ Injection\ Well\ Sites} = \sum (Vol._{Gas\ Vented} * \%_{CO2,\ CH4,\ N2O} * \rho_{CO2,\ CH4,\ N2O}) * GWP_{CO2,\ CH4,\ N2O}$					
	$Emissions_{Venting\ at\ Injection\ Well\ Sites}$	t of CO_2e	N/A	N/A	N/A	Quantity being calculated.
	Volume of Vent Gas / $Vol._{Gas\ Vented}$	L / m^3 / other	Estimated	Volume should be estimated based on the pressure, length and diameter of the pipe being serviced.	Per event	This vented gas is downstream of the injection meter during maintenance blowdowns and should be as frequent as the maintenance event.
	Composition in Vent Gas / $\%_{CO2,CH4,N2O}$	%	Measured	The gas composition shall be directly measured downstream of the capture and processing equipment and as close as possible to the point where CO_2 is injected into the deep saline aquifer.	A minimum of daily samples averaged monthly on volumetric basis	Composition may vary throughout the injection of gas stream. Frequent gas composition measurement is reasonable for operation of an injection facility.
	Density of Vent Gas / $\rho_{CO2,CH4,N2O}$	t/m^3	Estimated	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 pressure or temperature used for the specific meter calibration.	N/A	Densities must be used consistently throughout project.
	$GWP_{CO2,CH4,N20}$	Unitless	Estimated	As per the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Section 1(3) of TIER requires that offset projects use the GWPs published in the most recent version of the Standard.

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
P19 - Fugitives at Injection Well Sites	*$Emissions_{\text{Fugitives at Injection Well Sites}} = \sum (Fitting_i * ER_{\text{Fitting } i}) + \text{Other Fugitive Releases}$*					
	$Emissions_{\text{Fugitives at Injection Well Sites}}$	t of CO_2e	N/A	N/A	N/A	Quantity being calculated.
	Other Fugitive Releases	t of CO_2	Estimated	Engineering estimate.	Per occurance	This is from unintended/unplanned events, and accounts for CO_2 released after the meter and wellbore but not from the storage container. Estimated based on the most detailed information available.
	Number of Fittings after Injection Meter / $Fitting_i$	N/A	Estimated	Project-specific design.	Once	Estimated based on the number of fittings after the injection meter and above the subsurface.
	Emission Rate for Fitting / $ER_{\text{Fitting } i}$	t of CO_2e /fitting/ year	Estimated	Emission rate based on industry best practices for determining typical fitting emissions based on actual field equipment (fitting sizes, types, operating pressures and gas properties).	Annual	Estimates made for project specifics represent the most accurate means.

P20 - Emissions from a Reversal	$Emissions_{\text{Subsurface to Atmosphere}} = Mass\ CO_2e_{\text{leaked}}$					
	Mass of CO_2e leaked from the Subsurface to Atmosphere/ Mass CO_2e_{leaked}	t of CO_2e	Estimated	If a leak event occurs, the mass of CO_2e 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.	N/A	Estimation would be required for reporting to The Alberta Energy Regulatory authority. 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.

Project/ Baseline Sources/ Sinks	Parameter / Variable	Units	Measured/ Estimated	Method	Frequency	Justification for Measurement or Estimation and Frequency
P21 - Loss, Disposal or Recycling of Material Used	$Emissions_{\text{Loss, Disposal or Recycling of Material Used}} = \sum (Vol.\ Used_i * EF\ Used_{i\ CO2,\ CH4,\ N2O}) * GWP_{CO2,\ CH4,\ N2O}$					
	Emissions $_{\text{Loss, Disposal or Recycling of Material Used}}$	t of CO_2e	N/A	N/A	N/A	Quantity being calculated in aggregate based on quantity materials used for the carbon capture and storage operations.
	Total Volume of Material Lost, Disposed or Recycled from the Carbon Capture and Storage Facility/Vol. Used $_i$	L/ m^3/ Other	Estimated	Estimation of the volume of material inputs lost, disposed or recycled for the carbon capture and storage project.	N/A	Engineering report will specify the volume of material input lost, disposed or recycled for an appropriately sized carbon capture and storage facility. Represents most reasonable means of estimation. Loss, disposal or recycling estimates for the emission factors for the materials used.
	Emissions factor for each type of material input / EF Used $_{i\ CO2,\ CH4,\ N2O}$	t CO_2e per L / m^3/ other	Estimated	Project-specific design.	Annual	Production and delivery estimates for the emission factors for the material inputs.

***Table 7**: Common Quantification Variables*

Parameter / Variable	Units	Measured / Estimated	Metho d	Frequency	Justify measurement or estimation and frequency
Total heat produced by the facility / H	GJ	Measured	Total quantity of heat produced by the facility is determined through direct metering.	Annual calculation of continuous metering	Continuous direct metering represents the industry practice and the highest level of detail.
Higher heating value / HHV	GJ/L, m3 or other	Measured	Measured by a third party gas analysis or calculated based on gas compositions. Units for HHV and Emission Factor for Fuel must align.	Annual	Frequency of metering provides for reasonable diligence.
CO_2 emission factor for each type of fossil fuel combustion/ EF Fuel $_{i\ CO2}$	t CO_2e per L, m^3 or other	Estimated	See Technical Guidance for Completing Specified Gas Baseline Emission Intensity Applications for Table 5: Emission Calculation Methods Acceptable to Alberta Environment and Parks and/or latest version of Carbon Offset Emission Factor Handbook.	Annual	Reference values are adjusted periodically use the most current version.
CH_4 emission factor for each type of fossil fuel combustion/ EF Fuel $_{i\ CH4}$	t CO_2e from kg CH_4 per L, m^3 or other	Estimated	See Technical Guidance for Completing Specified Gas Baseline Emission Intensity Applications for Table 5: Emission Calculation Methods Acceptable to Alberta Environment and Parks and/or latest version of Carbon Offset Emission Factor Handbook.	Annual	Reference values adjusted periodically use the most current version.
N_2O emission factor for each type of fossil fuel combustion / EF Fuel $_{i\ N2O}$	t CO_2e from kg CH_4 per L, m^3 or other	Estimated	See Technical Guidance for Completing Specified Gas Baseline Emission Intensity Applications for Table 5: Emission Calculation Methods Acceptable to Alberta Environment and Parks and/or latest	Annual	Reference values adjusted periodically Use the most current version.

Parameter / Variable	Units	Measured / Estimated	Method	Frequency	Justify measurement or estimation and frequency
			version of Carbon Offset Emission Factor Handbook.		
Total quantity of fuel consumed / Fuel $_i$	m^3/ MJ/ kg or other	Measured	Direct measurement of the quantity of fossil fuels consumed at each component of the carbon capture and storage project.	Continuous metering	Quantity being calculated in aggregate based on quantity of fossil fuels used.
		Estimated	Calculate the mass/volume of fuel used for heat or electricity production. Conversions from energy to fuel quantities should use the higher heating value of the fuel. Energy use should be either measured or calculated based on conservative estimate for equipment duty and load.	Annual	Annual fuel consumption estimate should be completed in the absence of direct metering for fuel consumption. Maximum power consumption rates should be used to estimate fuel consumption with higher heating values.
$GWP_{CO2,CH4,N20}$	Unitless	Estimated	As per the Standard for Completing Greenhouse Gas Compliance and Forecasting Reports	N/A	Section 1(3) of TIER requires that offset projects use the GWPs published in the most recent version of the Standard.

5.0 Data Management

All emission offset projects must be supported with 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 GHG Statements 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 and sequestration 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 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 CO_2 from the CO_2 capture, transportation and injection activities that are outlined in this protocol. This first category applies to all projects and the requirements are discussed further below.

The second category pertains to monitoring activities to ensure that the CO_2 injected into sequestration schemes is permanently contained within the targeted geologic storage zone(s). Each project must comply with the relevant Directives and Regulations and any specific monitoring requirements included in the scheme approval issued by the AER.

Approvals to operate a sequestration 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 CCS 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 Directive 017 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. Project Developers shall require 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

For the purposes of emission reduction quantification under this protocol 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. These monitoring requirements should not be conflated with the monitoring, measurement and verification requirements established under D065.

At a minimum the monitoring plan shall stipulate and include:

- The frequency of data acquisition;
- A record keeping plan;
- Identification of key instrumentation;
- Validation activities to prove the accuracy of gas composition measurements (see Table 8 for additional guidance).
- 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:
    - Energy inputs required to capture, dehydrate, compress, transport, inject and store CO_2 including:
        - Direct fuel inputs; and
        - Indirect energy inputs or other parasitic loads (e.g., heat or electricity consumption);
- Quantity and concentration of CO_2 sold to third parties including sufficient measurements to support data required;
    - Quantity and concentration of CO_2 injected; and
    - 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.

Additional measurements may be made to support quantification purposes. At each of the measurement points, the mass of the gas stream must be determined based on the volumetric or mass flow, and composition of the gas stream.

Table 8 provides guidance on the measurement and monitoring requirements. It is also necessary to monitor the incremental energy inputs (fossil fuels and electricity) required to operate the carbon capture and storage project. The general monitoring requirements for fossil fuel and electricity inputs are listed in Table 9.

5.1.3 Physical System Measurement Principles

A single physical system for capturing and/or transporting and sequestering CO2 may support one or more emission offset project. The following principles must be considered for physical systems when undertaking emissions accounting in hub scenarios:

- At least one capture site or CO_2 intake point and one or more injection well is required for an eligible sequestration project under this protocol.

- The offset plan should include all physically connected elements where CO_2 could be directed for future flexibility within Hub projects.
- Project reporting can cover a single CO_2 route even if many are physically possible as long as annual balancing requirements to physical totals are met.
- All emission from the physical system must be captured in TIER for conservativeness unless physically serving single capture or injection points (that are not shared), or a reversal which are exclusively being reported outside of TIER.

5.1.4 Balancing Confirmation for Physical Systems

Projects (TIER or otherwise) need to total to the physical network (reported on annually) other than emissions which may be double counted. Balancing confirmation must be carried out for the following quantities:

- Total CO_2 entering the system
- Total injected CO_2
- Total emissions must be greater or equal to total physical emissions
- Total electricity imported/exported
- Total heat imported/exported

Prorating should be done on CO2 shares unless mutually agreed upon by all impacted projects (TIER or otherwise).

Reporting for the physical system where it is not represented by a single offset project should be verified annually based on calendar year and will be posted alongside documents for each offset project which it supports. Emission offset projects can report on a more frequent basis as long as true-up to annual physical totals occurs.

5.1.5 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.

Volumes of CO2 produced and injected within the project boundary must be separately accounted for.

Flow meters must be placed based on manufacturer recommendations.

Flow meters should be located at the input to the 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 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 CO_2 flow meters must be calibrated in accordance with AER Directive 17 under the same annual calibration schedule as is advised for natural gas chain of custody meters. And
- Ownership transfer must be clearly documented for CO_2 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.

5.1.6 Monitoring and Reservoir Management Plan for Containment Assurance

Monitoring, measurement and verification requirements, based on the characteristics of the reservoir and sequestration scheme, are outlined by the AER as part of the D065 scheme approval. It requires each sequestration 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:

- **Directives 007 and 017**: requirements for measuring and reporting the amounts of CO_2 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 60**: requirements for flaring, incinerating, and venting in Alberta at all upstream petroleum industry wells and facilities: and
- **Directive 065**: application requirements for a sequestration scheme.

As required in the D065 scheme approval by the AER, the annual progress report will provide containment assurance specific to the targeted geologic storage zone(s). 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 targeted geologic storage zone(s), 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 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 C). 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 D065 scheme approval area must be reported in the Containment Assurance Report. Operational containment assurance may include results from other monitoring undertakings if other parameters are available from the operator.

Containment assurance and reservoir management shall be reviewed periodically by the operator, and the 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 CO_2;
- Addition or abandonment of injection zones;
- Addition or abandonment of injector wells;
- Development of reservoirs which are located above or below the project reservoir;
- Discovery of CO_2 beyond the boundary of the targeted CO_2 geologic storage zone(s); or
- Removal or release of CO_2.

The D065 scheme approval requires the project operator to develop a closure plan for the sequestration project that specifies criteria for issuance of a closure certificate. The plan should specify:

- The closure process and anticipated timing;
- Monitoring consistent with AER requirements for sequestration 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 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.

5.1.7 Missing Data Procedures

If an emission offset project developer discovers that there is missing data, the procedures for estimating missing data set out in section 17.5.2 of the Alberta Quantification Procedures (AQM) must be followed with consideration for conservativeness to determine an appropriate substitute for missing data required under the protocol. The project developer must identify the missing data procedure that will be followed in the offset project report and be part of the verification for professional review for reasonableness.

5.2 Required Project Documentation

Documentation requirements for the emission offset project are as follows:

- The sequestration scheme number;
- Energy use records for capture, transport and sequestration scheme operations;
- Concentration and measurement records of injected CO_2;
- A completed Report Balance Sheet for CO_2 from Appendix C that includes:
  - The gross quantity of New CO_2 injected into the scheme CO_2;
  - The project emissions for the current reporting period;
  - The net quantity in tonnes, of CO_2 stored by the project (CO_2 in place);
- Documentation for project eligibility requires at a minimum:
- The name and contact information of the emission offset project developer(s);
- Evidence of the CO_2 injection start date;
- Evidence and explanation of ownership (for each emission offset project);
- All applicable permits for project condition, where relevant;
- A suitable monitoring, measurement and verification plan as defined by AER requirements;
- Evidence that the project results in net geological sequestration located in Alberta including legal land location and GPS coordinates of the site via the inventory; 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.

5.3 Record Keeping and Project Archives

Alberta Environment and Protected Areas 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 or part of the activity, the project developer must maintain sufficient records to support the whole of 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 government third party assurance provider, or Director 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 where emission factors came from;
- 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 Directive 017 requirements and the Quantification Methodologies under Alberta greenhouse gas regulations, and the Specified Gas Reporting Regulation.
- 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 previous verification or reverification records with immaterial findings addressed.

In order to support the third-party verification and 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/or 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.

Table 8: *Measurement and Monitoring Guidance for Injected Gas*

Variable	**Units of Measurement**	**Measurement Frequency**	**Additional Guidance**
Flow rate of gas stream	L / m^3 / tonnes other	Continuous measurement of the gas flow rate, gas composition, and gas density where continuous measurement is defined as a minimum of one measurement every 15 minutes.	• Meter readings may need to be temperature and pressure compensated such that the meter output is set to standard reference temperatures and pressures. Estimates of composition and density are not permissible; • Flow meters must be placed based on manufacturer recommendations: o 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 o Flow meters should be as close as possible to the injection wellheads to ensure accurate measurement of the injected volumes; • Flow meters must be calibrated according to manufacturer specifications. Meters must be checked/calibrated at regular intervals according to these specifications and industry standards; and • Ownership transfer must be clearly documented for CO_2 transferred (third party injection activity).
Concentration of gas stream	%	Continuous measurement of the gas composition and density where continuous measurement is defined as a minimum of one measurement every 15 minutes.	The gas composition shall be metered downstream of the capture and processing equipment or upstream of the injection field at a custody transfer point, while the volume is measured as close as possible to the point where CO_2 is injected into the targeted CO_2 storage zone(s). The Project must validate the accuracy of selected analyzers. Validation may include a combination of laboratory analysis of samples, performance specification tests from the Alberta Continuous Emission Monitoring System (CEMS) Code, and/or statistical analysis. Validation frequency may be managed adaptively. Frequency should be high to start, may be decreased upon consistent validation and subsequently increased upon inconsistent validation.

Table 9: *Measurement and Monitoring Guidance for Energy Inputs*

Variable	Units of Measure	Measurement Frequency	Additional Guidance
Volume of fossil fuels combusted (gaseous)	ft^3 or m^3 or other	Continuous measurement of the gas flow rate where continuous measurement is defined as one measurement every 15 minutes.	• The flow meter readings must be corrected for temperature and pressure. Density estimates used for emission quantification purposes must be adjusted to corrected standardized temperatures and pressures; • Flow meters shall be placed based on manufacturer recommendations and shall operate within manufacturers specified operating conditions at all times; and • Flow meters must be calibrated according to manufacturer specifications and shall be checked and calibrated at regular intervals according to these specifications.
Volume of fossil fuels combusted (liquid or solid)	L, m^3 or other	Reconciliation of purchasing records on a quarterly basis and inventory adjustments as needed.	Volume or mass measurements are made at purchase or delivery of the fuel. Reconciliation of purchase receipts or weigh scale tickets is an acceptable means to determine the volumes of fossil fuels consumed to operate the carbon capture and storage project.
Electricity Consumption	MWh	Continuous measurement of electricity consumption or reconciliation of maximum power rating for each type of equipment and operating hours.	• Electricity consumption must be from continuously metered data wherever possible; however, in certain cases other loads may be tied into the same electricity meter. Where this occurs, estimates with justification are required. In these cases, the maximum power rating of each piece of equipment is used in conjunction with a conservative estimate of operating hours to estimate the electricity consumption; and • Electricity meters must be calibrated by an accredited third party in accordance with manufacturer specifications.

6.0 References

Alberta Energy Regulator. Directive 007 Volumetric and Infrastructure Requirements. March 27, 2023.

Alberta Energy Regulator. Directive 017 Measurement Requirements for Oil and Gas Operations. March 17, 2022.

Alberta Energy Regulator. Directive 020 Well Abandonment. September 5, 2023.

Alberta Energy Regulator. Directive 051 Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements. April 28, 2023.

Alberta Energy Regulator. Directive 060 Upstream Petroleum Industry Flaring, Incinerating, and Venting. April 6, 2022.

Alberta Energy Regulator. Directive 065 Resources Applications for Oil and Gas Reservoirs. July 27, 2023.

Alberta Environment and Protected Areas. Alberta Emission Offset System Quantification Protocol for Enhanced Oil Recovery Version 2.0. January 2022. |

American Petroleum Institute. International Petroleum Industry Environmental Conservation Association. Oil and Natural Gas Industry Guidelines for Greenhouse Gas Reduction Projects. Part II: Carbon Capture and Geological Storage Emission Reduction Family. June 2007.

Canadian Standards Association. Z741 Geological Storage of Carbon Dioxide. December 2012.

Det Norske Veritas. CO2QUALSTORE Guidelines for Selection and Qualification of Site and Projects for Geological Storage of CO_2. February 2010.

Government of Alberta. Carbon Offset Emission Factors Handbook, Version 3.1, January 2023.

Government of Alberta. Technical Guidance for the Assessment of Additionality, Version 1.0. May 2018

Government of Alberta. Standard for Greenhouse Gas Emission Offsets Project Developers, Version 3.2. April 2023

International Energy Agency, presentation on Monitoring and Reporting Guidelines for Injection and Storage, January 2014

International Organization for Standardization. ISO 14064-2:2019 Specification with Guidance at the Project Level for Quantification, Monitoring and Reporting of GHG Emission Reductions and Removal Enhancements, 2019

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

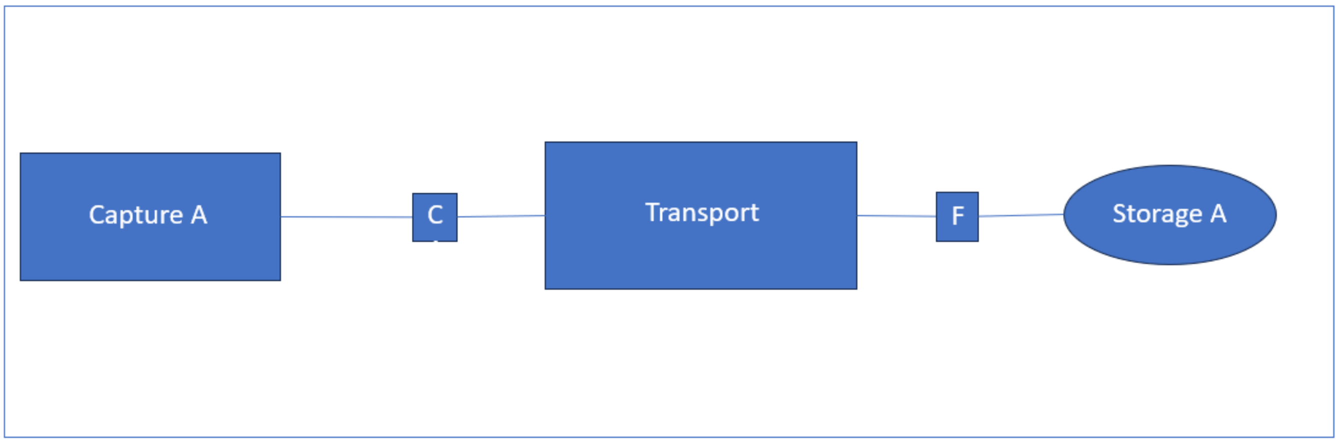
The United Nations Framework Convention on Climate Change. Implications of the Inclusion of Geological Carbon Dioxide Capture and Storage as CDM Project Activities Draft Final Report - Annex 1, 2009

Appendix A: CO2 Injection by Multiple Developers

Guidance for the Injection of CO_2 by Multiple Networks

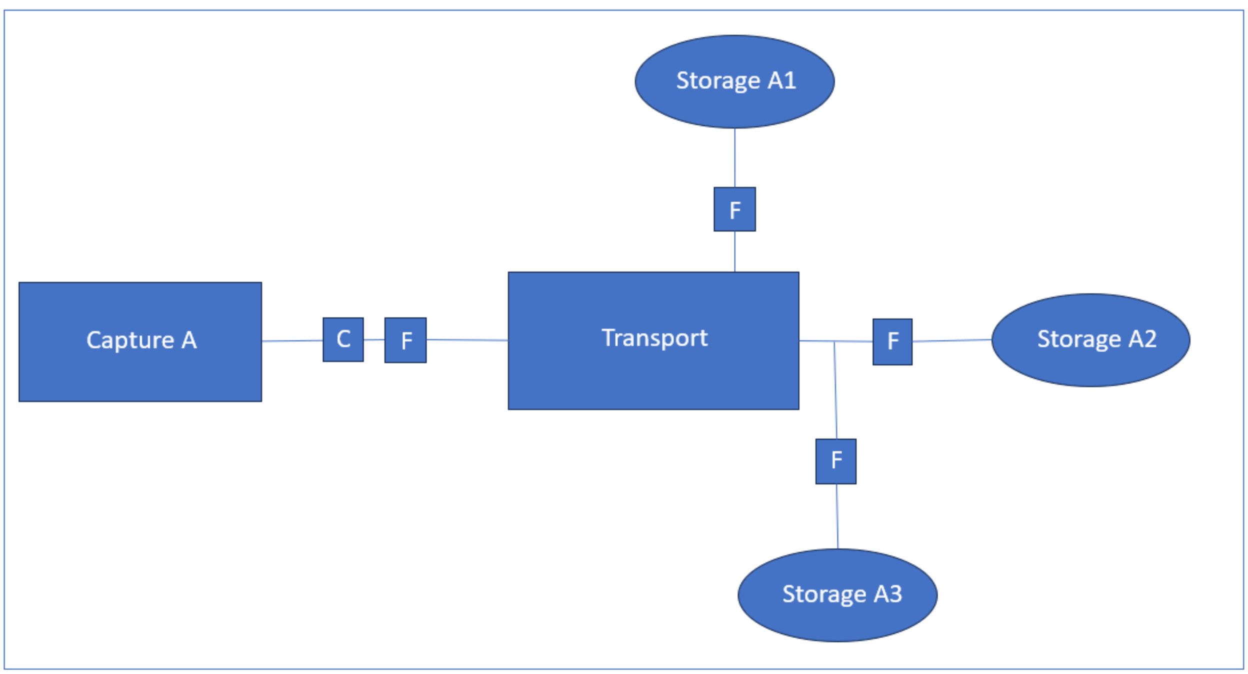
The following provides guidance for projects in which CO2 is being transported for use in CO2 sequestration schemes. Gas flow/quantity measurement and CO_2 concentration measurement/sample points must be carefully considered in complex/multiple networks. Scenarios 1 through 4 depict the fluid flow measurement and CO_2 concentration measurement/sample points in a variety of physical network project configurations from simple to more complex.

Scenario 1: Single Capture Single Storage



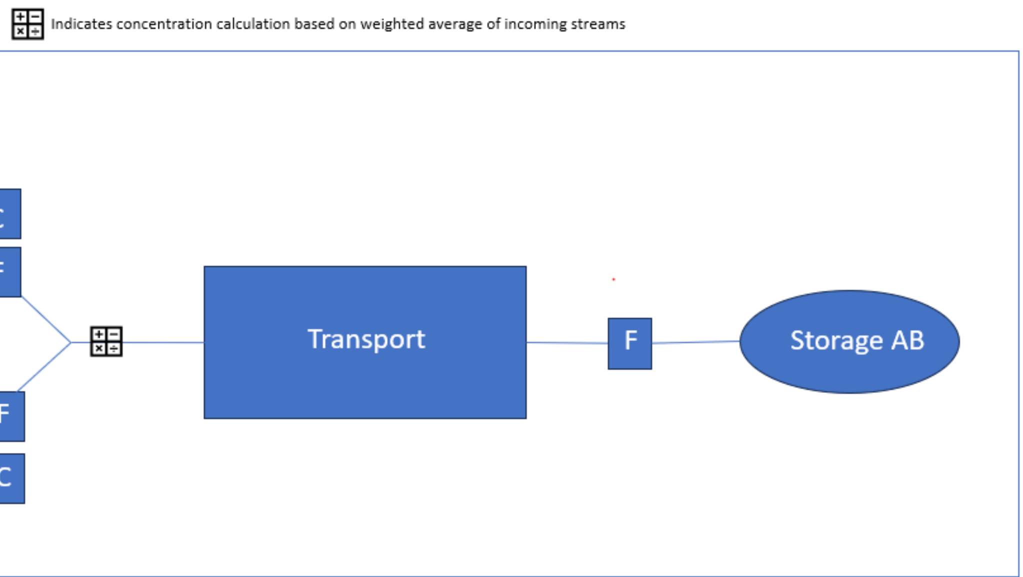
Must measure CO_2 concentration or gas composition (C). The sample point may be downstream of capture or at the storage location (injection well). Must measure gas quantity (F) at storage location (injection well).

Scenario 2: Single Capture Multiple Storage



Must measure CO_2 concentration or gas composition (C) at either at the point of capture or points of storage. Not required to measure both locations. Must measure gas quantity (F) at the point of storage. 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 where n is the number of input and storage points. Measured CO_2 concentration at the inlet to transport will be equal to the CO_2 concentration at storage.

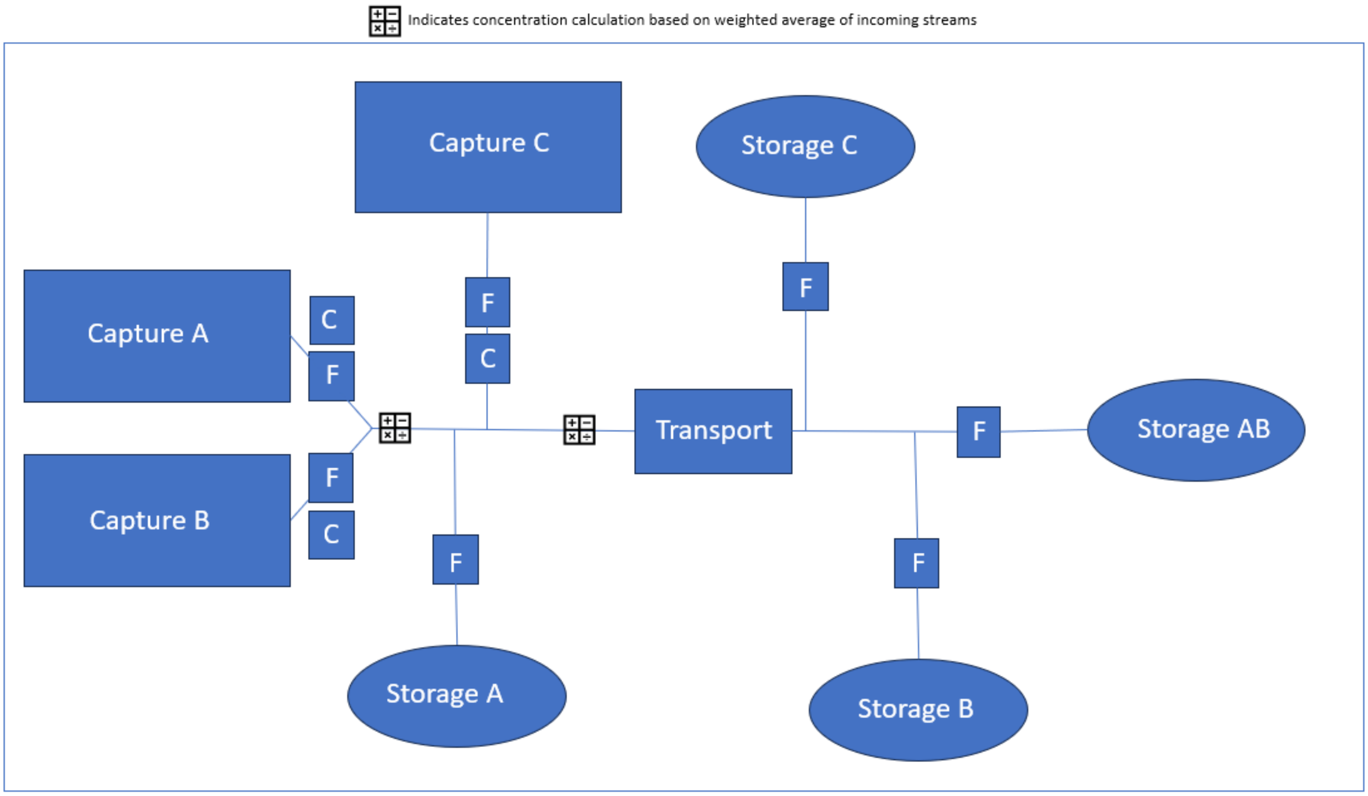
Scenario 3:Multiple Capture Single Storage



Must measure CO_2 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 CO_2 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. The CO_2 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



Must measure CO_2 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 CO_2 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. CO_2 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. For a complex CO_2 system or network, the emissions from that network must be included in 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.

Requirements for Complex CO_2 Networks

- Capture facility operators will measure the CO_2 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 that fall within the offset project boundary.
- Transport (pipeline operator) will maintain an auditable and verifiable custody transfer system tracking mass of CO_2 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.
- Sequestration operators will measure all data points required to quantify the emissions of the CO_2 sequestration operations as well as the quantities injected.

Appendix B: Guidance for Estimating Emissions from Subsurface Equipment and Targeted Geologic Zone(s)

For the quantification of P20 Emission from Subsurface to Atmosphere, the quantity of emissions leaked from the subsurface equipment or targeted geologic zone(s) to atmosphere for each of the leakage events must be estimated with a maximum overall uncertainty of ±7.5% over the reporting period using the absolute value of the uncertainly. 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:

$$CO_{2,\ Reported}\ [t\ CO_2] = CO_{2,\ Quantified}\ [t\ CO_2] * (1 + (|Uncertainty_{\ System}\ [\%]|/100))$$

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 even 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) International Energy Agency presentation on Monitoring and Reporting Guidelines for Injection and Storage[2]; and 2) Clean Development Mechanism United Nations Framework Convention on Climate Change[3].

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[2] International Energy Agency, presentation on Monitoring and Reporting Guidelines for Injection and Storage, January 2014, which states: “Maximum ±7.5% uncertainty, if exceeded then add ‘uncertainty Adjustment’”

[3] Implications of the Inclusion of Geological Carbon Dioxide Capture and Storage as CDM Project Activities Draft Final Report - Annex 1 Proposed Agenda - Annotations pp 44, Clean Development Mechanism of The United Nations Framework Convention on Climate Change, 2009

Appendix C: Carbon Capture and Sequestration 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 prior to the issuance of a closure certificate (it is not required to be part of project report submitted to the Registry). The time period must match the Annual Progress Report submitted to the AER. The AER may also flag any non-compliance events to Alberta Environment and Protected Areas.

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 a carbon capture and sequestration 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) of the CO_2.

Reversals are defined in Section 1.5. If the emission offset project developer is not able to provide evidence to demonstrate containment, the project developer must quantify the reversal as set out in section 1.5.
The emission offset project developer may be a different entity than the sequestration tenure holder, as administered by Energy and Minerals. The containment assurance report should be authored and submitted by the sequestration tenure holder. If there are more than one tenure holders associated with an emission offset project, each tenure holder must submit a containment assurance report.

1.0 Project Identification:

Reporting on Calendar Year:
Project Name and ID:
Emission Offset Project Developer: Authorized Project Contact:

Prepared by:
Submission Date:

2.0 D065 Scheme Approval Number:

2.2 Assurance of Containment:

2.3 Mass of CO_2 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.

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

Conclusion
The total injected CO_2 for the calendar year 20XX is ________ tonnes.

2.4 Migration of Subsurface CO_2

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:
Provide evidence no loss of containment has occurred.

If a loss of containment has occurred, provide quantification of CO2 volumes that have reached, or will reach the atmosphere. Provide evidence the loss of containment has been or will be remediated.

If remediation of the loss of containment is not possible, provide evidence of an independent third-party review and determination of whether or not it if foreseeable the loss of containment will result in CO2 reaching the atmosphere within 100 years.

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 CO_2 injected into the project area.

There were _________ tonnes of CO_2 released due to loss of containment.

Signature of designated authority of emission offset project developer:

____

Name:
Title:
Contact email:
Dated:

Appendix D: Balance Sheet for Projects Against Physical System Accounting

Note physical system could include more than one hub/sequestration location if physically interconnected. Additional projects to be added as needed.

Physical system/hub name:		
Time period:		
Verification date:		
Total CO_2 entering:		tonnes
Total CO_2 injected:		tonnes
Total period emissions:		tonnes
Injected CO_2 originating within the project:		tonnes
Total net electricity import:		MWh
Total net heat import:		GJ
TIER offset project name:		
TIER offset project id:		
Time period:		
Verification date:		
Project CO_2 entering:		tonnes
Project CO_2 injected:		tonnes
Total Project emissions:		tonnes
Injected CO_2 originating within the project:		tonnes
Total net electricity import:		MWh
Total net heat import:		GJ
AEOR TIER offset project name:		
AEOR TIER offset project ID:		
Time period:		
Verification date:		
Project CO_2 entering:		tonnes
Project CO_2 injected:		tonnes
Total Project emissions:		tonnes
Injected CO_2 originating within the project:		tonnes
Project net electricity import:		MWh
Project net heat import:		GJ
Non-TIER project name:		
System/market:		
Project ID:		
Time period:		
Verification date:		
Project CO_2 entering:		tonnes
Project CO_2 injected:		tonnes

Total Project emissions:		tonnes
Injected CO_2 originating within the project:		tonnes
Project net electricity import:		MWh
Project net heat import:		GJ
Project totals		
Total CO_2 entering:		tonnes
Total CO_2 injected:		tonnes
Total Projects emissions:		tonnes
Injected CO_2 originating within the projects:		tonnes
Total net electricity import:		MWh
Total net heat import:		GJ