QUANTIFICATION PROTOCOL FOR THE CAPTURE OF CO_2 AND PERMANENT STORAGE IN SALINE GEOLOGICAL FORMATIONS

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Identification of Protocol Developer

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1 Introduction

The capture and storage of carbon dioxide (CO_2) has been widely recognized as an important greenhouse gas (GHG) emission reduction technology. In Alberta, carbon capture and storage (CCS) has been identified as a key technology to enable the province to meet greenhouse gas emission reduction targets as outlined in Alberta's 2008 Climate Change Strategy.[1] The Alberta climate change strategy anticipates carbon capture and storage projects to contribute 139 million tonnes (Mt) of CO_2-equivalent greenhouse gas reductions per year relative to business as usual by 2050. As such the development and implementation of CCS technologies is of major importance to Alberta and there is a need to develop accurate quantification methodologies that can be used by project developers to quantify project-based GHG reductions with a reasonable level of assurance to generate compliance grade emission offsets.

The development of this quantification protocol was initiated by Shell Canada to support the quantification of GHG emission reductions from the proposed Quest CCS Project. Consistent with other government-approved offset system quantification protocols in Alberta, the scope of this protocol is not limited to a single project; however, some of the technologies and processes associated with the Quest CCS Project have been described herein for illustrative purposes. A brief description of the Quest CCS Project is provided below and a more detailed description of the main process elements is provided later in the document.

Shell, on behalf of the Athabasca Oil Sands Project (AOSP), a joint venture between Shell Canada Energy (60%), Chevron Canada Limited (20%), and Marathon Oil Sands L.P. (20%) is planning to implement a carbon capture and storage project ("The Quest CCS Project") to reduce GHG emissions associated with hydrogen production from steam methane reformers (SMR) at the Scotford Upgrader and the Scotford Upgrader Expansion facilities, that upgrade bitumen to produce synthetic crude oil. The Quest CCS Project will result in the capture and storage of up to 1.2 million tonnes per year (Mtpa) of CO_2 from the Scotford Upgrader.

The typical CCS Project consists of three main components:

1. CO_2 capture infrastructure, which usually involves a process modification to the existing facility.
2. A CO_2 pipeline to transport CO_2 from the capture facility to the injection wells.
3. Storage of CO_2 through injection wells, which will inject CO_2 into a deep saline geological formation, for permanent storage.

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[1] http://environment.gov.ab.ca/info/library/7894.pdf

2 Scope and applicability of protocol

2.1 Review of technology/practices

The opportunity for generating GHG emission reductions under this quantification protocol arises from the geological storage of CO_2 that would otherwise have been released to the atmosphere had the CCS project not been implemented. The scope of this protocol is specific to the capture of CO_2 from industrial processes (not related to enhanced oil recovery), the transport of CO_2 via pipeline, and the permanent storage of CO_2 in a deep isolated geological formation. The protocol covers the full CCS chain from capture through compression, transport, injection and storage, but is specific in terms of the type of geological storage reservoir. Non-producing hydrocarbon-containing reservoirs and deep isolated geological formations are included, producing hydrocarbon reservoirs are not included under this protocol, because they are applicable under the existing Enhanced Oil Recovery Quantification protocol.

The proposed protocol is applicable to the capture of CO_2 from various processes including *industrial process emissions*[2] from steam methane reformation method of hydrogen production. Industrial process emissions are regulated under the Alberta Specified Gas Emitters Regulation (SGER), but are not currently subject to a reduction target.

2.2 Greenhouse gases identified/targeted

The implementation of carbon capture and storage projects will primarily reduce carbon dioxide emissions; however, three types of greenhouse gas emissions are quantified in the project condition (e.g. combustion emissions), namely carbon dioxide, methane, and nitrous oxide emissions, as shown in Table 1.

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[2] "*Industrial process emissions* are defined as the direct emissions from an industrial process involving chemical or physical reactions, **other than combustion**, and where the primary purpose of the industrial process is not energy production. Examples of chemical processes resulting in industrial process emissions include steam methane reforming for hydrogen production (e.g. at refineries, bitumen upgraders and fertilizer production facilities), nitric acid production, ethylene oxide production, and cement production." (Specified Gas Emitters Regulation: Technical Guidance Document for Baseline Emissions Intensity Applications, AENV July 18, 2007. http://www.environment.gov.ab.ca/info/library/7811.pdf)

Table 1: Relevant Greenhouse Gases Applicable to CCS Projects

Specified Gas	Formula	100-year GWP[3]	Applicable to Project
Carbon Dioxide	CO_2	1	✓
Methane	CH_4	21	✓
Nitrous Oxide	N_2O	310	✓
Sulphur Hexafluoride	SF_6	23,900	×
Perfluorocarbons*	PFCs	Variable	×
Hydrofluorocarbons*	HFCs	Variable	×

* A complete list of perfluorocarbons and hydrofluorocarbons regulated under the *Specified Gas Emitters Regulation* is available in Technical Guidance for Offset Project Developers.

The potential for Perfluorocarbons to be used as a tracer gas during injection in the geological formation exists for project developers. An explanation as to why perflurocarbons are not considered relevant greenhouse gases is included in Appendix A. SF_6 and HFCs are not relevant to this protocol.

2.3 Additionality

In general the assessment of additionality for the Quest project and other projects falling under this protocol will follow the requirements set forth by Alberta Environment. These requirements have been developed for the Alberta Offset System[4]. Namely, this protocol will require project developers to demonstrate:

- **Consistency with mandatory laws and regulations**: a test assessing any federal, provincial, or municipal regulation that directly affects or requires the activity, and may be for purposes other than controlling greenhouse gas emissions. Project developers will therefore be required to demonstrate that none of the activities associated with the additionality of the project are required by any law or regulation. The Quest project and all other projects developed under this protocol must demonstrate that all legal and regulatory requirements are met if the project were not to go ahead.

- **Alternative technologies:** assessment of other options available to the project developer that would result in the same end function. These alternatives may have different costs, barriers, technology requirements, and emissions profiles. The protocol developer will need to demonstrate that the activity being proposed results in the lowest greenhouse gas emissions while delivering the same or

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[3] **Global warming potential** or GWP is the relative measure of the warming effect that the emission of a specified gas might have on the Earth's atmosphere calculated as the ratio of the time-integrated radiative forcing that would result from the emission of one kilogram of a given specified gas to that from the emission of one kilogram of carbon dioxide (source: Government of Alberta, Specified Gas Reporting Standard – March 2011: http://environment.gov.ab.ca/info/library/7759.pdf).

[4] An internationally recognized source from the Clean Development Mechanism (CDM) for assessing additionality in offset projects is the *Tool for the demonstration and assessment of additionality* (source: CDM, http://cdm.unfccc.int/methodologies/PAmethodologies/tools/am-tool-01-v5.2.pdf).

comparable level of service as the alternatives. In the case of the Quest project and all other projects developed under this protocol, at least one alternative option must include process emissions emitted to atmosphere.

- **Barrier Analysis:** assessment primarily based on technological, financial, and social limitations. A generic list is provided below, while a more specific analysis is provided in Section 3.1.
  - Technological barriers for example, would require development and installation of new technology to provide the same outcome. In some cases, this technology may not be readily available or may require significant capital investment to install. If the technology is readily available and economic to install, this is not considered a significant barrier and would not be considered additional. CCS technologies are relatively new in industry and in general represent a barrier for the Quest project.
  - Financial barriers occur when there is a negative or extremely long return on investment that affects a company's willingness to invest in the project. Financial additionality is a tool used to differentiate transformative projects from commercially attractive projects that would have gone ahead without the offset program. Due to the large infrastructure investments and long term monitoring costs required for CCS in the Quest project and other potential project using this protocol, a negative return on investment is expected and will likely represent a significant barrier.
  - Social barriers occur when public perception and understanding limits the ability to adopt a new activity. While less common than technological or financial barriers, social barriers may be significant and may be grounds to advance a protocol in the Alberta offset system. Public perception of the long term impacts of CCS in deep underground formations is not necessarily positive and may represent a barrier for the Quest project and other projects developed under this protocol. Public concern around leakage/seepage/migration of the storage plume into other formations affecting ground water or ground level air quality should be demonstrated if social barriers are to be the basis of additionality. Tangible impacts from social barriers on project development would need to be demonstrated.
- **Sector level adoption:** the final test for assessing additionality considers the adoption level of the activity across the affected sector. If adoption levels are low, the above additionality tests hold, and the activity is determined to be additional. If adoption levels are high, the above additionality tests are negated and the activity is determined to be business as usual. In other words, if a significant number of other people have engaged in the same activity, then the arguments for financial, technological, and/or social barriers do not hold true and

it is assumed that remaining members of the sector can also adopt the activity and/or practice change. The Quest project will be the first of its kind and an in-depth sectoral level adoption analysis is not required. All process emissions from major hydrogen production activities for upgrading in the province are currently vented to atmosphere. If the adoption level of this technology increases dramatically, project developers would be required to provide a sector level adoption analysis. Alberta has set 40% adoption as a guide for the minimum threshold as common industry practice.

2.4 Review of existing projects/common practice

The scope of this protocol is intended to build off of the Alberta Offset System *Quantification Protocol for Acid Gas Injection Projects* (May 2008, Version 1) and the *Quantification Protocol for Enhanced Oil Recovery* (September 2007, Version 1). At present the Acid Gas Injection (AGI) Protocol is too specific to sour gas processing operations to be fully applicable to other CCS Projects, and the EOR Protocol is only applicable to projects that inject CO_2 into oil-producing reservoirs.

Projects which capture GHGs off process waste streams and inject into non-producing formations are not covered by the existing protocols under the Alberta system. A new protocol is therefore required to accurately quantify the specific processes intended at the Shell Quest project.

No historical offsets will be claimed under this protocol as no commercial scale CCS projects have been implemented to date in Alberta. Therefore all projects that apply the proposed protocol will meet the Alberta Offset System start date eligibility criterion of January 1, 2002.

3 Applicability to all Alberta offset system criteria

The project must meet the requirements for offset eligibility as specified in the applicable regulation and guidance documents for the Alberta Offset System. The following requirements must be met to confirm eligibility under the Alberta Offset System.

1. The Project captures CO_2 from industrial process emission sources.

2. The Project is applicable to the geological storage of CO_2 emissions in saline geological formations and is not applicable to enhanced oil recovery (EOR) or acid gas injection (AGI) schemes associated with hydrocarbon production operations. Proponents with CO_2-EOR projects or AGI projects should refer to the applicable Alberta Offset System quantification protocols for those activities.

3. The CCS project must be in compliance with all operating permits and relevant regulations in Alberta. In particular, the project must demonstrate compliance with operating permits to demonstrate that the storage of CO_2 will be permanent. Refer to Section 6.0 Monitoring for details on the Measurement Monitoring and Verification plan.

4. The project must meet the requirements for offset eligibility as specified in the Technical Guidance for Offset Protocol Developers (January 2011) and any applicable regulation.

3.1 Barriers

CCS projects face numerous barriers in Alberta and worldwide. For further information on barriers faced by CCS projects in Alberta, refer to the Alberta Carbon Capture and Storage Development Council March 2009 final report titled, *Accelerating Carbon Capture and Storage Implementation in Alberta*.[5] A list of barriers is provided below.

- High capital costs for installation of capture equipment, compressors, pipelines, injection wells, and monitoring infrastructure make CCS projects uneconomic
- The current cost of emitting CO_2 (the baseline condition) is insufficient to make CCS projects economic
- Pure CCS projects have to compete with CO_2-EOR projects which are likely to have more favorable economics provided that appropriate producing reservoirs exist in reasonable proximity to the CO_2 source.
- Significant energy inputs are required to operate capture and compression equipment, resulting in increased operational costs and lower operational efficiencies
- Long term liability may be difficult to accommodate into corporate investment horizons
- CCS projects are complex and most organizations lack of familiarity with the full CCS chain, such that project implementation may require partnerships and complicated commercial agreements
- Policy uncertainty exists around climate change regulations and GHG reduction requirements at the federal level in Canada and in Alberta beyond 2014, when the SGER is expected to expire.

3.2 Permanence

In the proposed protocol, permanence will be addressed on a project-specific basis through the implementation of a complete measurement, monitoring and verification (MMV) plan, in accordance with regulatory requirements. In the protocol, the onus lies on the project developer to ensure the injection and storage of CO_2 in deep saline formations will result in permanent storage. The MMV program is designed to show that CO_2 has been stored permanently within the target formation.

The proposed protocol is not applicable to CO_2-enhanced hydrocarbon recovery and is only applicable to the injection of CO_2 into deep saline formations where hydrocarbon

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[5] http://www.energy.alberta.ca/Org/pdfs/CCS_Implementation.pdf

production is not possible. Therefore, there are no risks related to CO_2 recirculation within the formation or leakage from producing wells.

For the Quest CCS Project, an MMV Plan was required by the Terms of reference pursuant to the Canadian Environmental Assessment Act and the Alberta Environmental Protection and Enhancement Act, Environmental Assessment Regulation. The MMV plan was included in the full Environmental Assessment, submitted to the Governments of Canada and Alberta in November 2010. For further information refer to Appendix A of the Shell Quest CCS Project Environmental Assessment. The geological storage scheme is defined in detail in the Quest Carbon Capture and Storage Project Directive 65: Application for an Acid Gas Storage Scheme submitted to the Energy Resources Conservation Board (ERCB) in November 2010.

3.3 Risks to implementation/leakage

Risk assessment involves identifying pathways for the leakage of injected CO_2 from the reservoir. The data from the site characterization and reservoir modeling will help identify relevant risk pathways. The monitoring program should be tailored to monitor the identified risks. For example, most geological sites are in reservoirs with a well-defined cap rock and storage trap, so the most likely pathways for leakage are the injection wells themselves or the plugged abandoned wells from previous reservoir operations. In saline formations where oil and gas wells are found, faults and fractures that are present would also pose a potential risk for migration.

A corrective action plan would serve for those wells that are considered to be high risk for leakage (i.e., poor condition of cement, poor maintenance, and penetrating the injection reservoir and confining zones). The corrective action plan would involve either remediation or monitoring for leakage at the well. The ability to convert one or more of the wells to monitoring wells for the project may also be investigated.

Leakage is defined as the shifting of emissions to outside of the project boundary and has been addressed by identifying the sources, sinks and reservoirs (SSRs) of GHG emissions through a full lifecycle analysis. The proposed protocol accounts for all relevant upstream and downstream emission sources.

The main types of GHG leakage that could occur from CCS projects would be related to the emissions from the extraction and processing of fossil fuels upstream of the project activity, the indirect emissions associated with heat or electricity purchased from off-site, and the downstream emissions associated with long term monitoring of the storage site and site decommissioning. All of these potential forms of leakage have been identified as SSRs within the proposed protocol and have been quantified where relevant.

Physical leakage of CO_2 from the storage reservoir into other zones outside of the intended storage formation will be minimized through site selection, field development plan design and well design, as well as operational practices. The early detection of any leak, and follow up actions, will be enabled by the implementation of a detailed MMV plan, as discussed in the Permanence section, above. Should the MMV program identify leakage of CO_2 outside of the storage formation despite preventative measures, a site specific remedial plan will be implemented.

3.4 Impacts/co-benefits

The primary purpose of carbon capture and storage is to reduce GHG emissions to the atmosphere. The implementation of CCS to reduce emissions in Alberta is another example of the Government of Alberta's leadership in environmental management. The demonstration of CCS technologies at the scale proposed by the Shell Quest project will act as a model and enable other CCS projects world-wide. The Government of Alberta's leadership in the demonstration of these technologies may create future opportunities if these technologies are later exported to other parts of the world. CCS projects, including the Quest project itself will provide employment and contracting opportunities in Alberta.

3.5 Ownership

For consistency with other approved Alberta Offset System protocols, this quantification methodology also does not explicitly assign ownership. As such, it is the responsibility of the project proponent to provide proof of ownership of all emission reductions claimed at the time of third party verification or upon request by Alberta Environment (e.g. through contracts with other relevant participants involved in the CO_2 capture, transportation, injection and storage processes).

Where multiple proponents are involved in a project, each proponent would be required to provide documentation of the transfer of CO_2 from the point of capture through to the point of injection to ensure that emission reductions are only counted once, consistent with the Alberta Offset System guidelines. Given the large scale of CCS projects and the significant value of the offsets that can be generated from these projects, it is expected that proponents will establish the necessary commercial agreements as part of the normal course of business and should not have much difficulty providing documentation to demonstrate ownership of offsets.

3.6 Verification

Qualified, accredited third parties must be able to verify that the reductions or removals have been achieved as claimed. In order to support verification, the proposed protocol suggests that the following records be made available for verification purposes.

- Metered volumes of CO_2 captured and injected into the saline formation, measured at, or as close as practical to the injection wellheads
- Gas analyses reflecting the composition (% volume CO_2) of the injected gas stream
- Metered fossil fuel volumes consumed to operate the CCS Project
- Metered electricity and steam usage at the capture site
- Calibration and maintenance records for all meters
- Relevant permits for operating CCS facilities and proof of compliance with these permits
- Documentation and records of measurement, monitoring and verification (MMV) activities completed for the CCS project

4 Protocol Technical Scientific Foundation

The current status of technologies applicable for use under this proposed protocol is overviewed below.

Capture

Current and emerging capture application technologies are depicted in the table below for general reference.

Table 2: Current and Emerging Capture Application Technologies[6]

Capture Technologies	Capture Applications			
	Process Streams	Flue gas Separation	Oxy-fuel Combustion	Gasification
Solvents	Current – Chemical and physical solvents; Emerging – improved solvents, contacting equipment and process designs	Current – Chemical solvents; Emerging – improved solvents, contacting equipment and process designs	Emerging – Biomimetic solvents	Current – Chemical and physical solvents; Emerging – improved solvents, contacting equipment and process designs
Membranes	Current – Polymeric; Emerging – Ceramic, Facilitated transport, and Carbon Contactors			
Sorbents	Current – Zeolites and Activated carbon			
		Emerging – carbonates, and carbon-based sorbents	Emerging – Adsorbents for O_2/N_2 separation, Perovskites, and oxygen chemical looping	
Cryogenic Distillation	Current – Ryan Holmes process	Current – Liquefaction; Emerging – Hybrid processes	Current – Distillation; Emerging – Improved distillation	Current – Liquefaction; Emerging – Hybrid processes

The most industry proven and reliable capture technology are solvent based and likely to be of relevance for process gas separation of industrial process streams (hydrogen production) in Alberta. In this context, CO_2 capture infrastructure consists of the following main process blocks:

- CO_2 capture, potentially including amine absorbers and associated equipment.
- Amine regeneration unit(s), which may include the following:
    - The stripper column and associated reboiler, pumps and heat exchangers

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[6] API, IPIECA 2007

  - Amine filtration
  - Amine storage
  - The CO_2 vent stack (intermittent maintenance or emergency use only)
- CO_2 compression, which may include a multi-stage compressor with an electrical motor and interstage coolers and knockout drums
- CO_2 dehydration, which may include a triethylene glycol (TEG) absorber and regeneration unit

Specific to the Quest project, the amine absorbers will use a methyl diethanolamine-type (MDEA) solvent to capture the CO_2 from the synthetic gas off the SMRs. The custom MDEA-based solvent mixture is a licensed Shell amine system called ADIP-X that is selective for CO_2. The absorbed CO_2 will be separated from the amine using heat (steam) to regenerate the amine and produce CO_2 that is more than 95% pure, at slightly above atmospheric pressure. Steam will be sourced from an existing natural gas-fired cogeneration unit at the Scotford site.

The combined compressor and dehydration unit will pressurize and dry the CO_2 gas to approximately 14,500 kPa gauge. This will prepare the CO_2 stream for transportation by pipeline. The compressor will be driven by an electric motor using electricity from the grid or from a nearby gas-fired cogeneration unit. The dehydration unit will use steam for TEG regeneration.

The CO_2 capture infrastructure may contain a method for metering the CO_2 out of the system. Metering facilities at Quest will comprise a pressure-regulating valve and flow meters. CO_2 will be measured using mass flow or inferential orifice flow measurement. This meter will be used as an integral part of the leak detection on the CO_2 pipeline system. Quality sampling of the CO_2 stream will take place to verify that it meets minimum pipeline specifications. In general, metering of the captured CO_2 and subsequent subtraction of losses and fugitives uses an indirect calculation method. Measurement of injected CO_2 at the point of injection uses a direct calculation method. Both calculation methods require direct measurement. Direct calculation methods are preferred in general and used in this method as they tend to be more robust and accurate.

Transport

In general transport emissions are not difficult to quantify as all feasible forms of CO_2 transportation would use industry standard technologies (road, rail, pipeline) with quantifiable volumes of fuels directly associated to the activity. Where necessary, prorating multiple inlet and outlet streams of CO_2 transported through one mode is acceptable for quantification. Mixed mode transportation is acceptable and quantifiable.

For the Quest project, the CO_2 pipeline consists of a single high-vapour-pressure pipeline approximately 80 kilometers (km) long with an outside diameter of 12 inches that will transport dehydrated, compressed, dense-phase CO_2 from the Scotford Upgrader to the injection wells located in the storage field. The CO_2 will be distributed to the injection wells using smaller lateral pipelines, less than 15 km in length. The pipeline construction materials (steel, wall thickness 12.1mm, externally coated), line block valve spacing (approximately 15 km) and all other design parameters for the pipeline will adhere to the relevant design standards and industry codes (ie CSA Z662 or ANSI B31.4 as applicable). Other than the line block valves and monitoring equipment, no other facilities are associated with the CO_2 pipeline as supplemental compression is not required. A supervisory control and data acquisition (SCADA) system will collect and transmit data from the CO_2 pipeline back to the Scotford Upgrader control room and will centrally control and monitor the line break valves.

Storage in Deep Saline Geological Formations

There are several mechanisms which enable long term storage of CO_2 in geological formations.[6] Most geologic storage options, with the exception of adsorption, are most efficient at depths greater than 800 metres as the formation pressure and temperature causes CO_2 to remain in a dense state.[6] There are five general mechanisms which enable geologic storage:

1) Physical or volumetric trapping below an impermeable, confining layer (caprock). This includes man-made cavities where un-dissolved CO_2 can be trapped in pore spaces and prevented from seeping to the surface.
2) Capillary or residual trapping (retention in an immobile phase, trapped in the pore spaces of the storage formation);
3) Mineral trapping or mineralization (precipitation as a carbonate material);
4) Solubility trapping (dissolution of CO_2 in solution in the formation fluids that saturate the pore space within a rock formation
5) Adsorption onto organic matter in coal and shale (i.e. CO_2 bonds with formation rocks).

Geologic structural and stratigraphic traps have demonstrated the ability of reservoirs to seal and store hydrocarbon liquids and gases for millions of years. The structural and stratigraphic mechanisms that initially trapped these materials typically remain intact as fluids are extracted from or injected into these reservoirs, and continue to support the long-term storage of reservoir fluids.[6]

CO_2 can be injected into and stored in two main types of non-producing reservoirs: depleted oil and gas reservoirs and saline formations. This protocol is only applicable to storage in saline formations. The following provides a brief description of the characteristics of the specific geological formation in which CO_2 will be injected into and stored for the Quest Project. Other CCS projects may select saline formations with similar characteristics for CO_2 storage.

For the Quest CCS Project, CO_2 will be injected at a depth of approximately two kilometers below the surface into the Basal Cambrian Sands (BCS) geological formation via 3 to 8 injection wells. The CO_2 will be contained within the BCS formation by a combination of three regionally extensive layers of impermeable and continuous cap rock. These layers will keep CO_2 isolated within the formation and will prevent any upward migration.

Injected CO_2 initially displaces brine in the reservoir and then dissolves in the brine. A portion of the CO_2 is permanently trapped in place due to residual trapping, solubility trapping and mineral trapping. The free-phase CO_2 is the remaining CO_2 trapped by structural and stratigraphic trapping in the BCS storage complex.

There are no known hydrocarbons or hydrocarbon pools in the BCS formation within the area of interest for the Shell Quest project. Since there are no hydrocarbon production activities currently, or expected in the future, within the storage complex, there will not be any recycling of CO_2 from producing wells. Therefore, there are no risks related to CO_2 recirculation within the formation or leakage from producing wells.

5 Protocol Operational Framework

The proposed protocol will result in real, quantifiable and verifiable reductions through direct measurement of the quantity of CO_2 captured and injected into a deep saline geological formation for permanent storage.

The quantification approach used in the protocol is based on the direct measurement of the quantity of CO_2 that has been captured from the industrial process and injected into the geological formation. The baseline emissions are quantified from the metered quantity of CO_2 in the project that is captured and injected into the deep geological formation for permanent storage that would normally have been emitted to the atmosphere. The incremental GHG emissions resulting from the energy inputs required to capture, compress, transport, inject and store CO_2 are aggregated to represent the project emissions, such that these incremental emissions can be deducted from the injected volume to determine the net GHG reduction at the project level.

The quantification of the reductions, removals and reversals of relevant SSRs for each of the greenhouse gases will be completed using the methodologies outlined in Table 6 and Table 9 below. These calculation methodologies serve to complete the following four equations for calculating the emission reductions from the comparison of the baseline and project conditions.

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

$$\text{Emissions}_{\text{Baseline}} = \text{Emissions}_{\text{Industrial Process Emissions at Hydrogen Production Facility}}$$

$$\text{Emissions}_{\text{Project}} = \text{Emissions}_{\text{Fuel Extraction and Processing}} + \text{Emissions}_{\text{Electricity Consumption}} + \text{Emissions}_{\text{Off-Site Heat and Power Co-Generation}} + \text{Emissions}_{\text{On-Site Heat and Power Co-Generation}} + \text{Emissions}_{\text{Inspection and Maintenance}} + \text{Emissions}_{\text{Fugitive Emissions from the Geological Storage Formation}}$$

$$\text{Total } CO_{2\,\text{Equivalent}} \text{ Emissions} = \sum (CO_2 \text{ emissions}) + \sum (CH_4 \text{ emissions}) * GWP_{CH4} + \sum (N_2O \text{ emissions}) * GWP_{N2O}$$

Where:

Emissions $_{\text{Baseline}}$ = sum of the emissions under the baseline condition.

- Emissions $_{\text{Industrial process emissions at Hydrogen Production Facility}}$ = emissions under SS B1 Industrial process emissions at Hydrogen Production Facility

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

- Emissions $_{\text{Fuel Extraction and Processing}}$ = emissions under SSs P5 and P6 Extraction/ Processing and Transportation of Fuels Used On/ Off-Site for Heat and Power Generation
- Emissions $_{\text{Electricity Consumption}}$ = emissions under SS P8 Generation of Electricity for Use by CCS Facilities
- Emissions $_{\text{Off-Site Heat and Power Generation}}$ = emissions under SS P9 Off-Site Heat and Power Co-Generation
- Emissions $_{\text{On-Site Heat and Power Generation}}$ = emissions under SS P10 On-Site Heat and Power Co-Generation
- Emissions $_{\text{Inspection and Maintenance}}$ = emissions under SS P11 Inspection and Maintenance of CCS Facilities
- Emissions $_{\text{Fugitive Emissions from the Geological Storage Formation}}$ = emissions under SS P20 Fugitive Emissions from the Geological Storage Formation

$CO_{2\ \text{Equivalent}}$ Emissions = sum of all GHG emissions converted to CO_2 equivalent terms

- GWP $_{CH4}$ = The Global Warming Potential of Methane is 21
- GWP $_{N2O}$ = The Global Warming Potential of Nitrous Oxide is 310

5.1 Baseline Condition

5.1.1 Assessment of Baseline Scenarios

In order to assess potential baseline scenarios for the project activity, an assessment of possible baseline scenarios was conducted based on recommended best practice guidance contained in the Alberta Offset Credit Project Guidance Document. Table 3, below, provides a summary of the baselines considered.

Table 3: Assessment of Possible Baseline Scenarios

1. Baseline Options	2. Description	3. Static/ Dynamic	4. Accept or Reject and Justify
Historic Benchmark	Assessment of the baseline emissions of pre-project facility operations over a historic period as proxy for future anticipated activity. The conventional approach would be to utilize three years of activity data (facility emissions per unit of output) to develop a project specific baseline before the implementation of the project.	Static.	**Reject**. The facility may increase or decrease throughput in the future, depending on supply, demand, and other market factors. As a result, the production of H_2 will vary. A static baseline cannot accurately estimate the fluctuating nature of future emissions.
Performance Standard	Assessment of the typical emission profile of facilities which operate steam methane reformers in Alberta. Average emissions, corrected for the amount of H_2 produced, would form the performance standard.	Dynamic or Static.	**Reject**. A performance standard would likely not be accurate considering the variability in the efficiency and design of operations.
Projection-Based	Assessment of the facility emissions profile based on the mass of CO_2 sequestered in the project condition.	Dynamic.	**Accept.** The mass of CO_2 captured and injected can be accurately metered. This dynamic baseline will account for the project-specific nature of the facility emissions profile.
Comparison-based	Assessment of the baseline GHG emissions based on the comparison of the project facility to the performance of a control facility operating without carbon capture and storage.	Dynamic	**Reject**. The unique design of CCS projects, in addition to variable throughput, would make a comparison-based baseline inaccurate.
Adjusted Baseline	Assessment of the baseline GHG emissions from facilities using an adjustment factor to account for the extent to which Alberta facilities already capture and store CO_2.	Dynamic.	**Reject.** This baseline is not applicable. The current market uptake of CCS technologies is negligible so no adjustment would be needed to account for business as usual conditions.

5.1.2 Selection and Justification of Baseline Scenario

Several criteria were used to evaluate each baseline scenario, such as data availability, environmental integrity, accuracy, transparency, reliability and consistency with the Alberta Offset System requirements and ease of application. The projection-based baseline was selected as the best approach to quantify the baseline emissions from emitting an equivalent amount of CO_2 as that which was captured and stored in the projection condition. The baseline condition is dynamic in approach as the quantity of CO_2 captured and injected will vary from year to year based on external factors such as the on-stream availability of the steam methane reformers and hydrogen requirements for the bitumen upgrading processes.

In summary, the baseline scenario for the protocol is the continued practice of venting CO_2 to the atmosphere from industrial process emission vent stacks. The baseline emissions are quantified from the metered quantity of CO_2 that is captured and injected into the deep saline geological formation for permanent storage that would normally have been vented to the atmosphere. This type of baseline is commonly referred to as a projection-based baseline. The use of direct measurement to represent the baseline provides a high level of accuracy.

5.1.3 Additionality

Since the reduction of industrial process emissions is not currently regulated or legislated by law, any steps taken to reduce industrial process emissions through the implementation of carbon capture and storage technology would be additional to regulation. Since there are other lower cost options which meet regulatory requirements to serve as an acceptable baseline, the project is additional. For a general review of the requirement of additionality, refer to Section 2.3.

5.1.4 Identification of Baseline Sources and Sinks

Sources, sinks, and reservoirs of emissions for an activity are assessed based on Guidance from ISO 14064-2, Alberta Environment and Environment Canada and are classified as follows:

Controlled:	The behaviour or operation of a controlled source and sink is under the direction and influence of a Project Developer through financial, policy, management, or other instruments.
Related:	A related source and sink has material and/or energy flows into, out of, or within a project but is not under the reasonable control of the project developer.
Affected:	An affected source and sink is influenced by the project activity through changes in market demand or supply for projects or services associated with the project.

Figure 1: Process Flow Diagram for the Project Baseline

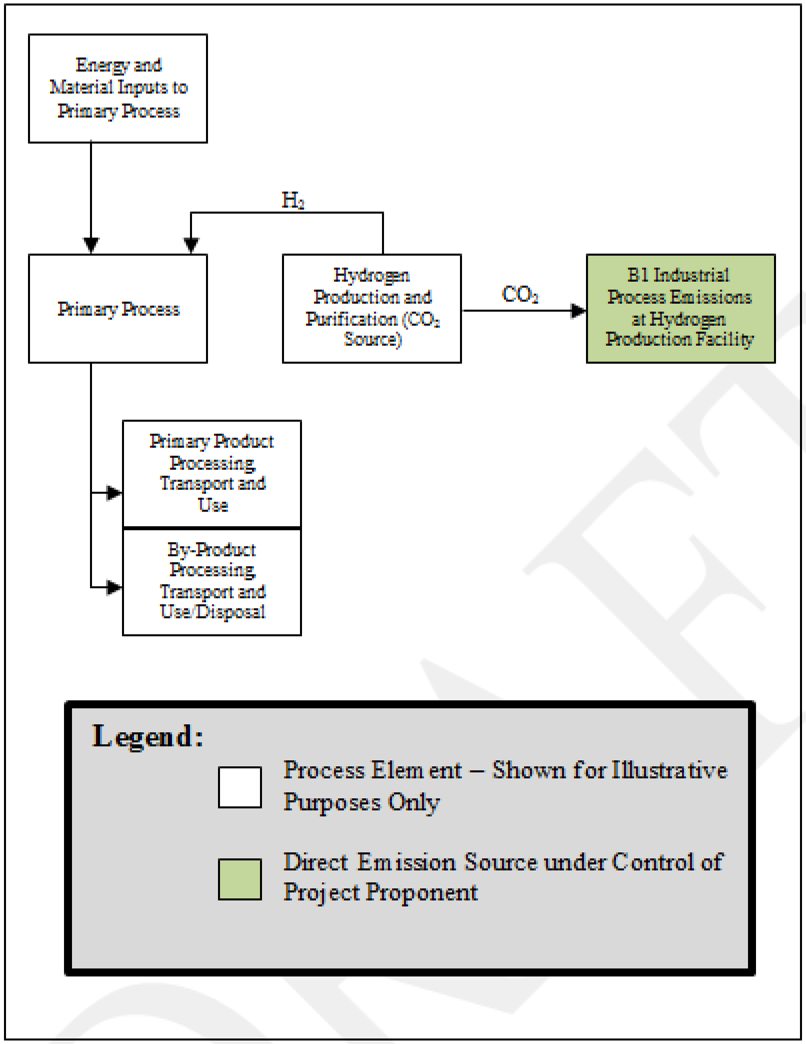

Table 4: Process Elements Description

Process Element	Description
Energy and Material Inputs to Primary Process	The primary process (e.g. bitumen upgrading) will require energy inputs such as electricity, heat, and fossil fuels which may be supplied from on- or off-site sources. Material inputs are required to produce the primary product. The primary input to the primary process is raw bitumen, which is upgraded into synthetic crude oil. Natural gas is also a major input for hydrogen production. The quantity of energy consumed should be tracked in kWh or kJ and material inputs in kg or m^3.
Primary Process	The primary process is the sum of the activities that are undertaken to produce the primary product sold by the facility. The primary process under this protocol is bitumen upgrading to produce synthetic crude oil. The primary process does not include the hydrogen production processes.
Hydrogen Production and Purification (CO_2 Source)	Methane exposed to steam in the presence of a catalyst will react to form H_2, CO_2, and other carbon oxides. The steam methane reforming process refers to the creation and separation of H_2 from the other gases. This may involve the operation of steam methane reformers, CO shift reactors, and pressure swing adsorption units. The waste CO_2 stream (and trace amounts of contaminant gases such as CH_4) are separated in this process.
Primary Product Transport, Processing, and Use	The primary product, synthetic crude oil in this case, will need to be transported to its end-use location by pipeline, rail, ship, or truck. The synthetic crude oil will also need to be refined to produce gasoline, diesel and other hydrocarbon products, likely at a downstream refining facility. These activities result in GHG emissions from fossil fuel combustion. The use of the primary product may result in additional GHG emissions.
By-Product Processing, Transport, and Use/Disposal	By-products from the primary production process may include petroleum coke, sulphur or other products. These by-products may be processed further for marketing, distribution and use or may be disposed of.

Figure 2: Baseline SSRs for CCS Projects

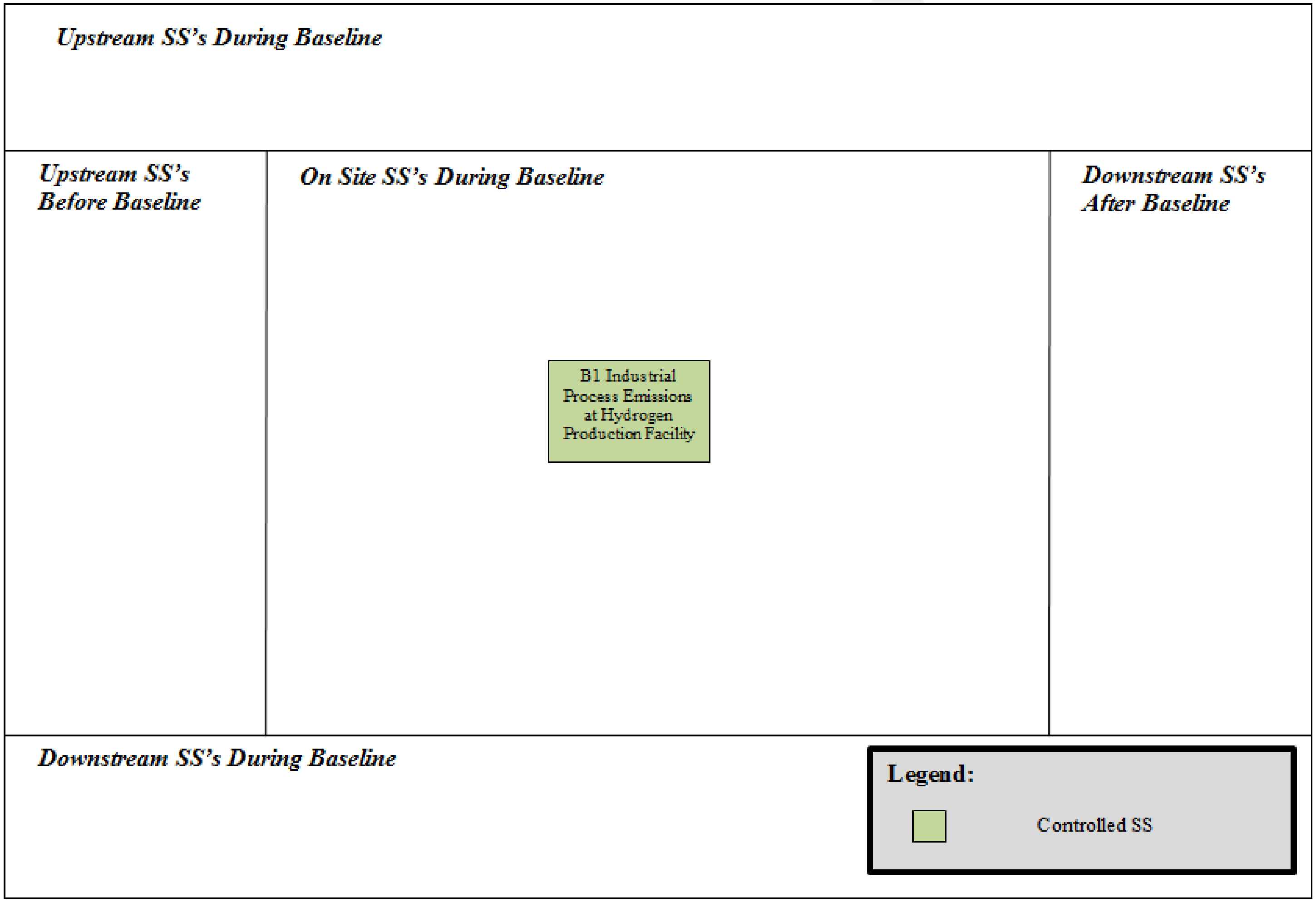

Table 5: Baseline Condition SSRs

SS	Description	Controlled, Affected, Related
Upstream SSs Before Project		
	N/A	
Upstream SSs During Project		
	N/A	
On-Site SSs During Project		
B1 Industrial process emissions at Hydrogen Production Facility	All industrial process emissions of the H_2 production process (e.g. steam methane reforming process) are emitted to the atmosphere. The emitted gas stream is expected to be primarily composed of carbon dioxide, with hydrogen and trace amounts of carbon monoxide and hydrocarbons.	Controlled
Downstream SSs During Project		
	N/A	
Downstream SSs After Project		
	N/A	

5.1.5 Baseline Determination/Quantification

The projection-based baseline emissions are the sum of the emissions under SSR B1 Industrial Process Emissions at Hydrogen Production Facility and Table 6 provides the quantification calculations:

Table 6: Quantification Procedures for Project Baseline

1.0 Project/ Baseline SS	2. Parameter / Variable	3. Units	4. Measured / Estimated	5. Method	6. Frequency	7. Justify measurement or estimation and frequency
Baseline SSs						
B1 Industrial process emissions at Hydrogen Production Facility	$\textbf{Emissions}_{\text{IPE at Hydrogen Production Facility}} = \textbf{Emissions}_{\text{Storage in Saline Geological Formation}}$ **Where,** $\textbf{Emissions}_{\text{Storage in Saline Geological Formation}} = \sum(\text{Vol. Gas Injected} * \%_{CO2} * \rho_{CO2}); \sum(\text{Vol. Gas Injected} * \%_{CH4} * \rho_{CH4}); \sum(\text{Vol. Gas Injected} * \%_{N2O} * \rho_{N2O})$					
	Emissions $_{\text{IPE at Hydrogen Production Facility}}$	kg of CO_2	N/A	The calculation of baseline emissions at the hydrogen production facility relies on data collected during the project condition and does not consider those emission sources that are not impacted by the implementation of the CO_2 capture equipment (e.g. those emissions that are functionally equivalent). The only quantified emission source in the baseline is related to the quantity of CO_2 that is being captured in the project condition.	N/A	Quantity being calculated. Note that this value refers to the baseline quantity of CO_2 that would have been emitted to the atmosphere in the absence of the CCS project
	Emissions $_{\text{Storage in Saline Geological Formation}}$	kg of CO_2e	N/A	This value refers to the metered quantity of CO_2 sequestered (removed) in saline geological formation in the project condition.	N/A	Direct metering is standard practice. Frequency of metering is highest level possible.

	Volume of Gas Injected into Saline Geological Formation / Vol. $_{\text{Gas Injected}}$	m^3	Measured	Direct metering of volume of gas injected into the saline geological formation in the project condition, measured directly at each injection well.	Continuous metering	Direct metering is standard practice. Frequency of metering is highest level possible.
	CO_2 Concentration in Injected Gas / % CO_2	% Volume	Measured	Direct measurement of the composition prior to input into the pipeline and prior to injection at the well head.	Daily	Composition should be consistent at the point of input into the pipeline as prior gas processing steps would be closely controlled. Any changes in composition would be detected at upstream processes.
	Density of CO_2 / ρ_{CO2}	kg/m^3	Estimated	Constant value for conditions at which volumetric meter reports volume (1.87 kg/m^3 at 15°C and 1 atmosphere, the reference conditions commonly used by the oil and gas industry in North America)	N/A	Reference value. If the flow meters used in the project condition measure the volume of gas at other temperatures and pressures then these conditions should be corrected to a single set of reference conditions.
	Volume of Gas Injected into Saline Geological Formation / Vol. $_{\text{Gas Injected}}$	m^3	Measured	Direct metering of volume of gas injected into the saline geological formation in the project condition, measured directly at each injection well.	Continuous metering	Direct metering is standard practice. Frequency of metering is highest level possible.
	CH4 Concentration in Injected Gas / % CH_4	% Volume	Measured	Direct measurement of the composition prior to input into the pipeline and prior to injection at the well head.	Daily	Composition should be consistent at the point of injection as prior gas processing steps would be closely controlled. Any changes in composition would be detected at upstream processes.

	Density of CH_4 / ρ_{CH4}	kg/m^3	Estimated	Constant value for conditions at which volumetric meter reports volume (0.677kg/m³ at 15°C and 1 atmosphere, the reference conditions commonly used by the oil and gas industry in North America)	N/A	Reference value. If the flow meters used in the project condition measure the volume of gas at other temperatures and pressures then these conditions should be corrected to a single set of reference conditions.
	N2O Concentration in Injected Gas / % N_2O	% Volume	Measured	Direct measurement of the composition prior to input into the pipeline and prior to injection at the well head.	Daily	Composition should be consistent at the point of injection as prior gas processing steps would be closely controlled. Any changes in composition would be detected at upstream processes.
	Density of N_2O / ρ_{N2O}	kg/m^3	Estimated	Constant value for conditions at which volumetric meter reports volume (1.84kg/m³ at 15°C and 1 atmosphere, the reference conditions commonly used by the oil and gas industry in North America)	N/A	Reference value. If the flow meters used in the project condition measure the volume of gas at other temperatures and pressures then these conditions should be corrected to a single set of reference conditions.

5.1.6 Risk Assurance Factors

Risk assurance factors are not applicable to this protocol. They are typically used as an assurance against reversals which are based on the probability of biological or agricultural sequestration projects to undergo reversal. No precedent is available for projects which would fall under this protocol, and hence a risk assurance factor would not improve the overall accuracy for estimates of project emission reductions. Permanence and the possibility of reversal for projects under this protocol is accounted for in the MMV plan.

5.2 Project Condition

5.2.1 Project Scope

CCS project activities consist of three distinct components, namely the capture and compression of CO_2, the transport of CO_2 to the injection wells, and the storage of CO_2 in a geological formation.

The main process elements of a typical CCS Project have been described above, in Section 4. Other CCS projects may employ other CO_2 capture, transport and storage technologies and processes and are not precluded from applying this protocol provided that the CO_2 is captured from a source of industrial process emissions and the storage reservoir is a non-hydrocarbon producing permanent storage formation.

5.2.2 Definitions of Practices

As described in Section 4, there are three main steps to the practices in the project condition for projects under this protocol. Specifically for the Shell Quest project, the practices and are depicted as the "Process Elements – for illustrative purposes only" blocks in Figure 3 and corresponding descriptions are given below.

1. Primary Process – This is an industrial process which requires a concentrated stream of hydrogen for cracking hydrocarbons.

2. Hydrogen production – This necessitates the release of CO_2 (main CO_2 source from which sequestered carbon will be captured).

3. CO_2 Capture and Processing– The separation of CO_2 from industrial process waste gases into a concentrated stream. Various technologies may be employed however typically an amine solvent is cycled through various temperatures to absorb and then remit CO_2 from the waste stream to concentrated streams respectively. Further purification, dehydration, and removal of contaminants would constitute processing to prepare the CO_2 stream for compression and transport.

4. CO_2 Compression and Dehydration – Before transportation, CO_2 is compressed and dehydrated.

5. Transportation of CO_2 – The displacement of CO_2 from the capture site to the injection site through a network of pipelines. Transfer of ownership may be applicable here for projects where the capture and injection equipment is owned by different parties.

6. CO_2 Injection - The receipt of CO_2 from the transportation network to the injection site, may include measurement and condensate knock-out.
7. CO_2 Storage – After injection, the long term storage of dense phase CO_2 in deep saline formations.

5.2.3 Identification of Project Sources and Sinks

Sources, sinks and reservoirs for the project condition were identified based on review of existing best practice guidance contained in relevant GHG quantification protocols and CCS project configurations. This process confirmed that SSRs in the process flow diagram (Figure 3) covered the full scope of eligible project activities under this protocol.

These SSRs have been further refined according to the lifecycle categories identified in Figure 4. These SSRs were further classified as controlled, related, or affected as described in Table 8 below.

Project and baseline SSRs that are excluded from analysis are compared in Section 5.2.6.

Figure 3: Process Flow Diagram for the Project Condition

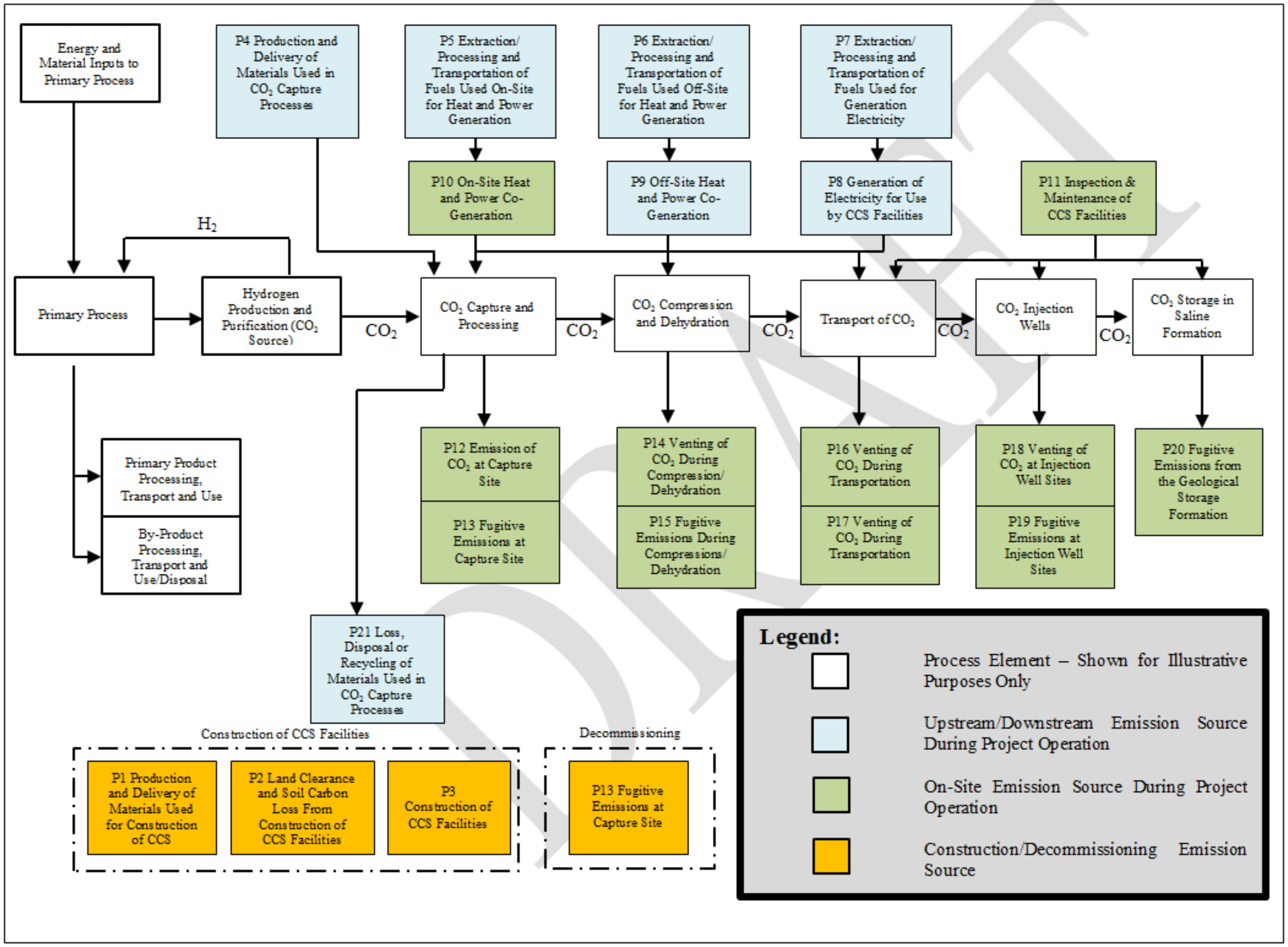

Table 7: Process Element Descriptions

Process Element	Description
Energy and Material Inputs to Primary Process	The primary process will require energy inputs such as electricity, heat, and fossil fuels which may be supplied from on or off-site sources. Material inputs are required to produce the primary product. For a bitumen upgrading facility, bitumen will be the primary material input to the upgrading process, in addition to natural gas for hydrogen production. The quantity of energy consumed should be tracked in kWh, kJ, or m^3 and material inputs in kg or m^3.
Primary Process	The primary process is the sum of the activities that are undertaken to produce the primary product sold by the facility. In this protocol the primary process is the hydrogen-consuming process (e.g. bitumen upgrading to produce synthetic crude oil). The primary process does not include the hydrogen production and purification processes.
Primary Product Transport, Processing, and Use	The primary product will need to be transported to its end-use location by pipeline, rail, ship, or truck. In the case of products like synthetic crude oil, additional processing may be required. These activities result in GHG emissions from fossil fuel combustion. The use of the primary product may result in additional GHG emissions.
By-Product Processing, Transport, and Use/Disposal	By-products from the primary production process may include petroleum coke, sulphur or other products. These by-products may be processed further for marketing, distribution and use or may be disposed of.
Hydrogen Production and Purification (CO_2 Source)	This SSR includes all activities undertaken to produce and purify hydrogen for use in the primary process. The most common method of hydrogen production is steam methane reforming. In this process, methane exposed to steam in the presence of a catalyst will react to form H_2, CO_2, and other carbon oxides. The operation of steam methane reforming equipment and hydrogen separation equipment (steam methane reformers, CO shift reactors, and pressure swing adsorption units) are included in this process.
CO_2 Capture and Processing	CO_2 will need to be separated from the gaseous byproducts of the hydrogen production and purification system. This may require a range of chemical and physical processes. The source and quantity of any material, heat, or electricity inputs to the CO_2 capture process should be tracked.
CO_2 Compression and Dehydration	Before transportation, the CO_2 will need to be compressed. In addition, dehydration may be required to prevent hydrate formation. This may be achieved through heating or other processes. The volume and quantity of fossil fuels and/or the quantity of electricity consumed should be tracked for the compressor(s) and dehydration unit(s).
Transport of CO_2	CO_2 will be transported via pipeline to the injection site. Depending on the length of the pipeline, additional compression may be needed. The volume and quantity of fossil fuels and/or the quantity of electricity consumed should be tracked for any additional compression.
CO_2 Injection Wells	CO_2 will be injected deep underground into the saline formation, often to depths greater than one thousand meters. In certain cases, additional energy inputs may be required to at the injection wells for the injection operation or to operate monitoring equipment. The volume and quantity of fossil fuels and/or the quantity of electricity consumed should be tracked.
CO_2 Storage in Saline Formation	CO_2 will be injected into and stored in a saline geological formation. The saline formation will be situated below layers of impermeable, continuous and thick cap rock.

Figure 4: Project Condition SSRs

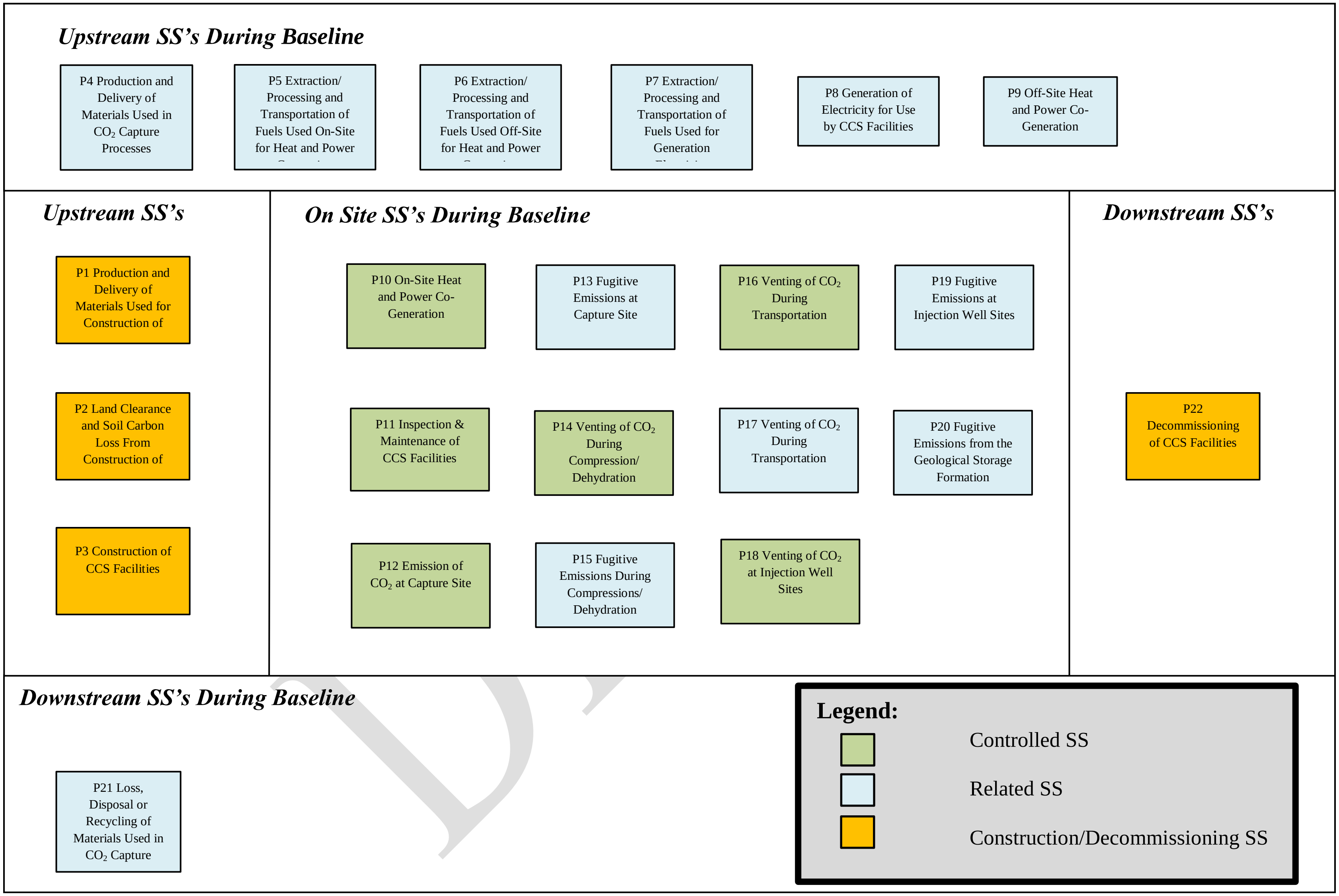

Table 8: Project Condition SSRs

SSR	Description	Controlled, Affected, Related
Upstream SSRs Before Project		
P1 Production and Delivery of Materials Used for Construction of CCS Facilities	Materials used in the construction of CCS 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
P2 Land Clearance and Soil Carbon Loss from Construction of CCS 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. The carbon content of all soil types and area cleared for construction are important characteristics to be tracked.	Related
P3 Construction of CCS Facilities	The process of construction at the site will require a variety of heavy equipment, smaller power tools, cranes and generators. The operation of this equipment will have associated greenhouse gas emission from the use of fossil fuels and electricity.	Related
Upstream SSRs 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. GHG emissions are attributed to the fossil fuel consumption for transport of these materials and electricity and fossil fuel inputs for their production. The total aggregate quantity of each chemical delivered to the site should be tracked.	Related
P5 Extraction/Processing and Transportation of Fuels Used On-Site for Heat and Power Generation	The fuels used for heat and power 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 are important processes to be tracked.	Related
P6 Extraction/Processing and Transportation of Fuels Used Off-Site for Heat and Power Generation	The fuels used for heat and power 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 are important processes to be tracked.	Related
P7 Extraction/Processing and Transportation of Fuels Used for Generation of Grid Electricity	The fuels used for the generation of grid electricity will need to 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 grid electricity used to operate the CCS facilities should be tracked.	Related
P8 Generation of Electricity for	The generation of electricity in Alberta is achieved with a mixture of energy sources.	Related

Use by CCS Facilities	Most of the electricity generation in Alberta is from coal-fired and natural gas-fired generating stations, with lesser contributions from hydro, wind, biomass and waste heat recovery power generating facilities. The quantity of electricity should be tracked to estimate related GHG emissions from grid electricity usage to operate the CCS facilities (e.g. electrically-driven compressors would be major electricity users). The project proponent will need to delineate all new electric equipment used to capture, transport and inject and store CO_2.	
P9 Off-Site Heat and Power Generation	Heat and electricity inputs may be required for CO_2 Capture and Processing, compression, dehydration, and transport. Heat and electricity may be generated independently or may be generated at third party cogeneration facilities. Important quantities to be tracked are the quantity and type of fossil fuels consumed to generate heat and electrical power and the quantity of electricity consumed.	Related
On-Site SSRs During Project		
P10 On-Site Heat and Power Generation	Heat or electricity inputs may be required for CO_2 Capture and Processing, compression, dehydration, and transport. Heat and electricity may be generated independently or may be generated at an on-site cogeneration unit. Important quantities to be tracked are the quantity and type of fossil fuels consumed to generate heat and electrical power and the quantity of consumed.	Controlled
P11 Inspection and Maintenance of CCS Facilities	The CO_2 pipeline and injection well will need to be inspected and monitored for leaks on a regular basis. The geological formation must also be monitored and tested regularly for signs of CO_2 leakage or migration. GHG emissions will result from fossil fuels or electricity consumed for maintenance activities for leak prevention or repair.	Controlled
P12 Emission of CO_2 at Capture Site	In the project condition, some CO_2 will be emitted from the hydrogen production units as it will not be possible to achieve 100% capture efficiency. Venting of CO_2 may also be necessary for equipment maintenance or emergency shutdowns. Instances of venting should be logged and the duration of the venting event and the estimated volume of CO_2 vented should be recorded.	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 damaged equipment. It is expected that the gas will be primarily composed of H_2 and CO_2. GHG emissions are attributed the release of CO_2 to the atmosphere.	Related
P14 Venting of CO_2 During Compression/Dehydration	Emergency or planned vents of CO_2 may be necessary for compressor/dehydrator maintenance or emergency shutdowns. Instances of venting should be logged and the duration of the venting event and the estimated volume of CO_2 vented should be recorded.	Controlled

P15 Fugitive Emissions During Compression/ Dehydration	Unintended leaks of gas from the compressor and/or dehydrator may occur through faulty seals, loose fittings, damaged equipment, or worn down compressor packing. It is expected that the gas will be composed of CO_2 with trace amounts of other gases. GHG emissions are attributed the release of CO_2 to the atmosphere.	Related
P16 Venting of CO_2 During Transportation	Emergency or planned vents of CO_2 may be necessary for pipeline maintenance or shutdowns. Instances of venting should be logged and the duration of the venting event and the estimated volume of CO_2 vented should be recorded.	Controlled
P17 Fugitive Emissions During Transportation	Unintended leaks of gas from the CO_2 pipeline/transportation equipment and additional compressors may occur through faulty seals, loose fittings, damaged equipment, or worn down compressor packing. It is expected that the gas will be composed of CO_2 with trace amounts of other gases. GHG emissions are attributed the release of CO_2 to the atmosphere.	Related
P18 Venting of CO_2 at Injection Well Sites	Emergency or planned vents of CO_2 may be necessary for injection well workovers, mechanical integrity checks and maintenance. Instances of venting should be logged and the duration of the venting event and the estimated volume of CO_2 vented should be recorded.	Controlled
P19 Fugitive Emissions at Injection Well Sites	Unintended leaks of gas at the CO_2 injection well sites unit may occur through faulty seals or damaged equipment. It is expected that the gas will be composed of CO_2 with trace amounts of other gases. GHG emissions are attributed the release of CO_2 to the atmosphere.	Related
P20 Fugitive Emissions from the Geological Storage Formation	Abrupt leakage sources include injection well failure or leakage up a poorly sealed abandoned well[7]. Gradual leakage may occur by way of gas migration through undetected faults, fractures and/or wells. According to the IPCC, however, the risk of this type of leakage can be mitigated by appropriate site selection and system design and the implementation of an early monitoring and detection program.	Related
Downstream SSRs During Project		
P21 Loss, Disposal, or Recycling of Materials Used in CO_2 Capture Processes	Material inputs will need to be disposed or recycled at the end of their useful life. GHG emissions are attributed to the transport of materials to landfill or the processes by which the material is recycled. This SSR also accounts for GHG emissions associated loss of material during project operation.	Related
Downstream SSRs After Project		
P22 Decommissioning CCS of Facilities	Once the CCS facilities are no longer operational, the infrastructure may need to be decommissioned. This may involve the disassembly of the equipment, demolition of on-	Related

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[7] IPCC. (2005). IPCC Special Report on Carbon Dioxide Capture and Storage. Cambridge University Press: Canada.

	site structures, disposal of some materials, environmental restoration, re-grading, planting or seeding, and transportation of materials off-site. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to decommission the facilities.	

5.2.4 Project Determination/Quantification

The relevant project SSRs are quantified based on the calculations outlined in Table 9, below.

Table 9: Quantification Procedures for Project Condition

1.0 Project/ Baseline SS	2. Parameter / Variable	3. Units	4. Measured / Estimated	5. Method	6. Frequency	7. Justify measurement or estimation and frequency
Project SSRs						
P5 & P6 Extraction/ Processing and Transportation of Fuels Used Used On/Off-Site for Heat and Power Generation	**Emissions $_{\text{Fuel Extraction and Processing}}$ = ∑ (Vol. Fuel $_i$ * EF Fuel $_{i\ CO2}$); ∑ (Vol. Fuel $_i$ * EF Fuel $_{i\ CH4}$) ; ∑ (Vol. Fuel $_i$ * EF Fuel $_{i\ N2O}$)**					
	Emissions $_{\text{Fuel Extraction and Processing}}$	kg of CO_2 ;kg CH_4 ; kg N_2O	N/A	N/A	N/A	Quantity being calculated in aggregate based on quantity of fossil fuels used at each component of the CCS operations.
	Total Volume of Fossil Fuels Consumed to Operate CCS Facilities / Vol. Fuel $_i$	L/ m^3/ Other	Measured	Direct measurement of the volume of fossil fuels consumed at each component of the CCS project.	Continuous metering.	Quantity being calculated in aggregate based on quantity of fossil fuels used at each component of the CCS operations.
	CO_2 Emissions Factor for Extraction and Processing of Each Type of Fuel / EF Fuel $_{i\ CO2}$	kg CO_2 per L / m^3 / other	Estimated	From CAPP reference documents. Refer to Appendix B	Annual	Reference values represent best available emission factors for fuel extraction and processing.
	CH_4 Emissions Factor for Extraction and Processing of Each Type of Fuel / EF Fuel $_{i\ CH4}$	kg CH_4 per L / m^3 / other	Estimated	From CAPP reference documents. Refer to Appendix B	Annual	Reference values represent best available emission factors for fuel extraction and processing.
	N_2O Emissions Factor for Extraction and Processing of Each Type of Fuel / EF Fuel $_{i\ N2O}$	kg N_2O per L / m^3 / other	Estimated	From CAPP reference documents. Refer to Appendix B	Annual	Reference values represent best available emission factors for fuel extraction and processing.

P8 Generation of Electricity for Use by CCS Facilities	$\textbf{Emissions}_{\text{Electricity Consumption}} = \sum \textbf{Electricity}_{\text{Grid}} * \textbf{EF}_{\text{Grid CO2e}} + \sum \textbf{Electricity}_{\text{Ded. Off-Site}} * \textbf{EF}_{\text{Ded. Off-Site CO2e}}$					
	$\text{Emissions}_{\text{Electricity Consumption}}$	kg CO_{2e};	N/A	N/A	N/A	Quantity being calculated in aggregate based on quantity of grid electricity used at each component of the CCS operations.
	Incremental Grid Electricity Consumption for CCS Project / Electricity	kWh	Measured	Direct measurement of grid electricity consumption at each facility involved in the capture, compression, transport, injection, and storage of CO_2 less the total electricity contracted from specific source facilities. The total electricity consumption should be calculated as the sum of electricity consumption across individual components of the CCS project. Where individual metering is not present or disaggregation of CCS-related electricity consumption is not possible, the maximum rated kW capacity or maximum design loading of the relevant equipment may be used with a conservative estimate of equipment operating hours to estimate the electricity consumption. The total electricity contracted from specific source facilities should be calculated as per the guidance below. Excludes co-generation.	Continuous metering	Continuous direct metering represents the industry practice and the highest level of detail.
	Grid Emission Intensity Factor for Electricity Generation / $EF_{\text{Grid CO2e}}$	kg CO_{2e} / kWh	Estimated	Obtained from Alberta Environment offset project guidance documents.	Annual	Reference value adjusted periodically by Alberta Environment.

	Incremental Dedicated Off-Site Electricity Consumption for CCS Project / Electricity	kWh	Measured	Direct measurement of dedicated off-site electricity consumption at each facility involved in the capture, compression, transport, injection, and storage of CO_2 less the total electricity contracted from specific source facilities. The total electricity consumption should be calculated as the sum of electricity consumption across individual components of the CCS project. Where individual metering is not present or disaggregation of CCS-related electricity consumption is not possible, the maximum rated kW capacity or maximum design loading of the relevant equipment may be used with a conservative estimate of equipment operating hours to estimate the electricity consumption. The total electricity contracted from specific source facilities should be calculated as per the guidance below.	Continuous metering	Continuous direct metering represents the industry practice and the highest level of detail.
	Dedicated Off-Site Emission Intensity Factor for Electricity Generation / $EF_{Grid\ CO2e}$	kg CO_{2e} / kWh	Estimated	Estimated based on emission intensity of the off-site electricity generation facility operation	Annual	Reference value adjusted periodically.
	Incremental Dedicated On-Site Electricity Consumption for CCS Project / Electricity	kWh	Measured	Direct measurement of dedicated on-site electricity consumption at each facility involved in the capture, compression, transport, injection, and storage of CO_2 less the total electricity contracted from specific source facilities. The total electricity consumption should be calculated as the sum of electricity consumption across individual components of the CCS project.	Continuous metering	Continuous direct metering represents the industry practice and the highest level of detail.

				Where individual metering is not present or disaggregation of CCS-related electricity consumption is not possible, the maximum rated kW capacity or maximum design loading of the relevant equipment may be used with a conservative estimate of equipment operating hours to estimate the electricity consumption. The total electricity contracted from specific source facilities should be calculated as per the guidance below.		
	Dedicated On-Site Emission Intensity Factor for Electricity Generation / $EF_{Grid\ CO2e}$	kg CO_{2e} / kWh	Estimated	Estimated based on emission intensity of the on-site electricity generation facility operation	Annual	Reference value adjusted periodically.
P9 Off-Site Heat and Power Co-Generation	**$\text{Emissions}_{\text{Off-Site Heat and Power Co-Generation}} = \sum (\text{Vol. Fuel}_{CCS} * \text{EF Fuel}_{CO2})$; $\sum (\text{Vol. Fuel}_{CCS} * \text{EF Fuel}_{CH4})$; $\sum (\text{Vol. Fuel}_{CCS} * \text{EF Fuel}_{N2O})$** Where, **1) $\text{Vol. Fuel}_{CCS} = \text{Vol. Fuel}_{\text{Heat CCS}} + \text{Vol. Fuel}_{\text{Elec CCS}}$** **2) $\text{Vol. Fuel}_{\text{Heat CCS}} = (\text{Heat}_{CCS} / \text{Heat}_{Total}) * \text{Vol. Fuel}_{\text{Heat Cogen}}$** **3) $\text{Vol. Fuel}_{\text{Elec CCS}} = (\text{Elec}_{CCS} / \text{Elec}_{Total}) * \text{Vol. Fuel}_{\text{Elec Cogen}}$** **4) $\text{Vol. Fuel}_{\text{Heat Cogen}} = \text{Total Fuel}_{\text{Heat \& Power}} * (\text{Heat}_{Total} / e_{Heat}) / (\text{Heat}_{Total} / e_{Heat} + \text{Elec}_{Total} / e_{Elec})]$** **5) $\text{Vol. Fuel}_{\text{Elec Cogen}} = \text{Total Fuel}_{\text{Heat \& Power}} - \text{Vol. Fuel}_{\text{Heat Cogen}}$**					
	$\text{Emissions}_{\text{Off-Site Heat and Power Co-Generation}}$	kg of CO_2 ;kg CH_4 ; kg N_2O	N/A	N/A	N/A	Quantity being calculated based on quantity of heat and power purchased from third party facilities.
	Proportionate Volume of Fossil Fuels Consumed to Generate Heat and Power at Off-Site Facilities for Use by the CCS Project / Vol. Fuel_{CCS}	L/ m^3/ Other	Calculated	Calculated relative to the metered quantities of thermal energy and electricity delivered to the CCS 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 CCS 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.
	Volume of Fossil Fuels Consumed to Generate Heat at Off-Site Cogeneration Facilities for Use by the CCS Project / Vol. $\text{Fuel}_{\text{Heat CCS}}$	L/ m^3/ Other	Calculated	Calculated based on amount of heat used by the CCS project as compared to the total heat output from the third party cogeneration unit.	Monthly	Calculated according to best practice guidance from the Climate Registry General Reporting Protocol v1.1[8]
	Volume of Fossil Fuels Consumed to Generate Electricity at Off-Site Cogeneration Facilities for Use by the CCS Project / Vol. $\text{Fuel}_{\text{Elec CCS}}$	L/ m^3/ Other	Calculated	Calculated based on amount of electricity used by the CCS project as compared to the total electricity output from the third party cogeneration unit.	Monthly	Calculated according to best practice guidance from the Climate Registry General Reporting Protocol v1.1
	Total Volume of Fossil Fuels Consumed to Generate Heat and Power at Off-Site Cogeneration Facilities / Total $\text{Fuel}_{\text{Heat \& Power}}$	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 CCS project.	Continuous metering.	Continuous direct metering represents the industry practice and the highest level of detail.
	Total Quantity of Thermal Energy Supplied to the CCS Project from Off-Site Generation Facilities / $\text{Heat}_{\text{CCS Project}}$	GJ	Measured	Direct metering of quantity of thermal energy delivered to the CCS 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	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

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[8] The Climate Registry General Reporting Protocol Version 1.1. May 2008. Refer to Section 12.3, page 71 for cogeneration emission calculation equations. http://www.theclimateregistry.org/resources/protocols/general-reporting-protocol/

				heat transfer medium to and from the CCS 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.		transfer medium is consistent with best practices.
	Total Quantity of Electricity Supplied to the CCS Project by Cogeneration Facilities / Elec $_{\text{CCS Project}}$	GJ	Measured	Direct metering of the quantity of electricity delivered to the CCS Project from third party cogeneration plants or other direct connected power generation facilities. Note that grid electricity usage is accounted for under a separate SSR and should not be included in this calculation.	Continuous Metering	Continuous direct metering represents the industry practice and the highest level of detail.
	Total Quantity of Thermal Energy Generated by Facilities that Provide Heat to the CCS Project / Heat $_{\textbf{Total}}$	GJ	Measured	Direct metering of quantity of thermal energy delivered to all end users by the cogeneration plant (including the CCS 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 Generated by Facilities that Provide Electricity to the CCS Project /	GJ	Measured	Direct metering of quantity of electricity delivered to all direct connected facilities from the cogeneration plant (including the CCS facilities) and metering of the	Continuous Metering	Continuous direct metering represents the industry practice and the highest level of detail.

	Elec $_{Total}$			total electricity distributed to the regional electricity grid.		
	Total Volume of Fossil Fuels Consumed to Generate Heat at Off-Site Cogeneration Facilities / Vol. Fuel $_{Heat\ Cogen}$	L/ m^3/ Other	Calculated	Calculated based on heat generation efficiency of cogeneration unit.	Monthly	Calculated according to best practice guidance from the Climate Registry General Reporting Protocol v1.1
	Total Volume of Fossil Fuels Consumed to Generate Electricity at Off-Site Cogeneration Facilities / Vol. Fuel $_{Elec\ Cogen}$	L/ m^3/ Other	Calculated	Calculated based on heat generation efficiency of cogeneration unit.	Monthly	Calculated according to best practice guidance from the Climate Registry General Reporting Protocol v1.1
	Efficiency of Heat Generation at Third Party Cogeneration Unit / e $_{Heat}$	-	Estimated	Estimated based on total quantity of thermal energy output from cogeneration unit and input energy content of fuels combusted by the cogeneration unit. If a heat generation efficiency is unavailable, use a default efficiency of 80%.[9]	Annual	Estimation is reasonable given consistency of cogeneration unit operations.
	Efficiency of Electricity Generation at Third Party Cogeneration Unit / e $_{Elec}$	-	Estimated	Estimated based on total quantity of electricity output from cogeneration unit and input energy content of fuels combusted by the cogeneration unit. If an electric efficiency is unavailable use a default efficiency of 35%.[10]	Annual	Estimation is reasonable given consistency of cogeneration unit operations.
	CO_2 Emissions Factor for Each Type of Fossil Fuel / EF Fuel $_{i\ CO2}$	kg $CO_{2}{}_{3}$ per L, m^3 or other	Estimated	From Environment Canada reference documents. Refer to Appendix B	Annual	Reference values adjusted annually as part of Environment Canada's National Inventory Report.

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[9] A default thermal efficiency of 80% may be used to allocate emissions to purchased thermal energy used by the CCS project if a site specific thermal efficiency cannot be obtained. This assumption is consistent with Alberta Environment guidance under the Specified Gas Emitters Regulation (http://environment.alberta.ca/documents/Compliance_Guidance_v4.0.pdf).

[10] A default electrical efficiency of 35% may be used to allocate emissions to electricity purchased from third party cogeneration units for use by the CCS project if a site specific electrical efficiency cannot be obtained. This assumption is consistent with the Climate Registry General Reporting Protocol Version 1.1.

	CH_4 Emissions Factor for Each Type of Fossil Fuel / EF Fuel $_{i\ CH4}$	kg CH_4 per L, m^3 or other	Estimated	From Environment Canada reference documents. Refer to Appendix B	Annual	Reference values adjusted annually as part of Environment Canada's National Inventory Report.
	N_2O Emissions Factor for Each Type of Fossil Fuel / EF Fuel $_{i\ N2O}$	kg N_2O per L, m^3 or other	Estimated	From Environment Canada reference documents. Refer to Appendix B	Annual	Reference values adjusted annually as part of Environment Canada's National Inventory Report.
P10 On-Site Heat and Power Co-Generation	**Emissions $_{\text{On-Site Heat and Power Co-Generation}}$ = $\sum$ (Vol. Fuel $_{CCS}$ * EF Fuel $_{CO2}$); $\sum$ (Vol. Fuel $_{CCS}$ * EF Fuel $_{CH4}$) ; $\sum$ (Vol. Fuel $_{CCS}$ * EF Fuel $_{N2O}$)** Where, **1) Vol. Fuel $_{CCS}$ = Vol. Fuel $_{\text{Heat CCS}}$ + Vol. Fuel $_{\text{Elec CCS}}$** **2) Vol. Fuel $_{\text{Heat CCS}}$ = (Heat $_{CCS}$ / Heat $_{Total}$)* Vol. Fuel $_{\text{Heat Cogen}}$** **3) Vol. Fuel $_{\text{Elec CCS}}$ = (Elec $_{CCS}$ / Elec $_{Total}$)* Vol. Fuel $_{\text{Elec Cogen}}$** **4) Vol. Fuel $_{\text{Heat Cogen}}$ = Total Fuel $_{\text{Heat \& Power}}$ * (Heat $_{Total}$ /e $_{Heat}$) / (Heat $_{Total}$ /e $_{Heat}$+ Elec $_{Total}$/ e $_{Elec}$)]** **5) Vol. Fuel $_{\text{Elec Cogen}}$ = Total Fuel $_{\text{Heat \& Power}}$ - Vol. Fuel $_{\text{Heat Cogen}}$**					
	Emissions $_{\text{On-Site Heat and Power Co-Generation}}$	kg of CO_2 ;kg CH_4 ; kg N_2O	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 Cogeneration Facilities for Use by the CCS Project / Vol. Fuel $_{CCS}$	L/ m^3/ Other	Calculated	Calculated relative to the metered quantities of thermal energy and electricity delivered to the CCS 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 CCS 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.
	Volume of Fossil Fuels Consumed to Generate Heat at On-Site Cogeneration Facilities for Use by	L/ m^3/ Other	Calculated	Calculated based on amount of heat used by the CCS project as compared to the total heat output from the on-site cogeneration unit.	Monthly	Calculated according to best practice guidance from the Climate Registry General Reporting Protocol v1.1[11]

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[11] The Climate Registry General Reporting Protocol Version 1.1. May 2008. Refer to Section 12.3, page 71 for cogeneration emission calculation equations. http://www.theclimateregistry.org/resources/protocols/general-reporting-protocol/

	the CCS Project / Vol. Fuel $_{\text{Heat CCS}}$					
	Volume of Fossil Fuels Consumed to Generate Electricity at On-Site Cogeneration Facilities for Use by the CCS Project / Vol. Fuel $_{\text{Elec CCS}}$	L/ m^3/ Other	Calculated	Calculated based on amount of electricity used by the CCS project as compared to the total electricity output from the on-site cogeneration unit.	Monthly	Calculated according to best practice guidance from the Climate Registry General Reporting Protocol v1.1
	Total Volume of Fossil Fuels Consumed to Generate Heat and Power at the Combined Heat and Power Generation Facilities / Total Fuel $_{\text{Heat \& Power}}$	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 CCS project.	Continuous metering.	Continuous direct metering represents the industry practice and the highest level of detail.
	Total Quantity of Thermal Energy Supplied to the CCS Project from Cogeneration Facilities / Heat $_{\text{CCS Project}}$	GJ	Measured	Direct metering of quantity of thermal energy delivered to the CCS 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 CCS 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	GJ	Measured	Direct metering of the quantity of electricity delivered to the CCS Project from third party	Continuous Metering	Continuous direct metering represents the industry practice and the highest level

	Cogeneration Facilities / Elec$_{\text{CCS Project}}$			cogeneration plants or other direct connected power generation facilities. Note that grid electricity usage is accounted for under a separate SSR and should not be included in this calculation.		of detail.
	Total Quantity of Thermal Energy Supplied to End Users by the Cogeneration Facility in the Project Condition / Heat$_{\text{Cogen}}$	GJ	Measured	Direct metering of quantity of thermal energy delivered to all end users by the cogeneration plant (including the CCS 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 Cogeneration Facility in the Project Condition / Elec$_{\text{Cogen}}$	GJ	Measured	Direct metering of quantity of electricity delivered to all direct connected facilities from the cogeneration plant (including the CCS facilities) and metering of the total electricity distributed to the regional electricity grid.	Continuous Metering	Continuous direct metering represents the industry practice and the highest level of detail.
	Total Volume of Fossil Fuels Consumed to Generate Heat at On-Site Cogeneration Facilities / Vol. Fuel$_{\text{Heat Cogen}}$	L/ m^3/ Other	Calculated	Calculated based on heat generation efficiency of cogeneration unit.	Monthly	Calculated according to best practice guidance from the Climate Registry General Reporting Protocol v1.1
	Total Volume of Fossil Fuels Consumed to Generate Electricity at	L/ m^3/ Other	Calculated	Calculated based on heat generation efficiency of cogeneration unit.	Monthly	Calculated according to best practice guidance from the Climate Registry General

	On-Site Cogeneration Facilities / Vol. Fuel $_{\text{Elec Cogen}}$					Reporting Protocol v1.1
	Efficiency of Heat Generation at On-Site Cogeneration Unit / e $_{\text{Heat}}$	-	Estimated	Estimated based on total quantity of thermal energy output from cogeneration unit and input energy content of fuels combusted by the cogeneration unit. If a site-specific heat generation efficiency is unavailable, use a default efficiency of 80%.[12]	Annual	Estimation is reasonable given consistency of cogeneration unit operations.
	Efficiency of Electricity Generation at On-site Cogeneration Unit / e $_{\text{Elec}}$	-	Estimated	Estimated based on total quantity of electricity output from cogeneration unit and input energy content of fuels combusted by the cogeneration unit. If a site-specific electric efficiency is unavailable use a default efficiency of 35%.[13]	Annual	Estimation is reasonable given consistency of cogeneration unit operations.
	CO_2 Emissions Factor for Each Type of Fossil Fuel / EF Fuel $_{\text{i CO2}}$	kg CO_2 per L, m^3 or other	Estimated	From Environment Canada reference documents. Refer to Appendix B	Annual	Reference values adjusted annually as part of Environment Canada's National Inventory Report.
	CH_4 Emissions Factor for Each Type of Fossil Fuel / EF Fuel $_{\text{i CH4}}$	kg CH_4 per L, m^3 or other	Estimated	From Environment Canada reference documents. Refer to Appendix B	Annual	Reference values adjusted annually as part of Environment Canada's National Inventory Report.
	N_2O Emissions Factor for Each Type of Fossil Fuel / EF Fuel $_{\text{i N2O}}$	kg N_2O per L, m^3 or other	Estimated	From Environment Canada reference documents. Refer to Appendix B	Annual	Reference values adjusted annually as part of Environment Canada's National Inventory Report.
P11 Inspection	**Emissions $_{\text{Inspection/ Maintenance}}$ = $\sum$ (Vol. Fuel $_{\text{Inspection/ Maintenance}}$* EF Fuel $_{\text{i CO2}}$); $\sum$ (Vol. Fuel $_{\text{Inspection/ Maintenance}}$ * EF Fuel $_{\text{i CH4}}$); $\sum$ (Vol. Fuel $_{\text{Inspection/ Maintenance}}$ * EF Fuel $_{\text{i N2O}}$);**					

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[12] A default thermal efficiency of 80% may be used to allocate emissions to purchased thermal energy used by the CCS project if a site specific thermal efficiency cannot be obtained. This assumption is consistent with Alberta Environment guidance under the Specified Gas Emitters Regulation (http://environment.alberta.ca/documents/Compliance_Guidance_v4.0.pdf).

[13] A default electrical efficiency of 35% may be used to allocate emissions to electricity purchased from third party cogeneration units for use by the CCS project if a site specific electrical efficiency cannot be obtained. This assumption is consistent with the Climate Registry General Reporting Protocol Version 1.1.

and Maintenance of CCS Facilities	Emissions $_{\text{Inspection/ Maintenance}}$	kg CO_2; kg CH_4; kg N_2O;	N/A	N/A	N/A	Quantity being calculated based on quantity of fossil fuels used for inspection and maintenance of CCS Facilities.
	Volume of Each Type of Fuel Used for Inspection and Maintenance of CCS Facilities/ Vol. Fuel $_i$	L / m^3 / other	Measured	Direct metering of volume of fuel consumed by each piece of equipment used during inspection and maintenance activities	Monthly Reconciliation	Frequency of reconciliation provides for reasonable diligence.
	CO_2 Emissions Factor for Each Type of Fuel / EF Fuel $_{i\ CO2}$	kg CO_2 per L / m^3 / other	Estimated	From Environment Canada reference documents. Refer to Appendix B	Annual	Reference values adjusted annually as part of Environment Canada's National Inventory Report.
	CH_4 Emissions Factor for Each Type of Fuel / EF Fuel $_{i\ CH4}$	kg CH_4 per L / m^3 / other	Estimated	From Environment Canada reference documents. Refer to Appendix B	Annual	Reference values adjusted annually as part of Environment Canada's National Inventory Report.
	N_2O Emissions Factor for Each Type of Fuel / EF Fuel $_{i\ N2O}$	kg N_2O per L / m^3 / other	Estimated	From Environment Canada reference documents. Refer to Appendix B	Annual	Reference values adjusted annually as part of Environment Canada's National Inventory Report.
P20 Fugitive Emissions from the Geological Storage Formation	**Emissions $_{\text{Leakage from Saline Formation}}$ = Mass CO_2 $_{\text{leaked}}$**					
	Mass of CO_2 leaked from the Geological Storage Complex / Mass CO_2 $_{\text{leaked}}$	kg	Estimated	Mass of CO_2 leaked from the formation would have to be estimated based on the type of leakage event, its duration and the estimated leakage rate from the injection zone. Methods to measure or estimate (directly or indirectly) the emission of CO_2 is addressed in the project specific measurement, monitoring and verification plan.	N/A	Estimation would be required for reporting to the regulatory authority. Direct measurement is likely not possible, but the use of engineering estimates would be a reasonable approach in the event leakage occurs.

5.2.5 Permanence and Reversibility

The proposed protocol is not applicable to CO_2-enhanced hydrocarbon recovery and is only applicable to the injection of CO_2 into deep saline formations where hydrocarbon production is not possible. Therefore, there are no risks related to CO_2 recirculation within the formation or leakage from producing wells.

In the proposed protocol, permanence will be addressed on a project-specific basis through the implementation of a complete measurement, monitoring and verification (MMV) plan. For the Quest CCS Project, an MMV Plan was required by the Terms of reference pursuant to the Canadian Environmental Assessment Act and the Alberta Environmental Protection and Enhancement Act, Environmental Assessment Regulation. The MMV plan was included in the full Environmental Assessment, submitted to the Governments of Canada and Alberta in November 2010. For further information refer to Appendix A of the Shell Quest CCS Project Environmental Assessment. The geological storage scheme is defined in detail in the Quest Carbon Capture and Storage Project Directive 65: Application for an Acid Gas Storage Scheme submitted to the Energy Resources Conservation Board (ERCB) in November 2010.

The injection and storage of CO_2 in deep saline formations will result in permanent storage. The MMV program is designed to show that CO_2 has been stored permanently within the target formation.

5.2.6 Comparison of Project and Baseline Sources and Sinks

The baseline and project conditions were assessed against each other to determine the scope for reductions quantified under this protocol. All SSRs identified in Table 5 and Table 8 above, are listed in Table 10, below. Emissions that increase or decrease materially as a result of the project must be included and associated greenhouse gas emissions must be quantified as part of the project condition. SSRs were either included or excluded depending on how they were impacted by the project condition. SSRs that are not expected to change between baseline and project condition have been excluded from the quantification. Other exclusions have been justified on a SSR specific level.

Table 10: Comparison of SSRs

Identified SSR	Baseline (C, R, A)**	Project (C, R, A)**	Include or Exclude from Quantification	Justification for Exclusion/Inclusion
Upstream SSRs During Project				
P4 Production and Delivery of Material Inputs used in CO_2 Capture Process	N/A	Related	Exclude	GHG emissions from the production and delivery of material inputs used in the CO_2 capture process are negligible compared to the expected GHG reductions realized from CCS projects. See Appendix A for further justification.
P5 Extraction/Processing and Transportation of Fuels Used On-Site for Heat and Power Generation	N/A	Related	Include	This SSR is likely to have a material impact on projects
P6 Extraction/Processing and Transportation of Fuels Used Off-Site for Heat and Power Generation	N/A	Related	Include	This SSR is likely to have a material impact on projects
P7 Extraction/Processing and Transportation of Fuels Used for Generation of Grid Electricity	N/A	Related	Exclude	For consistency with other government-approved protocols under the Alberta Offset System, this SSR has been excluded due to immateriality.
P8 Generation of Electricity for Use by CCS Facilities	N/A	Related	Include	This SSR is likely to have a material impact on projects
P9 Off-Site Heat and Power Co-Generation	N/A	Related	Include	This SSR is likely to have a material impact on projects
On-Site SSRs During Project				
B1 Industrial Process Emissions at Hydrogen Production Facility	Controlled	N/A	Include	This SSR is the data point against which all project emissions are subtracted and establishes the baseline emissions.
P10 On-Site Heat and Power Co-Generation	N/A	Controlled	Include	This SSR is likely to have a material impact on projects
P11 Inspection and Maintenance of CCS Facilities	N/A	Controlled	Include	This SSR is likely to have a material impact on projects
P12 Emission of CO_2 at Capture	N/A	Controlled	Exclude	The amount of vented CO_2 in the baseline is calculated

Site				from the metered amount of CO_2 captured and injected in the project condition. The protocol requires that this meter to be located downstream of the capture site and transport system, right at the point(s) of injection for accuracy (direct calculation method). In some project cases, all of the CO_2 from hydrogen production was emitted in the baseline, thus any fugitive emissions that occur upstream of the injection wells in the project condition would be equivalent to emissions that would have occurred in the baseline and can therefore be excluded from the quantification. This protocol does not allow indirect calculation methods due to its decreased accuracy.
P13 Fugitive Emissions at Capture Site	N/A	Related	Exclude	
P14 Venting of CO_2 During Compression/Dehydration	N/A	Controlled	Exclude	
P15 Fugitive Emissions During Compression/ Dehydration	N/A	Related	Exclude	
P16 Venting of CO_2 During Transportation	N/A	Controlled	Exclude	
P17 Fugitive Emissions During Transportation	N/A	Related	Exclude	
P18 Venting of CO_2 at Injection Well Sites	N/A	Controlled	Exclude	
P19 Fugitive Emissions at Injection Well Sites	N/A	Related	Exclude	
P20 Fugitive Emissions from the Geological Storage Formation	N/A	Related	Include	Under normal operation, this SS may be neglected, however to account for leakage events, this SS is included. A measurement, monitoring and verification plan, as described in Section **Error! Reference source not found.** shall address the quantification of this SS in the event of fugitive emissions from the geological storage formation.
Downstream SSRs During Project				
P21 Loss, Disposal, or Recycling of Materials Used in CO_2 Capture Processes	N/A	Related	Exclude	GHG emissions from the loss, disposal, or recycling of materials used in the CO_2 capture process are negligible compared to the expected project size. See Appendix A for further justification.
Construction/Decommissioning SSRs				
P1 Production and Delivery of Materials Used for Construction of CCS Facilities	N/A	Related	Exclude	This one-time only source of GHG 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 Offset System. See Appendix A for

				further justification.
P2 Land Clearance and Soil Carbon Loss from Construction of CCS Facilities	N/A	Related	Exclude	This one-time only source of GHG emissions is negligible compared to the expected size and long lifetime of the project. See Appendix A for further justification.
P3 Construction of CCS Facilities	N/A	Related	Exclude	This one-time only source of GHG 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 Offset System. See Appendix A for further justification.

**Where C is Controlled, R is Related, and A is Affected.

6 State of Science — Findings, Gaps, Issues

Although many of the component and/or enabling technologies required for CO_2 capture are well known, gaps in knowledge are in the practical and/or commercial demonstration of integrated systems. This demonstration is essential to prove the cost of CO_2 capture and its use on a large scale. Operating experience is also needed to test system reliability, improved methods of system integration, methods to reduce the energy requirements for CO_2 capture, improved process control strategies and the use of optimized functional materials for the implementation of capture processes. As such developments are realized, environmental issues associated with the capture of CO_2 and other pollutants in these systems should also be re-assessed from a perspective involving the whole capture-transport-storage operation.

7 Consultation Workshop Results

This document has been produced based on an rigorous internal working group assessment at Shell Canada for the Quest CCS project. A public consultation workshop will review this document to continue to ensure it properly accommodates to all relevant stakeholders opinions and will be updated with this input as it is available.

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9 Appendix A – Supporting Calculations

A1 – Perfluorocarbon impact

In general, perfluorocarbons used as a tracer gas are mixed with the dense phase CO_2 prior to injection at a rate of approximately one part per trillion by volume.

The specified gas emission regulation defines the accepted global warming potential based on 100 year time horizons for the perfluorocarbons as:

Chemical Name	Formula	GWP (CO_2e 100y)
Perfluoromethane	CF4	6500
Perfluoroethane	C2F6	9200
Perfluoroproprane	C3F8	7000
Perfluorobutane	C4F10	7000
Perfluorocyclobutane	C4F8	8700
Perfluoropentane	C5F12	7500
Perfluorohexane	C6F14	7400

The regulated perfluorocarbon with the highest GWP as shown in the table above has a GWP of 9200. As a worst case scenario, it is assumed that this gas is used as a tracer, and that one part per trillion is used. For every tonne of CO_2 sequestered in the project, the equivalent GWP sequestered of perfluorocarbon is on the order of $9.2x10^{-9}$ tonnes. For Shell Quest, if one million tonnes of CO_2 is sequestered in a year, the equivalent of 0.009 tonnes (9 grams) CO_2e of perfluorocarbon is sequestered.

Further to the above estimate, it will be conservative for project developers to neglect sequestrations in the project quantification methods.

A2 – Exclusion of "P4 Production and Delivery of Material Inputs used in CO_2 Capture Process"

Preliminary amine make-up estimates show that an MDEA capture system requires approximately 0.003% amine make-up per cycle[14]. This is due to fugitive losses, degradation and spoilage.

For the Quest project, treated gas from each amine absorber is further treated in a wash water vessel to reduce amine carry-over to the pressure swing adsorber (PSA) units. The concentration of amine in the carry-over will be less than 1 part per million by weight (ppmw) amine, and the gas temperature will be reduced from 39°C to 35°C. Each wash section consists of a wash water vessel, circulating water wash pumps and a circulating water cooler.

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[14] FIASCHI et. al.

A continuous flow of fresh make-up water is supplied to the wash water vessel while a continuous purge of wash water is removed from the system by the pumps. This maintains the amine concentration in the circulating water at a low level to facilitate removal of entrained amine from the gas stream. The purge water that is pumped from the water wash system is sent to the Shell Scotford waste water treatment plant. Maximum expected amine loss into waste water is 36 kg/h of amine from the three wash water systems. The maximum monthly amine make-up requirement is 25 m^3.

The less than 1 ppmw amine, which potentially could carry over from the wash water section to the PSA, is less than 0.115 kg/h. Once in the PSA, this amine flows along with the tail gas from the PSA to the hydrogen manufacturing unit (HMU) furnaces where it is incinerated by the HMU furnace burners.

At an industrial scale life cycle analysis, this has been estimated to translate to approximately 15,000 tonnes over a 15 year lifetime[14] of a 344MW coal power plant, or approximately 1000 tonnes CO_2 / year while allowing for the capture of over 4.9 million tonnes of CO_2.

While this figure is not directly comparable to the Shell Quest project, it does provide a sense of the order of magnitude of the emissions associated with MDEA production / consumption relative to that which they capture during their useful life. As such, it is estimated that MDEA for use in CCS technology will result in 300 times more emission reductions than the emissions produced for the manufacture / consumption of the same volume of amine. MDEA production emissions are estimated to be 0.3% of the sequestered emissions for the Shell Quest project.

A3 – Exclusion of "P21 Loss, Disposal, or Recycling of Material Used in CO_2 Capture Process"

For the sake of simplicity and conservativeness in this analysis, it is assumed here that all consumed amine is combusted and the emissions from this combustion are released to the atmosphere. MDEA contains 5 carbon atoms so that for every mole of MDEA (Molecular mass = 119.163g/mol), 5 CO_2 moles are formed (Molecular mass = 44g/mol). On a weight per weight basis, this means each unit of MDEA consumed will degrade to 1.84 units of CO_2. Based on preliminary estimates for the Shell Quest project, approximately 315 tonnes of MDEA will be consumed each year, meaning the total CO_2 impact from MDEA disposal is less than 581 tonnes of CO_2, while yearly reductions are on the order of 1,000,000tCO_2.

A4 – Exclusion of "P2 Land Clearance and Soil Carbon Loss from Construction of CCS Facilities"

For the construction of CCS facilities similar to the Shell Quest project, the majority of new clearing will come in the form of pipeline right of way clearing. As an example estimate, the Shell Quest project will have approximately 80km of pipeline through mixed use land (agricultural, unused cleared, forest, etc). An approximate right of way width is assumed to be 15m. The total land area impacted is therefore 1.2km^2 or 120 ha.

Based on western Canadian research results, it is expected that carbon lost from the soil during construction will not exceed 0.84 tonnes CO2e / h.[15]. The total emissions from soil carbon loss is not expected to exceed 101 tCO_2e in the lifetime of the project while the yearly reductions of the project are on the order of 1,000,000tCO_2.

A5 – Exclusion of "P1 Production and Delivery of Materials Used for Construction of CCS Facilities" and "P3 Construction of CCS Facilities"

As evidence for justification for the exclusion of GHG emission sources related to the construction of CCS facilities similar to the Shell Quest project, preliminary construction phase GHG estimates were prepared by AMEC in 2001. The AMEC report, *AOSP Updates to Construction Phase Greenhouse Gas Emissions Estimates*, is a revision from a report generated by AGRA in 2000, *AOSP Construction Phase Preliminary GHG Estimates*. Table A5 provides a breakdown of the emissions associated with the construction of the Shell Quest Project.

Table A5: Shell Quest Construction Emissions

Parameter	Shell Quest Project
On-Site Fuel Consumption	795
On-Site Land Use Changes	120
On-Site Sub-Total (tCO_2e)	**915**
Off-Site Industrial Emissions	3,413
Off-Site Fuel Consumption	417
Off-Site Sub-Total (tCO_2e)	**3,830**
Total GHG Footprint (tCO_2e)	**4,745**

Based on the preliminary estimates associated with the construction for the Shell Quest Project, approximately 4,745 tCO_2e will be emitted, while yearly reductions are on the order of 1,000,000 tCO_2e. The construction emissions are negligible compared to the lifetime emission reductions generated by the Shell Quest Project.

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[15] AENV, 2007 Soil Carbon Custom Coefficient/ Protocol Guidance Document

10 Appendix B - Emission Factors

Table B1: Combustion Emission Factors for Gasoline and Diesel[16]

Fuel	**Fuel Combustion Emission Factors (kg GHG/ litre fuel)**		
	CO_2	**CH_4**	**N_2O**
Gasoline	2.289	0.00056	0.00066
Diesel	2.663	0.00015	0.00022

Table B2: Emission Factors for Natural Gas and NGL's

Source	**Emission Factors**		
	CO_2	**CH_4**	**N_2O**
	g/m^3	**g/m^3**	**g/m^3**
Natural Gas			
Electric Utilities	1891	0.49	0.049
Industrial	1891	0.037	0.033
Producer Consumption	2389	6.5	0.06
Pipelines	1891	1.9	0.05
Cement	1891	0.037	0.034
Manufacturing Industries	1891	0.037	0.033
Residential, Construction, Commercial/Institutional, Agriculture	1891	0.037	0.035
	g/L	**g/L**	**g/L**
Propane			
Residential	1510	0.027	0.108
All Other Uses	1510	0.024	0.108
Ethane	976	N/A	N/A
Butane	1730	0.024	0.108

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[16] Environment Canada, Fuel Combustion Emission Factors

The following emission factors are used for fuel extraction and production.

Table B3: Emission Intensity of Fuel Extraction and Production (Diesel and Gasoline)[17]

Diesel		
Production		
Emissions Factor (CO_2)	0.138	kg CO_2 per Litre
Emissions Factor (CH_4)	0.0109	kg CH_4 per Litre
Emissions Factor (N_2O)	0.000004	kg N_2O per Litre
Natural Gas		
Extraction		
Emissions Factor (CO_2)	0.043	kg CO_2 per m^3
Emissions Factor (CH_4)	0.0023	kg CH_4 per m^3
Emissions Factor (N_2O)	0.000004	kg N_2O per m^3
Processing		
Emissions Factor (CO_2)	0.090	kg CO_2 per m^3
Emissions Factor (CH_4)	0.0003	kg CH_4 per m^3
Emissions Factor (N_2O)	0.000003	kg N_2O per m^3
Gasoline		
Production		
Emissions Factor (CO_2)	0.138	kg CO_2 per Litre
Emissions Factor (CH_4)	0.0109	kg CH_4 per Litre
Emissions Factor (N_2O)	0.000004	kg N_2O per Litre

Table B4: Emission Intensity of Grid Electricity in Alberta[18]

Grid Electricity	**GHG Intensity (t CO_2e/MWh)**
Emission Factor	0.65 for the use of grid electricity

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[17] Emissions by the Upstream Oil and Gas Industry. CAPP. 2004.

[18] Refer to the Alberta Environment Technical Guidance for Offset Protocol Developers document to confirm that the most up to date grid intensity emission factor is being used. http://environment.gov.ab.ca/info/library/8331.pdf