QUANTIFICATION PROTOCOL FOR REDUCTION OF METHANE EMISSIONS FROM OIL AND GAS FACILITIES

Submitted to:

Alberta Environment

February 2009

Prepared By: Blue Source Canada

Acknowledgements

This protocol is based on the Technical Seed Document entitled *A Protocol for Methane Emission Reductions for Greenhouse Gas Credits* dated October, 2008. This document was prepared as a collaborative effort by Keyera, Husky, EnCana, Shell and Nexen for submission to Alberta Environment.

Disclaimer

The following protocol document was prepared for Alberta Environment. The document will undergo a round of technical review and a broader round of stakeholder review through 2009. Future versions of the protocol document will incorporate the feedback from the review process.

Table of Contents

List of Figures

List of Tables

1.0 Project and Methodology Scope and Description

This quantification protocol is written for the oil and gas industry or the methane emissions reduction project developer. The opportunity for generating carbon offsets with this protocol arises from the direct and indirect reductions of greenhouse gas (GHG) emissions resulting from the identification and reduction of methane emissions from venting and other fugitive emissions at oil and gas facilities. Sources of fugitive emissions at oil and gas facilities may include equipment leaks, tanks, instrument venting, etc[1]. Some familiarity with, or general understanding of, the operation of oil and gas production and processing facilities is assumed.

Projects included under this protocol must be able to demonstrate a reduction in methane emissions using direct quantification, with virtually continuous monitoring and complete coverage of the project site. Projects which rely exclusively on traditional leak detection methods such as the bag and stopwatch or "sniffing" techniques are excluded from this protocol, as these methods do not fulfill the requirement of continuous monitoring.

1.1 Protocol Scope and Description

This protocol quantifies emission reductions created by the identification, quantification, and reduction of planned and / or unplanned fugitive methane emissions from oil and gas production processes.

Methane emissions from oil and gas facilities are difficult to assess given the large number of potential sources, random occurrence, transient behaviour, poor correlation of emissions with facility activity levels, diffuse nature, and the difficulty of area air monitoring to detect these emissions[2]. However, the use of remote sensing technologies allows for the accurate quantification of these emissions through continuous monitoring and complete coverage of the project site.

Planned Emissions

Planned emissions are known emissions that result from operational practices. Operational practices that use process gas for "blanketing purposes", or equipment that uses the pressure of the process gas as energy to drive the equipment (valves, pumps etc.) and then releases it to the atmosphere, are examples of planned emissions. Additionally, some venting practices are planned emissions that can result in intermittent and / or highly variable emission rates that are difficult to quantify, but could afford significant reductions of GHGs if reduced.

[1] Canadian Association of Petroleum Producers (CAPP). (2003). CH4 and VOC Emissions: Volume 4. Retrieved at http://www.capp.ca/raw.asp?x=1&dt=NTV&e=PDF&dn=84183

[2] ibid

Challenges exist for quantifying planned emissions as emission rates can be highly variable and / or intermittent. This is likewise the case with most venting situations~~.~~ where ~~I~~it is not usually a problem to locate the source of the vents, but determining the amount of gas being vented is difficult.

Unplanned Emissions

A relatively small number of fugitive sources usually accounts for the vast majority of the overall fugitive emissions at natural gas facilities. As a result, fugitive emissions are very difficult to quantify with certainty because they are dominated by a small number of unstable sources in unpredictable locations. Experience has shown that these random large fugitive emissions may go undetected even at facilities that are using the US EPA's stringent "Method 21" protocol that requires all potential leaking components to be visited at a prescribed frequency[3].

Given that planned and unplanned emissions are dominated by a small number of sources with unpredictable locations, as described above, the key challenge is in accurately quantifying emission reductions. This requires quantification of the source through direct measurement. Further, since source locations are unpredictable surveillance of the entire site is required. Given the potential variability over time, virtually continuous monitoring of emissions is also necessary to ensure accuracy. As such, emission reductions can be proven with certainty by using a direct quantification that provides complete coverage of the site combined with virtually continuous monitoring.

A summary of the technologies available for continuous monitoring at the time of writing of this protocol is provided in Appendix A. It is anticipated that additional technologies may become available during the protocol applicability period. These technologies would also be applicable, as long as they provide direct measurement, virtually continuous monitoring and complete site coverage and meet the minimum measurement and monitoring requirements of the protocol.

FIGURE 1.1 offers a process flow diagram for a typical project.

Current regulations governing methane emissions from oil and gas facilities in Alberta include Alberta Energy Resources Control Board (ERCB) Directive 060 (ERCB, 2006). The emission reductions contemplated under this protocol must be incremental to the emission reductions required by the above document.

[3] Petroleum Technology Alliance Canada Technology for Emission Reduction and Eco-Efficiency(TEREE) Steering Committee. (2007). *Review and Update of Methods Used for Air Emissions Leak Detection and Quantification*.

Regulatory incrementality will be demonstrated by ensuring that the facility is in regulatory compliance for the full duration of the baseline monitoring period and by measuring baseline emissions following implementation of a Direct Inspection and Maintenance (DI&M) leak detection and repair program that meets the requirements of the Directive. For those projects that were implemented prior to implementing a DI&M program, the baseline must be re-evaluated following implementation of the program. For facility's where a re-evaluation of baseline emissions is not practical, there is a flexibility mechanism that allows the facility to discount baseline emissions by an improvement factor to account for the expected impact of the DI&M program.

- ~~discounting baseline emissions by an annual improvement factor based on common industry practice. Common industry practice will be assessed based on observed improvements in industry fugitive emissions following the implementation of direct inspection and maintenance (DI&M) programs for leak detection and repair (as required to meet the requirements of the directive).~~

Due to the use of virtually continuous monitoring and complete site coverage it is anticipated that projects using measurement and monitoring techniques consistent with this protocol will be able to detect and fix sources of methane emissions that would not have been detected using the methods used in a typical DI&M program that meets the requirements of the Directive~~outlined in the above document~~.

Protocol Approach:

This protocol applies to projects where methane emissions are from oil and gas facilities and would otherwise have been emitted to the atmosphere. This protocol serves as a generic 'recipe' for project developers to follow in order to meet the measurement, monitoring and GHG quantification requirements.

Measurements may be inclusive of methane emissions from the following key sources[4]:

- Planned and unplanned venting; and
- Fugitive methane losses from the following sources:
  - Fittings and seals;
  - Instrument venting;
  - Glycol dehydrators;
  - Vapour from oil batteries;
  - Plant tank venting; and
  - Non routine venting (i.e. equipment failures, pressure releases).

The baseline condition for this protocol has been identified as the facility's methane emissions (planned and unplanned) during operation of the oil and / or gas production

[4] Canadian Association of Petroleum Producers (CAPP). (2003). *Calculating Greenhouse Gas Emissions*

facility prior to project implementation. The protocol approach includes determination of the baseline condition based on continuous monitoring of the project site for a period of one month, after the implementation of a DI&M leak detection and repair monitoring program that meets the requirements of ERCB Directive 060. ~~and the application of a discount to account for common industry practice and the impact of regulations.~~ Further, the facility must be in compliance with all applicable regulations during the baseline monitoring period.

Comment [KB1]: Flagged. TBD.

The project condition for this protocol has been identified as the facility's methane emissions during operation of the facility following project implementation. Project activities to reduce methane emissions may include reduced venting, detection and repair of fugitive equipment leaks, facility consolidation activities, etc. that would not have been conducted in the absence of the project.

Project emissions are measured continuously for a period of XX months each year. Monthly measurements are used by the project proponent to create an annual methane emission profile for the facility. Justification must be provided to explain how methane emissions are forecast for the months that are not measured. Alternatively the highest of the previous and following monitoring period values may be used to be conservative.

Comment [KB2]: TBD. To include further information about the selection of the duration of the monitoring period (i.e. data reviewed, studies conducted).

Project emissions are~~and~~ then compared with the quantity of methane emitted in the baseline. Emission reduction are generated based on the difference between project and baseline methane emissions at the facility. Note that methane emissions may go up in some months due to facility shutdowns, etc. and facility methane emissions for each month where emissions are monitored must be ~~accounted for and~~ included in the facility's emission profile~~summed on an annual basis~~ (i.e. project proponents may not exclude months when methane emissions have increased).

Note that in practice the primary output of methane from venting and fugitive losses would be to sales gas, with gas only being flared during emergency provisions. However~~, it is also possible that some gas streams may be flared. As such~~, at facilities that do not sell methane as an end product (i.e. gas production facilities) flaring may be the only option. It is therefore ~~to be conservative it is~~ assumed that at these facilities all methane whose emission is avoided in the project condition is flared. This is conservative. Alternatively, ~~there is~~is the protocol has a flexibility mechanism that allows the project proponent to demonstrate that gas is not flared.

This protocol is intended to apply from the date of project implementation forward. Given the data requirements, calculation of historical emissions reductions will not generally be contemplated~~ under this protocol~~. ~~Historical reductions may only be claimed if all measurement and monitoring requirements are satisfied and all necessary data was collected continuously from the date of project commissioning and through the entire project crediting period.~~

FIGURE 1.1: Process Flow Diagram for Project Condition

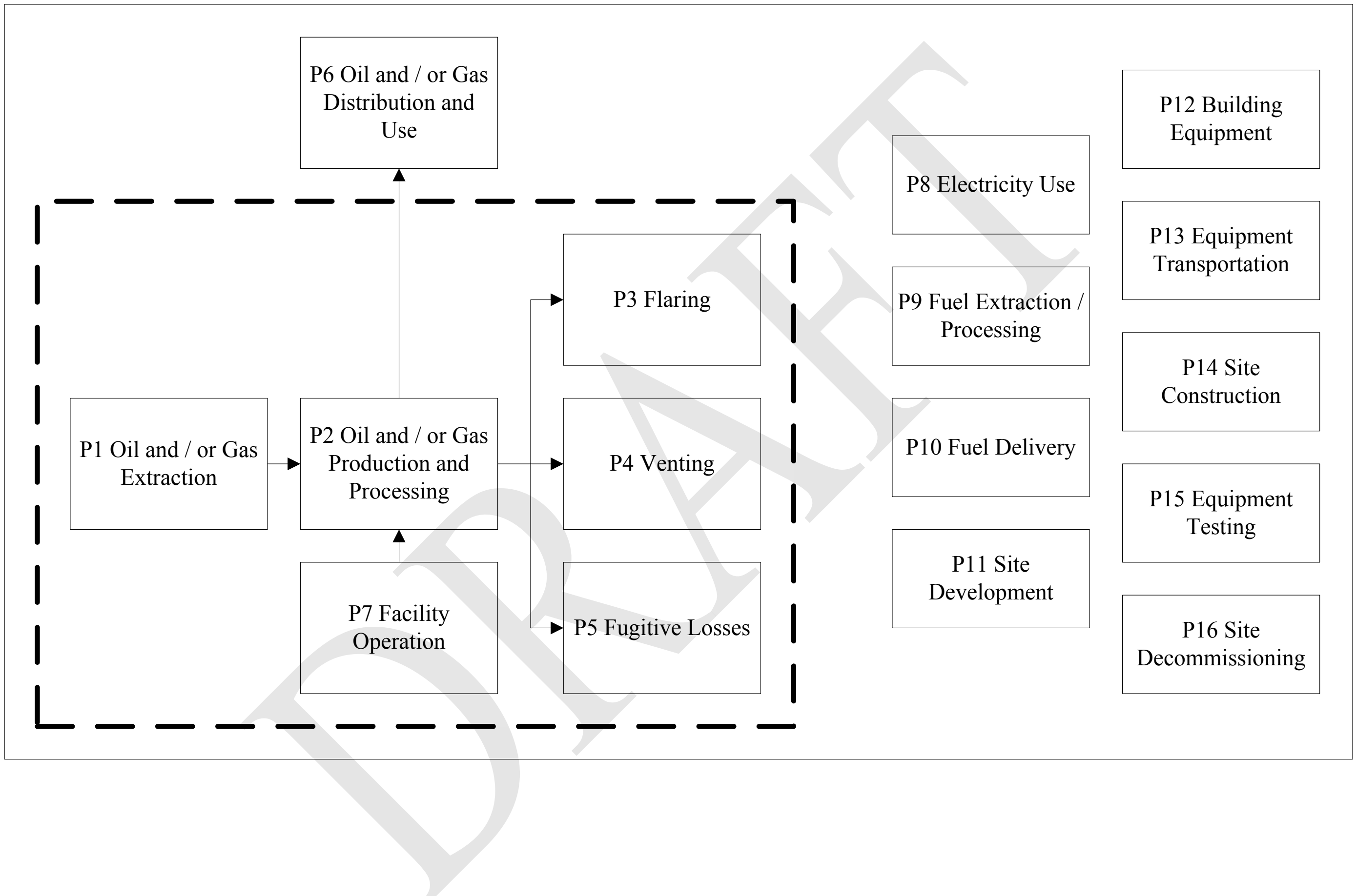
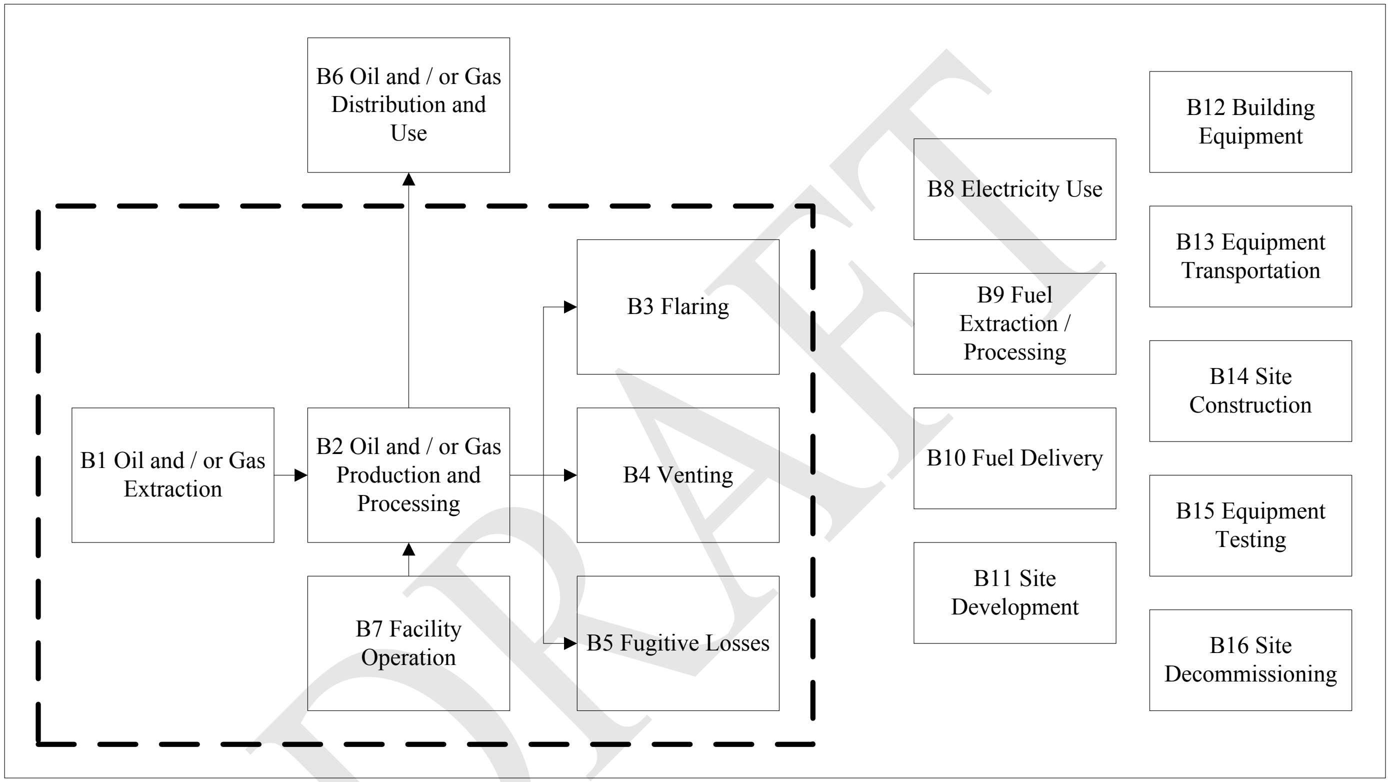


FIGURE 1.2: Process Flow Diagram for Baseline Condition



Protocol Applicability:

To demonstrate that a project meets the requirements under this protocol, the project developer must provide evidence that:

1. The fugitive emissions reduction project results in the removal of emissions that would otherwise have been released to the atmosphere as indicated by direct quantification of the baseline and project conditions using virtually continuous monitoring and complete coverage of the project site. Criteria for selection of an appropriate monitoring methodology are included in Appendix A;
2. To ensure functional equivalent between the project and baseline conditions, the fugitive emission reduction project must not require any re-permitting of the facility. Further, the facility must be operating and have an annual throughput of greater than 0 ~~e^3~~ m^3. Following any re-permitting of the facility that is unrelated to project activities, the baseline condition ~~may need to~~ should be re-evaluated.
3. The emissions captured under this protocol are not also reported under other applicable protocols. This is important given that this protocol uses an overall site methane emission calculation. Methane emission reductions reported under any other protocols such as the Engine Fuel Gas Management ~~or~~and Vent Gas Capture protocols must be subtracted from the total reductions calculated under this protocol in both the project and baseline conditions;
4. The facility is under regulatory compliance for the duration of the baseline emissions monitoring period. Further, the emission reductions achieved by the project are additional to those required by Alberta regulations as indicated by measuring (or re-assessing) the facility's baseline emissions following the implementation of a Direct Inspection and Maintenance (DI&M) program that meets the requirements of ~~the application of a baseline discount factor to account for the impacts of~~ ERCB Directive 060~~.~~; ~~This discount must be applied beginning on January 1st, 2010 when regulations require that all facilities have a leak detection and repair Direct Inspection and Maintenance (DI&M) program fully implemented. This approach is outlined in Appendix B;~~
5. The project proponent provides a complete list of process changes, repairs or other actions taken to reduce methane emissions. Further detail is provided in the quality assurance and quality control section of the protocol (section 2.6.2);
6. Reductions in methane emissions resulting from business as usual activities and required equipment replacements must be discounted from baseline emissions; and
7. The quantification of reductions achieved by the project is based on actual measurement and monitoring (except where indicated in this protocol) as indicated by the proper application of this protocol; and
   - The project must meet the requirements for offset eligibility as specified in the applicable regulation and guidance documents for the Alberta Offset System.

Protocol Flexibility:

Flexibility in applying the quantification protocol is provided to project developers in the following ways:

1. Instead of assuming that all methane captured in the project condition is flared on-site and released as CO_2 ,at facilities that do not sell methane as an end product, project proponents may provide evidence to demonstrate that gas is not flared. Evidence may include the use of schematic or process flow diagrams to demonstrate that gas could not have been flared based on the location of the emission source, an audit of facility emissions, etc.
2. Project proponents may propose a measurement and monitoring frequency other than what is outlined in this protocol, provided that the monitoring frequency allows for a level of accuracy consistent with the protocol requirements;
    a. This approach is applicable to projects at small facilities (i.e. single well batteries, satellite batteries, and field facilities) that involve a limited number of processes / equipment.
3. For projects that were initiated prior to January 1st, 2010 and whose baseline was measured prior to the implementation of a DI&M program that meets the requirements of ERCB Directive 060, the following alternate methodology is provided;
    a. Baseline emissions may be deducted by an improvement factor to account for the anticipated impact of implementing a DI&M program at the facility. This deduction must be applied beginning on January 1st, 2010 (i.e. the date when ERCB Directive 060 requires full implementation of a DI&M program at all facilities). The value of the improvement factor may be based on published studies of the impact of DI&M programs in other jurisdictions, facility data, etc. The project proponent must justify the use of this factor and it is recommended that the approach be approved by an independent third party to ensure accuracy; and and
    b. The quantification of the SSs B4 and B5 outlined in Table 2.5 would then be modified as follows:

$$\text{Emissions}_{\text{Methane (Baseline)}} = \text{Emissions}_{\text{Methane (Baseline)}} * (1 - \text{Improvement Factor})$$

If applicable, the developer must indicate and justify why flexibility provisions have been used.

1.2 Glossary of New Terms

Functional Equivalence	The Project and the Baseline provide the same function and quality of products or services. This type of comparison requires a common metric or unit of measurement (such as the barrels of oil produced) for comparison between the Project and Baseline activity (refer to the Project Guidance Document for the Alberta Offset System). For this protocol functional equivalence is established based on there being no change in facility permitting between the project and baseline condition. Further the facility must be operating within the same range. Note that throughput is not an appropriate unit of functional equivalence for fugitive emissions as they are not dependant on throughput but on the number of sources, hours operational, age of equipment, etc.
Planned Emissions:	Known emissions that result from operational practices and are generally stated in production accounting records. Examples include using process gas for blanketing purposes, and planned venting. The location of planned emissions is known, but the volumes may be difficult to quantify.
Unplanned Venting:	According to the Canadian Association of Petroleum Producers (CAPP) sources of unplanned venting include glycol dehydrator off-gas, loading/unloading losses, storage losses, pneumatic devices (e.g., chemical injection pumps, natural gas operated instrumentation), compressor start gas, purge gas and blanket gas that is discharged directly to the atmosphere and gas vented from drill-stem tests”[5].
Fugitive Emissions:	Unintentional greenhouse gas emissions of unknown quantities from unknown locations. According to the Canadian Association of Petroleum Producers (CAPP) fugitive emissions include fugitive equipment leaks, accidents and equipment failures. Equipment may leak due to normal wear and tear, poor design or incorrect installation. Fugitive emissions may occur at any point during the extraction, processing, and

[5] CAPP. (2005). *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry, Volume 5, Compendium of Terminology, Data Sources, etc.*

transport of raw or processed oil and natural gas. Typical sources of equipment leaks include: threaded and flanged connections, valve stem packing leaks, leakage past valve seats to the atmosphere, compressor seals, pump seals, pressure regulator vents and sampling ports. Accidents and equipment failures include: spills, pipeline ruptures, gas migration and surface casing vent flows[6].

[6] ibid

2.0 Quantification Development and Justification

The following sections outline the quantification development and justification.

2.1 Identification of Sources and Sinks (SSs) for the Project

SSs were identified for the project by reviewing the seed document and relevant industry guidelines for calculating GHG emissions. This process confirmed that the SSs in the process flow diagrams covered the full scope of eligible project activities under the protocol.

Based on the process flow diagrams provided in **FIGURE 1.1**, the project SSs were organized into life cycle categories in **FIGURE 2.1**. Descriptions of each of the SSs and their classification as controlled, related or affected are provided in **TABLE 2.1.**

The definitions for classifying SSs, based on Guidance provided by Environment Canada, are as follows:

Controlled: The behaviour or operation of a controlled SS is under the direction and influence of a project proponent through financial, policy, management, or other instruments.

Related: A related SS has material and / or energy flows into, out of, or within a project but is not under the reasonable control of the project proponent.

Affected: An affected SS is influenced by the project activity through changes in market demand or supply for projects or services associated with the project.

FIGURE 2.1: Project Element Life Cycle Chart

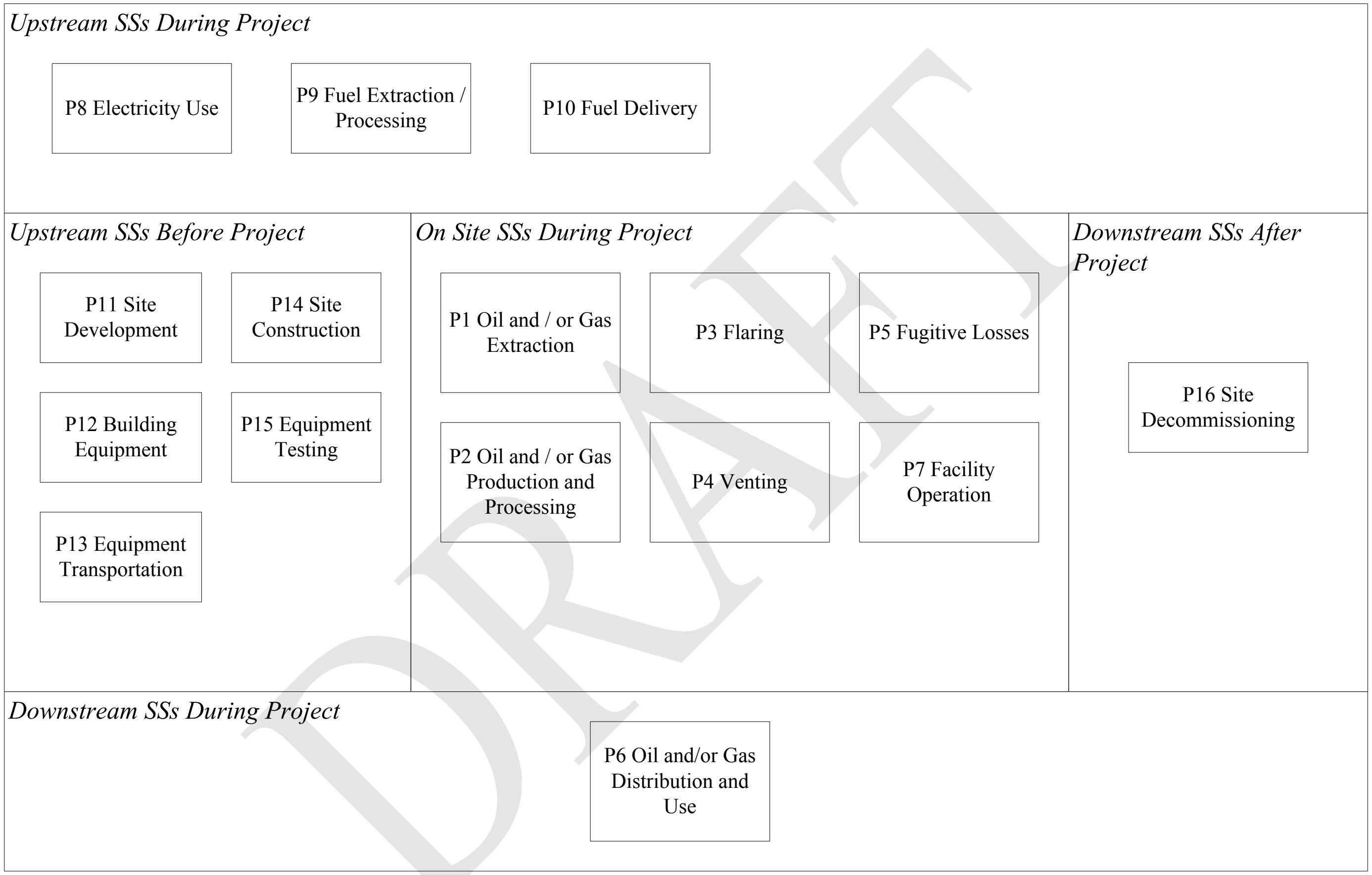


TABLE 2.1: Project SSs

1. SS	2. Description	3. Controlled, Related or Affected
Upstream SSs during Project Operation		
P8 Electricity Use	Electricity may be required to power equipment throughout the extraction, processing and transport processes. The quantity of power consumed and the source of electricity would need to be tracked.	Related
P9 Fuel Extraction and Processing	Each of the fuels used throughout the project may need to sourced and processed. This will allow for the calculation of the greenhouse gas emissions from the various processes involved in the production, refinement and storage of the fuels. The total volumes of fuel for each of the SSs are considered under this SS. Volumes and types of fuels are the important characteristics to be tracked.	Related
P10 Fuel Delivery	Each of the fuels used throughout the project may need to be transported to the site. This may include shipments by tanker or by pipeline, resulting in the emissions of greenhouse gases. It is reasonable to exclude fuel sourced by taking equipment to an existing commercial fuelling station as the fuel used to take the equipment to the sites is captured under other SSs and there is no other delivery.	Related
Onsite SSs during Project Operation		
P1 Oil and / or Gas Extraction	The extraction of oil and gas can be accomplished using various equipment and processes requiring fuel and electricity inputs. The emissions resulting from these inputs are captured under this SS. The quantity of power, fuel volume and fuel types would be tracked to determine equivalence with the baseline condition.	Controlled
P2 Oil and / or Gas Production and Processing	Operation of the oil/gas facility may require the use of mechanical equipment, pumps and pressure equipment. This may require several energy inputs such as electricity, natural gas and diesel. Quantities and types for each of the energy inputs would be tracked.	Controlled
P3 Flaring[7]	Flaring is a common means of disposing of waste gas at oil and gas facilities. Flaring is normally used at sour gas facilities where waste gas contains toxic components and for both high and low pressure waste gas streams. From time to time gas may be flared at the baseline site as a result of emergency shut-down, maintenance or other operational conditions. Emissions of greenhouse gases would be contributed from the combustion of the gases as well as from any fuel gas used in flaring to ensure more complete combustion. Quantities of gas being flared and the quantities of fuel gas would need to be tracked.	Controlled

[7] CAPP. (2005). *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry, Volume 5, Compendium of Terminology, Data Sources, etc.*

1. SS	2. Description	3. Controlled, Related or Affected
P4 Venting[8]	Venting is a common means of disposing of waste gas at oil and gas facilities and is defined as emissions to the atmosphere by design or operational practice, commonly from gas operated devices. Venting may occur either continuously or intermittently. The quantity of gas vented would need to be tracked. Reported venting includes the sum of all vented volumes stated in production accounting records and includes casing gas venting, waste associated gas flows, treater and stabilizer off-gas and gas volumes released during upset, depressurization or emergency events. Unreported Venting is defined as venting from processes or equipment that is not typically reported in production accounting data. Sources may include glycol dehydrator off-gas, loading/unloading losses, storage losses, pneumatic devices, etc. Note that emissions of vent gases will be accounted for under the SS P5 Fugitive Losses.	Controlled
P5 Fugitive Losses	Fugitive emissions will occur from equipment used at the project site. Sources of fugitive losses may include leaking fittings / seals, instrument venting, glycol dehydrators, vapour from oil batteries, non routine venting from equipment failure or pressure release and plant tank venting. The quantity and composition of fugitive emissions would need to be tracked.	Controlled
P6 Facility Operation	Typical facilities could include oil and / or gas production, processing, dehydration and transmission or other upstream oil and gas operations. The operations of the facility at the project site may require the combustion of fossil fuels, precipitating greenhouse gas emissions. Volumes and types of fuels are the important characteristics to be tracked.	Controlled
Downstream SSs during Project Operation		
P7 Fuel Production, Distribution and Usage	Oil, natural gas, coal bed methane and/or other petroleum products may be produced as a result of the project. The quantity of fossil fuels produced and transported for processing would need to be tracked.	Related
Other		

[8] CAPP. (2005). *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry, Volume 5, Compendium of Terminology, Data Sources, etc.*

1. SS	2. Description	3. Controlled, Related or Affected
P11 Site Development	The site may need to be developed. This could include civil infrastructure such as access to electricity, gas and water supply, as well as sewer etc. This may also include clearing, grading, building access roads, etc. There will also need to be some building of structures for the facility such as storage areas, storm water drainage, offices, vent stacks, firefighting water storage lagoons, etc., as well as structures to enclose, support and house the equipment. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to develop the site such as graders, backhoes, trenching machines, etc.	Related
P12 Building Equipment	Equipment may need to be built either on-site or off-site. This includes all of the components of the storage, handling, processing, combustion, air quality control, system control and safety systems. These may be sourced as pre-made standard equipment or custom built to specification. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment for the extraction of the raw materials, processing, fabricating and assembly.	Related
P13 Equipment Transportation	Equipment built off-site and the materials to build equipment on-site, will all need to be delivered to the site. Transportation may be completed by train, truck, by some combination, or even by courier. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels to power the equipment delivering the equipment to the site.	Related
P14 Site Construction	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
P15 Equipment Testing	Equipment may need to be tested to ensure that it is operational. This may result in running the equipment using test fuels or fossil fuels in order to ensure that the equipment runs properly. These activities will result in greenhouse gas emissions associated with the combustion of fossil fuels and the use of electricity.	Related
P16 Site Decommissioning	Once the facility is no longer operational, the site may need to be decommissioned. This may involve the disassembly of the equipment, demolition of on-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 site.	Related

2.2 Identification of Baseline

2.2.1 Identification and Assessment of Possible Baseline Scenarios

An assessment of potential baseline scenarios was conducted based on the recommended methodology from best practice guidance in the Alberta Offset Credit Project Guidance Document. Each baseline scenario contemplated the selection of a static or dynamic approach or both. **TABLE 2.2** provides a summary of the baselines considered.

TABLE 2.2 Assessment of Possible Baseline Scenarios

1. Baseline Options	2. Description	3. Static/ Dynamic	4. Accept or Reject and Justify
Historic Benchmark	Assessment of baseline scenario based on site specific venting and fugitive emissions, determined from historic data from the site prior to project implementation.	Static and Dynamic.	Accept. Methane emissions are metered over the entire project site using the technologies for which this protocol is applicable. While venting and unplanned fugitive emissions are often difficult to meter and metering is not common industry practice, this technology allows for the accurate quantification of these emissions through direct measurement, continuous monitoring and complete site coverage.
Performance Standard	Assessment of the baseline scenario based on the typical composition and quantity of fugitive gases vented equipment leaks, and other sources of methane emissions during natural gas extraction, processing and transmission activities.	Dynamic.	Reject. Detailed data on venting and other unplanned emissions of gases from each source would need to be obtained. This data may not accurately represent site emissions. Further, depending on the site this approach may lead to a significant over or under-estimate of emissions. This is especially true if the facility is already operating above industry standards prior to project implementation.
Comparison Based	Assessment of baseline GHG emissions from venting and other fugitive emission sources based on the quantity and composition of gases emitted from a control group representative of typical industry practice.	Dynamic.	Reject. This approach is not practical as it would be necessary to characterize average industry emissions from each source of emissions to represent the 'control' group. Generalizing emissions by defining control groups would be challenging given that emissions can vary significantly between sites with time and depending on the equipment and operations at each site.

1. Baseline Options	2. Description	3. Static/ Dynamic	4. Accept or Reject and Justify
Project Based	Assessment of baseline GHG emissions using a model to project the quantity and composition of gases emitted from venting and other fugitive emissions into the future.	Dynamic.	Reject. This approach would require data on the quantity and composition of gases released from each emission source. Given that this data is difficult to track and likely not commonly available, this approach is not applicable.
Other	Other quantification that may be available through the program authority.	Unknown.	Reject. Not Applicable at this time.

2.2.1 Selection of Baseline

The baseline condition for projects applying this protocol is defined as the operating conditions prior to the identification and reduction of planned and / or unplanned fugitive methane emissions ~~–~~ and following the implementation of a Direct Inspection and Maintenance (DI&M) program.~~with a deduction in baseline emissions based on the impact of regulations and the resulting annual rate of industry improvement~~. The baseline is project-specific but would be anticipated to include planned and unplanned emissions of methane from venting and fugitive losses at any point in the oil and gas extraction, processing and transportation processes.

The approach to quantifying the baseline will be a historic benchmark based on direct measurement of methane emissions before and after reduction measures are in place. The baseline scenario for this protocol is dynamic as the volume of fugitive emissions would be expected to change materially from project to project~~ as a function of the annual rate of industry improvement.~~.

Project proponents must provide a minimum of one month of virtually continuous monitoring data with complete site coverage prior to project implementation to define the baseline condition for the project. Monthly methane emission measurements should then be used to develop an annual baseline methane emissions profile for the facility. Note that ~~A~~a monitoring period of one month was selected to eliminate the incentive for project proponents to put off repairing methane leaks as a means to achieve a higher baseline emissions intensity. Acceptable measurement technologies provide virtually continuous monitoring of methane emissions over time rather than a snapshot of emissions, as would be provided by traditional and point source measurement technologies. Further, given that direct measurement and complete coverage of the site is required during this monitoring period a high level of accuracy is anticipated.

The timing of the ~~one month~~ baseline monitoring period in relation to overall facility maintenance should be recorded. It may be appropriate to conduct baseline monitoring at

Comment [KB3]: TBD. Work being conducted to determine an appropriate baseline monitoring period.

Comment [KB4]: TBD

the midpoint of a maintenance period (i.e. midway between plant turnarounds) to ensure baseline emissions provide an accurate reflection of the typical level of emissions from the facility[9]. Note that it may not be appropriate to conduct baseline monitoring at the end of a maintenance period, as this may provide an overestimate of baseline emissions.

The baseline must be measured while the facility is in compliance with all applicable regulations, and following implementing of a Direct Inspection and Maintenance (DI&M) leak detection and repair program that meets the requirements ofsuch as ERCB Directive 060. Note that this directive limits the venting of methane and requires that all facility's have a fully implemented Direct Inspection and Maintenance (DI&M) leak detection and repair program by January 1st, 2010.

~~Beginning on January 1st, 2010 measured baseline emissions must be discounted by an industry improvement factor to account for the impacts that would have been achieved by implementing a DI&M program at the facility. Application of this improvement factor~~ Measuring the baseline following the implementation of a DI&M program will ensure that facilities only generate credits for reducing facility methane emissions below the level that would be achieved based on regulatory requirements.~~, as evidenced by common the common rate of industry improvement. The improvement factor will be based on an reporting reductions in fugitive emissions from facilities throughout Alberta as a result of these programs. Further detail is provided in Appendix B.~~

Baseline emissions may need to be reviewed following any significant structural or process changes at the facility. These may include activities such as equipment decommissioning and installation of new equipment that would have been conducted under business as usual activities (i.e. old equipment being switched out), process adjustments to account for changes in facility throughput, source gas composition, etc., insourcing or outsourcing of operations, purchase or sale of significant emission sources, etc. If evaluation indicates that the change is material (i.e. greater than 5% of base year emissions) and would have occurred in the absence of the project, the baseline emission intensity should be modified to reflect these changes. Some additional measurement and monitoring may be required. Justification must be provided by the project proponent to explain any changes to the facility's baseline emissions.

The baseline condition is defined, including the relevant SSs and processes, as shown in **FIGURE 1.2**. More detail on each of these SSs is provided in Section 2.3, below.

2.3 Identification of SSs for the Baseline

Based on the process flow diagrams provided in **FIGURE 1.2**, the project SSs were organized into life cycle categories in **FIGURE 2.2**. Descriptions of each of the SSs and their classification as either 'controlled', 'related' or 'affected' is provided in **TABLE 2.3.**

[9] CAPP. (2003). *CH4 and VOC Emissions: Volume 4*.

FIGURE 2.2: Baseline Element Life Cycle Chart

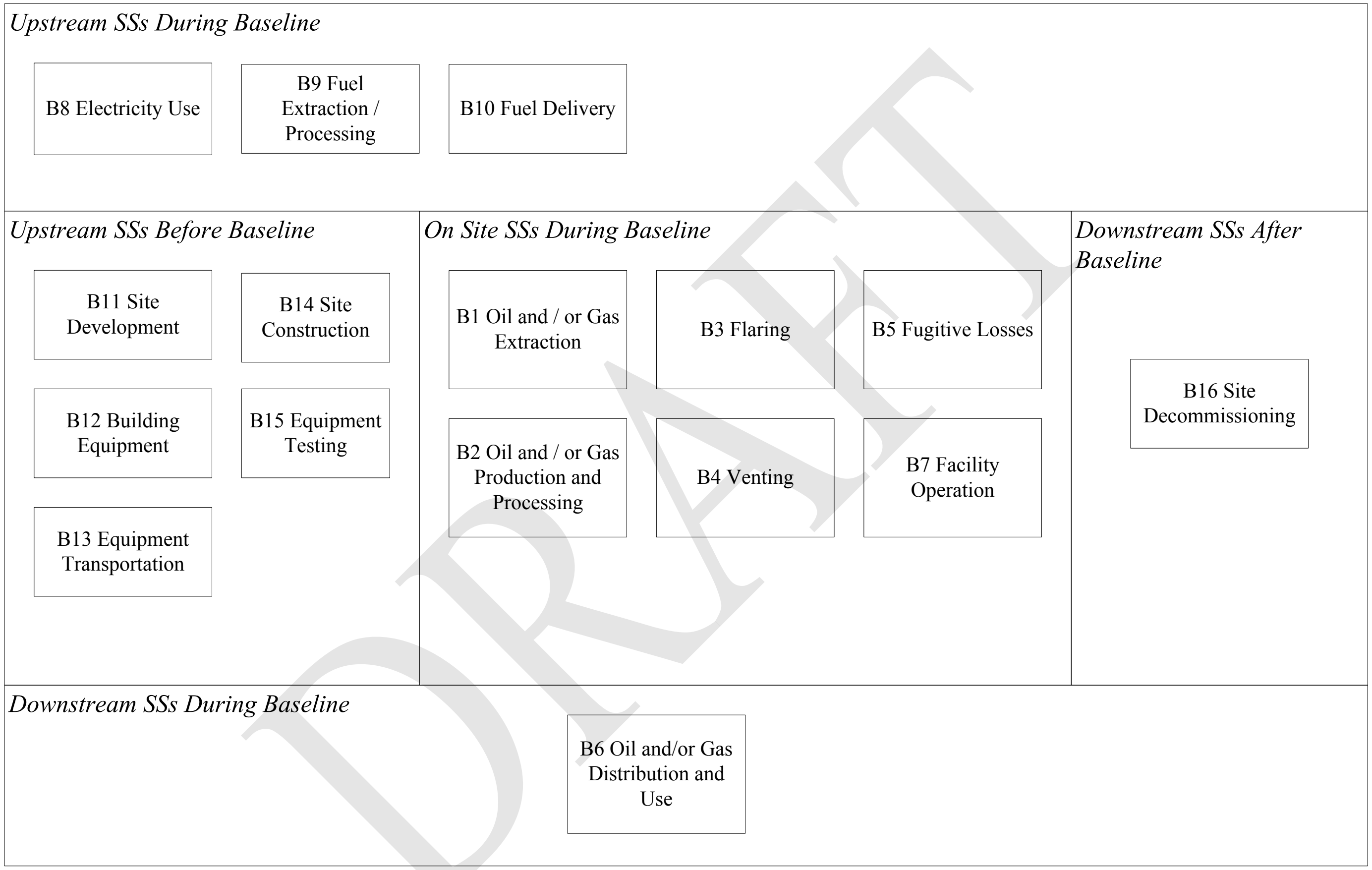


TABLE 2.3: Baseline SSs

1. SS	2. Description	3. Controlled, Related or Affected
Upstream SSs during Baseline Operation		
B8 Electricity Usage	Electricity may be required to power equipment throughout the extraction, processing and transport processes. The quantity of power consumed and the source of electricity would need to be tracked.	Related
B9 Fuel Extraction and Processing	Each of the fuels used throughout the baseline condition may need to sourced and processed. This will allow for the calculation of the greenhouse gas emissions from the various processes involved in the production, refinement and storage of the fuels. The total volumes of fuel for each of the SSs are considered under this SS. Volumes and types of fuels are the important characteristics to be tracked.	Related
B10 Fuel Delivery	Each of the fuels used throughout the baseline condition may need to be transported to the site. This may include shipments by tanker or by pipeline, resulting in the emissions of greenhouse gases. It is reasonable to exclude fuel sourced by taking equipment to an existing commercial fuelling station as the fuel used to take the equipment to the sites is captured under other SSs and there is no other delivery.	Related
Onsite SSs during Project Operation		
B1 Oil and / or Gas Extraction	The extraction of oil and gas can be accomplished using various equipment and processes requiring fuel and electricity inputs. The emissions resulting from these inputs are captured under this SS. The quantity of power, fuel volume and fuel types would be tracked to determine equivalence with the project condition.	Related
B2 Oil and / or Gas Production and Processing	Operation of the oil/gas facility may require the use of mechanical equipment, pumps and pressure equipment. This may require several energy inputs such as electricity, natural gas and diesel. Quantities and types for each of the energy inputs would be tracked.	Controlled
B3 Flaring[10]	Flaring is a common means of disposing of waste gas at oil and gas facilities. Flaring is normally used at sour gas facilities where waste gas contains toxic components and for both high and low pressure waste gas streams. From time to time gas may be flared at the baseline site as a result of emergency shut-down, maintenance or other operational conditions. Emissions of greenhouse gases would be contributed from the combustion of the gases as well as from any fuel gas used in flaring to ensure more complete combustion. Quantities of gas being flared and the quantities of fuel gas	Controlled

[10] CAPP. (2005). *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry, Volume 5, Compendium of Terminology, Data Sources, etc.*

1. SS	2. Description	3. Controlled, Related or Affected
	would need to be tracked.	
B4 Venting[11]	Venting is a common means of disposing of waste gas at oil and gas facilities and is defined as emissions to the atmosphere by design or operational practice, commonly from gas operated devices. Venting may occur either continuously or intermittently. The quantity of gas vented would need to be tracked. Reported venting includes the sum of all vented volumes stated in production accounting records and includes casing gas venting, waste associated gas flows, treater and stabilizer off-gas and gas volumes released during upset, depressurization or emergency events. Unreported Venting is defined as venting from processes or equipment that is not typically reported in production accounting data. Sources may include glycol dehydrator off-gas, loading/unloading losses, storage losses, pneumatic devices, etc. Note that emissions of vent gases will be accounted for under the SS B5 Fugitive Losses.	Controlled
B5 Fugitive Equipment Leaks	Fugitive emissions will occur from equipment used at the project site. Sources of fugitive losses may include leaking fittings / seals, instrument venting, glycol dehydrators, vapour from oil batteries, non routine venting from equipment failure or pressure release and plant tank venting. The quantity and composition of fugitive emissions would need to be tracked.	Controlled
B6 Facility Operation	Typical facilities could include oil and / or gas production, processing, dehydration and transmission or other upstream oil and gas operations. The operations of the facility at the project site may require the combustion of fossil fuels, precipitating greenhouse gas emissions. Volumes and types of fuels are the important characteristics to be tracked.	Controlled
Downstream SSs during Project Operation		
B7 Fuel Production, Distribution and Usage	Oil, natural gas, coal bed methane or other petroleum products would have to be produced to offset the additional production that which may occur under the project condition. The quantity of products produced and transported for processing would need to be tracked.	Related
Other		

[11] CAPP. (2005). *A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry, Volume 5, Compendium of Terminology, Data Sources, etc.*

1. SS	2. Description	3. Controlled, Related or Affected
B11 Site Development	The site may need to be developed. This could include civil infrastructure such as access to electricity, gas and water supply, as well as sewer etc. This may also include clearing, grading, building access roads, etc. There will also need to be some building of structures for the facility such as storage areas, storm water drainage, offices, vent stacks, firefighting water storage lagoons, etc., as well as structures to enclose, support and house the equipment. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to develop the site such as graders, backhoes, trenching machines, etc.	Related
B12 Building Equipment	Equipment may need to be built either on-site or off-site. This includes all of the components of the storage, handling, processing, combustion, air quality control, system control and safety systems. These may be sourced as pre-made standard equipment or custom built to specification. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment for the extraction of the raw materials, processing, fabricating and assembly.	Related
B13 Equipment Transportation	Equipment built off-site and the materials to build equipment on-site, will all need to be delivered to the site. Transportation may be completed by train, truck, by some combination, or even by courier. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels to power the equipment delivering the equipment to the site.	Related
B14 Site Construction	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
B15 Equipment Testing	Equipment may need to be tested to ensure that it is operational. This may result in running the equipment using test fuels or fossil fuels in order to ensure that the equipment runs properly. These activities will result in greenhouse gas emissions associated with the combustion of fossil fuels and the use of electricity.	Related
B16 Site Decommissioning	Once the facility is no longer operational, the site may need to be decommissioned. This may involve the disassembly of the equipment, demolition of on-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 site.	Related

2.4 Selection of Relevant Project and Baseline SSs

Each of the SSs from the project and baseline condition were compared and evaluated as to their relevancy using the guidance provided in Annex VI of the "Guide to Quantification Methodologies and Protocols: Draft", dated March 2006 (Environment Canada). The justification for the exclusion or conditions upon which SSs may be excluded is provided in **TABLE 2.4** below. All other SSs listed previously are included.

TABLE 2.4: Comparison of SSs

1. Identified SS	2. Baseline (C, R, A)	3. Project (C, R, A)	4. Include or Exclude from Quantification	5. Justification for Exclusion
Upstream SSs				
P8 Electricity Use	N/A	Related	Exclude	Excluded as these SSs are not relevant to the project as the emissions from these practises are covered under proposed greenhouse gas regulations.
B8 Electricity Use	Related	N/A	Exclude	
P9 Fuel Extraction and Processing	N/A	Related	Exclude	Excluded as this protocol is applicable to oil and gas production and processing facilities. These emissions are thereby accounted for in the other project and baseline SS's and including them would result in double counting.
B9 Fuel Extraction and Processing	Related	N/A	Exclude	
P10 Fuel Delivery	N/A	Related	Exclude	Excluded as the emissions from transportation are do not change between the project and baseline conditions, therefore this SS is not relevant for quantification.
B10 Fuel Delivery	Related	N/A	Exclude	
Onsite SSs				
P1 Oil and / or Gas Extraction	N/A	Related	Exclude	Excluded as the activity of oil and gas extraction is equivalent in the project and baseline conditions. The emissions do not change, therefore this SS is not relevant for quantification.
B1 Oil and / or Gas Extraction	Related	N/A	Exclude	
P2 Oil and / or Gas Production and Processing	N/A	Controlled	Exclude	Excluded as the activity of oil and gas production and processing is equivalent in the project and baseline conditions. The emissions do not change, therefore this SS is not relevant for quantification.
B2 Oil and / or Gas Production and Processing	Controlled	N/A	Exclude	
P3 Flaring	N/A	Controlled	Include	N/A (This SS may be excluded at facilities that sell methane as a final product as methane would not be flared. At facilities that do not sell methane (i.e. gas facility) flaring may be the only option and this SS is included).
B3 Flaring	Controlled	N/A	Include	N/A
P4 Venting	N/A	Controlled	Exclude	Excluded as the methane emissions from venting are included in the quantification of the SS P5 Fugitive Losses.

1. Identified SS	2. Baseline (C, R, A)	3. Project (C, R, A)	4. Include or Exclude from Quantification	5. Justification for Exclusion
B4 Venting	Controlled	N/A	Exclude	Excluded as the methane emissions from venting are included in the quantification of the SS B5 Fugitive Losses.
P5 Fugitive Losses	N/A	Controlled	Include	N/A
B5 Fugitive Losses	Controlled	N/A	Include	N/A
P6 Facility Operation	N/A	Controlled	Exclude	Excluded as the emissions from facility operation will either not be impacted by project implementation or decreased if captured methane is used as a fuel source on-site. Further, fuel consumption may vary as a function of seasonal variations, changes in the composition of gas processed at the facility and other factors that would not be reflected in the baseline or impacted by the project. This SS is therefore not relevant for quantification.
B6 Facility Operation	Controlled	N/A	Exclude	
Downstream SSs				
P7 Fuel Production, Distribution and Use	N/A	Related	Exclude	Excluded as these are likely equivalent under the project and baseline conditions.
B7 Fuel Production, Distribution and Use	Related	N/A	Exclude	
Other				
P11 Site Development	N/A	Related	Exclude	Emissions from site development are not material given the long project life, and the minimal site development typically required.
B11 Site Development	Related	N/A	Exclude	Emissions from site development are not material for the baseline condition given the minimal site development typically required.
P12 Building Equipment	N/A	Related	Exclude	Emissions from building equipment are not material given the long project life, and the minimal building equipment typically required.
B12 Building Equipment	Related	N/A	Exclude	Emissions from building equipment are not material for the baseline condition given the minimal building equipment typically required.

1. Identified SS	2. Baseline (C, R, A)	3. Project (C, R, A)	4. Include or Exclude from Quantification	5. Justification for Exclusion
P13 Equipment Transportation	N/A	Related	Exclude	Emissions from transportation of equipment are not material given the long project life, and the minimal transportation of equipment typically required.
B13 Equipment Transportation	Related	N/A	Exclude	Emissions from transportation of equipment are not material for the baseline condition given the minimal transportation of equipment typically required.
P14 Site Construction	N/A	Related	Exclude	Emissions from construction on site are not material given the long project life, and the minimal construction on site typically required.
B14 Site Construction	Related	N/A	Exclude	Emissions from construction on site are not material for the baseline condition given the minimal construction on site typically required.
P15 Equipment Testing	N/A	Related	Exclude	Emissions from testing of equipment are not material given the long project life, and the minimal testing of equipment typically required.
B15 Equipment Testing	Related	N/A	Exclude	Emissions from testing of equipment are not material for the baseline condition given the minimal testing of equipment typically required.
P16 Site Decommissioning	N/A	Related	Exclude	Emissions from decommissioning are not material given the long project life, and the minimal decommissioning typically required.
B16 Site Decommissioning	Related	N/A	Exclude	Emissions from decommissioning are not material for the baseline condition given the minimal decommissioning typically required.

2.5 Quantification of Reductions, Removals and Reversals of Relevant SS

2.5.1 Quantification Approaches

Quantification of the reductions, removals and reversals of relevant SSs for each of the greenhouse gases will be completed using the methodologies outlined in **TABLE 2.5**, below. These calculation methodologies serve to complete the following three equations for calculating the emission reductions from the comparison of the baseline and project conditions.

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

$$\text{Emissions}_{\text{Baseline}} = \text{Emissions}_{\text{Methane (Baseline)}}$$

$$\text{Emissions}_{\text{Project}} = \text{Emissions}_{\text{Flaring}} + \text{Emissions}_{\text{Methane (Project)}}$$

Where:

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

$\text{Emissions}_{\text{Methane (Baseline)}}$ = emissions under SS B4 Venting and SS B5 Fugitive Losses

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

$\text{Emissions}_{\text{Flaring}}$ = emissions under SS P3 Flaring

$\text{Emissions}_{\text{Methane (Project)}}$ = emissions under SS P4 Venting and SS P5 Fugitive Losses

TABLE 2.5: Quantification Procedures

1.0 Project/ Baseline SS	2. Parameter / Variable	3. Unit	4. Measured / Estimated	5. Method	6. Frequency	7. Justify measurement or estimation and frequency
Project SSs						
P3 Flaring	$Emissions_{Flaring} = (Emissions_{Methane\ (Baseline)} - Emissions_{Methane\ (Project)}) * (1 - Eff) * GWP_{CH4}$; $([(Emissions_{Methane\ (Baseline)} - Emissions_{Methane\ (Project)}) * Eff * EF_{CO2}] / \rho\ CH_4)$; $([(Emissions_{Methane\ (Baseline)} - Emissions_{Methane\ (Project)}) * Eff * EF_{N2O}] / \rho\ CH_4)$;					
	$Emissions_{Flaring}$	kg of CO_{2E}	N/A	N/A	N/A	Quantity being calculated. This equation assumes that any methane that was released in the baseline condition but conserved in the project condition at facilities that do not sell methane as a final product is flared. Note that in practice this ~~will~~ may not ~~generally~~ be the case, but it is conservative to assume that conserved gas is flared and emitted as CO_2. The project proponent also has the option of demonstrating that methane is not flared. This equation ~~also~~ assumes that no supplemental fuel gas (i.e.natural gas or sales gas that is added to the gas stream to be flared) is required to meet ERCB heating value requirements. ~~N_2O emissions are not calculated as they will likely not be material and there is limited sampling data available.~~ N_2O emissions are calculated using industrial emission factors for natural gas as this provides a conservative estimate of the emissions from flaring the captured methane gas stream.

	Total Baseline Methane Emissions / Emissions Methane (Baseline)	kg CH_4	N/A	Quantity calculated under SS B5	Monthly	The quantity of baseline methane emissions calculated for the SS B5. The difference between project and baseline emissions from the SS's B5 and P5 represents the quantity of methane conserved in the project condition.
	Total Project Methane Emissions / Emissions Methane (Baseline)	kg CH_4	N/A	Quantity calculated under SS P5	Monthly	The quantity of baseline methane emissions calculated for the SS B5. The difference between project and baseline emissions from the SS's B5 and P5 represents the quantity of methane conserved in the project condition.
	Flare Efficiency / Eff	%	Estimated	From the Canadian Association of Petroleum Producers (CAPP) reference documents flare efficiency is 98%. This value is in accordance with current regulations in Alberta ERCB Directive 060.	Annual	Reference values adjusted periodically.
	Density of Methane / ρ CH_4	kg / m^3	Constant	0.~~678~~ 717 kg/m^3 at standard temperature and pressure (STP). ~~15°C and 101.3kPa, the standard reference conditions used by the natural gas industry.~~	Reference Value	Density should be corrected if actual temperatures and pressures of the gas stream are not consistent with reference values.
	EF_{CO2}	kg CO_2 / m^3 methane	Estimated	From Environment Canada / the Canadian Association of Petroleum Producers (CAPP) (Appendix B). ~~1.86 kg $_{CO2}$ per m^3 fuel burned. Calculated using equation provided by CAPP for calculating emissions from raw gas flaring and a fuel composition of 100% methane.~~	N/A	Emission factors for natural gas is used to estimate the N_2O emissions from combusting the methane gas stream. This approach is consistent with the Alberta Quantification Protocol for Landfill Gas Capture and Combustion. Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.

	EF_{N2O}	kg N_2O / m^3 methane	Estimated	From Environment Canada / the Canadian Association of Petroleum Producers (Appendix B).	Annual	Emission factors for natural gas is used to estimate the N_2O emissions from combusting the methane gas stream. This approach is consistent with the Alberta Quantification Protocol for Landfill Gas Capture and Combustion. Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
P4 Venting P5 Fugitive Losses	*This equation (1) will be used to quantify baseline methane emissions for leaking equipment / processes and venting that is detected and quantified using one of the technologies described in Appendix A.* 1. $Emissions_{Methane\ (Project)} = \sum(Measured\ Leak\ Vol._{Methane\ i} * \rho_{CH4} * GWP_{CH4})$ *This equation (2) will be used to quantify baseline methane emissions for leaking equipment / processes and venting that is detected using one of the technologies described in Appendix A and quantified by measuring the flow rate using a direct measurement technique (i.e. in-line flow meter, bagging, hi-flow sampler, isolation flux chamber, etc.).* 2. $Emissions_{Methane\ (Project)} = \sum(Q_{Leak\ i} * \%CH_4 * Project\ Hrs_i * \rho_{CH4} * GWP_{CH4})$					
	$Emissions_{Methane\ (Project)}$	kg of CO_{2E}	N/A	N/A	N/A	Quantity being calculated. Project emissions will be measured and monitored continuously using direct measurement and complete site coverage for a period of ## months for each year of the crediting period. Monthly methane emission measurements should then be used to develop an annual methane emissions profile for the facility.
	One of the following two variables (numbered 1 and 2) may be measured at the facility. The methodology selected will depend on the type of leak or available technology.					
	1. Measured Volume of Methane Emissions / Measured Leak $Vol._{Methane}$	m^3	Measured	Direct measurement of volume of methane emitted ~~until the leak is fixed~~, converted to STP conditions.	Direct measurement using one of the methodologies listed in Appendix A, or other similar technology. Monthly reconciliation of measured data.	Direct measurement and continuous monitoring represent industry best practice. Frequency of measurement is highest level possible.

Comment [KB5]: TBD.

	2. Flow Rate of Each Type of Equipment Leak / $Q_{Leak\ i}$	m^3 / hr	Measured	Direct measurement of flow rate of gas of leaking component using a bag and stopwatch, rotameter, hi-volume, hi-flow sampler or other appropriate measurement technique.	Following detection using one of the methodologies listed in Appendix A or other similar technology. Flow rate will be assessed on a per emission source / leak basis.	Direct measurement represents industry best practice. The flow rate of the leaking component will be measured prior to fixing the leak. Note that similar equipment / processes may be aggregated. The project proponent should be prepared to provide justification to demonstrate that this is appropriate.
	CH_4 Composition in Gas Stream (Volumetric Basis) / % CH_4	%	Measured	Direct measurement of the percent methane composition by volume of the gas stream.	Quarterly	Direct measurement represents industry best practice. Composition may vary throughout the project. Quarterly gas composition measurement is reasonable for operation of an oil and gas facility
	Hours Operational during Project Monitoring Period / Project Hrs_i	Hrs	Measured	Measurement of the duration of time the unit or process has been operating.	Monthly	The number of hours the unit or process has been operational will be used to assess the project emissions from the process or component.
	Density of CH_4 / ρ_{CH4}	kg / m^3	Constant	717 kg/m^3 at standard temperature and pressure (STP).~~0.678 kg/m^3 at 15°C and 101.3kPa, the standard reference conditions used by the natural gas industry.~~	Reference Value	N/A
Baseline SSs						
B4 Venting B5 Fugitive Losses	*This equation (1) will be used to quantify baseline methane emissions for leaking equipment / processes and venting that is detected and quantified using one of the technologies described in Appendix A.* 1. $Emissions_{Methane\ (Baseline)} = \sum([Measured\ Vol._{Methane\ i} * \rho_{CH4} * Project\ Hrs_i * \sout{(1 - Industry_{Improvement})}] / Baseline\ Hrs_i) * GWP_{CH4}$ *This equation (2) will be used to quantify baseline methane emissions for leaking equipment / processes and venting that is detected using one of the technologies described in Appendix A and quantified by measuring the <u>flow rate</u> using a point source (or other appropriate) measurement*					

	technique. 2. Emissions $_{Methane\ (Baseline)}$ = ∑ ($Q_{Leak\ i}$ * %CH_4 * Project Hrs_i * ρ_{CH4}) ~~* (1 – Industry $_{Improvement}$)~~ * GWP_{CH4}					
	Emissions $_{Methane\ (Baseline)}$	kg of CO_{2E}	N/A	N/A	N/A	Quantity being calculated as discussed below. Baseline emissions will be measured and monitored continuously using direct measurement and complete site coverage for a period of ## months prior to project implementation and following the implementation of a DI&M program that meets the requirements of ERCB Directive 060. Monthly methane emission measurements should then be used to develop an annual baseline methane emissions profile for the facility.
	One of the following two variables (numbered 1 and 2) may be measured at the facility. The methodology selected may depend on the type of leak or available technology.					
	1. Total Volume of Methane Emissions / Measured Vol. $_{Methane}$	m^3	Measured	Direct measurement of volume of methane being emitted over a one month period, converted to STP conditions.	Direct measurement using one of the methodologies listed in Appendix A, or other similar technology. Monthly reconciliation of measured data.	Direct measurement and continuous monitoring represent industry best practice. Frequency of measurement is highest level possible.
	2. Flow Rate of Each Type of Equipment Leak / $Q_{Leak\ i}$	m^3 / hr	Measured	Direct measurement of flow rate of gas of leaking component using a bag and stopwatch, rotameter, hi-volume, hi-flow sampler or other appropriate measurement technique.	Following detection using one of the methodologies listed in Appendix A or other similar technology. Flow rate will be assessed on a per emission source / leak basis.	Direct measurement represents industry best practice. The flow rate of the leaking component will be measured prior to fixing the leak. Note that equipment / processes may be aggregated if applicable. The project proponent should be prepared to provide justification to demonstrate that this approach is appropriate.

Comment [KB6]: TBD.

	CH_4 Composition in Gas Stream (Volumetric Basis) / % CH_4	%	Measured	Direct measurement of the percent methane composition by volume of the gas stream.	Quarterly	Direct measurement represents industry best practice. Composition may vary throughout the project. Quarterly gas composition measurement is reasonable for operation of an oil and gas facility
	Hours Operational during Project Monitoring Period / Project Hrs $_i$	Hrs	Measured	Measurement or reasonable approximation of the hours the unit or process has been operational in the project condition.	Monthly	The number of hours the unit or process has been operational will be used to assess the monthly methane emissions from the leaking component.
	Hours Operational during Baseline Monitoring Period / Baseline Hrs $_i$	Hrs	Measured	Measurement or reasonable approximation of the hours the unit or process has been operational in the baseline monitoring period.	Monthly	The number of hours the unit or process was operational during the baseline monitoring period will be used to assess the monthly methane emissions from the leaking component.
	Density of CH_4 / ρ_{CH4}	kg / m^3	Constant	717 kg/m^3 at standard temperature and pressure (STP).~~0.678 kg/m^3 at 15°C and 101.3kPa, the standard reference conditions used by the natural gas industry.~~	Reference Value	N/A
Multiple Project and Baseline SSs	Global Warming Potential of Methane / GWP_{CH4}	kg CO_{2E} / kg CH_4	Estimated	From Environment Canada; IPCC.	Annual	The applicable global warming potential of CH_4 is 21, as per the Intergovernmental Panel on Climate Change. *Climate Change 1995: The Science of Climate Change* (Cambridge, UK: Cambridge University Press, 1996). This value should be used for all calculations, to maintain consistency with internationally accepted best practice guidance.

2.5.2 Contingent Data Approaches

Contingent means for calculating or estimating the required data for the equations outlined in section 2.5.1 are summarized in **TABLE 2.6**, below.

2.6 Management of Data Quality

In general, data quality management must include sufficient data capture such that the mass and energy balances may be easily performed with the need for minimal assumptions and use of contingency procedures. The data should be of sufficient quality to fulfill the quantification requirements and be substantiated by company records for the purpose of verification.

The project proponent shall establish and apply quality management procedures to manage data and information. Written procedures should be established for each measurement task outlining responsibility, timing and record location requirements. The greater the rigour of the management system for the data, the more easily an audit will be to conduct for the project.

2.6.1 Record Keeping

Record keeping practises should include:

a. Electronic recording of values of logged primary parameters for each measurement interval;
b. Printing of monthly back-up hard copies of all logged data;
c. Written logs of operations and maintenance of the project system including notation of all shut-downs, start-ups and process adjustments;
d. Retention of copies of logs and all logged data for a period of 7 years; and
e. Keeping all records available for review by a verification body.

2.6.2 Quality Assurance/Quality Control (QA/QC)

QA/QC should be applied to the changes made at the facility resulting in reduced methane emissions. These include, but are not limited to:

a. Recording all changes made at the facility that may reduce methane emissions including process changes, installation of new equipment, implementation of different practices at the facility, equipment operation and maintenance activities, repairs, etc.; and
b. Listing of each change with as much detail as possible including date, location, cost, estimated emission reduction, etc.

QA/QC may need to be applied to the remote sensing technology depending on the technology selected to quantify facility methane emissions. These may include, but are not limited to[12]:

a. Calibration and checking of equipment according to manufacturer specifications;
b. Collection of sample that is representative in terms of time, location and conditions;
c. Collection of detailed meteorology observations concurrent with air measurements;
d. Period checks to ensure there is no interference from other nearby sources;
e. Review of air monitoring instrumentation to ensure detection limits are appropriate and equipment is rated to operate in cold weather;
f. Testing of equipment during precipitation or fog to ensure instrument performance is adequate; and
g. Collection of additional measurements and data for non-homogeneous sources. This will include the use of tracer to pollutant ratio testing to calibrate the dispersion model.

QA/QC can also be applied to add confidence that all measurements and calculations have been made correctly. These include, but are not limited to:

a Protecting monitoring equipment (sealed meters and data loggers);
b Protecting records of monitored data (hard copy and electronic storage);
c Checking data integrity on a regular and periodic basis (manual assessment, comparing redundant metered data, and detection of outstanding data/records);
d Comparing current estimates with previous estimates as a 'reality check';
e Provide sufficient training to operators to perform maintenance and calibration of monitoring devices;
f Establish minimum experience and requirements for operators in charge of project and monitoring; and
g Performing recalculations to make sure no mathematical errors have been made.

[12] CAPP. (1999). CH_4 and VOC Emissions from the Canadian Upstream Oil and Gas Industry – Volume 4

TABLE 2.6: Contingent Data Collection Procedures

1. Project/ Baseline SS	2. Parameter / Variable	3. Unit	4. Measured / Estimated	5. Method	6. Frequency	7. Justify measurement or estimation and frequency
Project SSs						
P3 Flaring	Total Baseline Methane Emissions / Emissions$_{Methane\ (Baseline)}$	None				
	Total Project Methane Emissions / Emissions$_{Methane\ (Baseline)}$	None				
P4 Venting P5 Fugitive Losses	Flow Rate of Each Type of Equipment Leak / Q$_{Leak\ i}$	None				
	Measured Volume of Methane Emissions / Measured Leak Vol.$_{Methane}$	None				
	CH_4 Composition in Gas Stream (Volumetric Basis) / % CH_4	%	Estimated	Interpolation of previous and following measurements taken.	Quarterly	Gas composition should remain relatively stable during steady-state operation. Interpolating gas composition provides a reasonable estimate when the more accurate and precise method cannot be used.
	Hours Operational or Leaking during Project Condition / Project Hrs$_i$	hrs	Estimated	Interpolation of previous and following measurements taken.	Monthly	Provides a reasonable estimate of the parameter when the more accurate and precise method cannot be used.
Baseline SSs						
B4 Venting B5 Fugitive	Flow Rate of Each Type of Equipment Leak / Q$_{Leak\ i}$	None				

1. Project/ Baseline SS	2. Parameter / Variable	3. Unit	4. Measured / Estimated	5. Method	6. Frequency	7. Justify measurement or estimation and frequency
Losses	Total Volume of Methane Emissions / Measured Vol. $_{Methane}$	None				
	CH_4 Composition in Gas Stream (Volumetric Basis) / % CH_4	%	Estimated	Interpolation of previous and following measurements taken.	Quarterly	Gas composition should remain relatively stable during steady-state operation. Interpolating gas composition provides a reasonable estimate when the more accurate and precise method cannot be used.
	Hours Operational in the Project Condition / Project Hrs $_i$	hrs	Estimated	Interpolation of previous and following measurements taken.	Monthly	Provides a reasonable estimate of the parameter when the more accurate and precise method cannot be used.
	Hours Operational during the Baseline Monitoring Period / Baseline Hrs $_i$	None				

Appendix A
Methods of Direct Measurement of Methane Emissions

Remote monitoring systems sensitive to methane may be used to quantify the methane emissions at a given facility using this protocol. Remote monitoring systems may employ either point or path-integrated sampling[13]. A range of point source and path-integrated methods of measurement of fugitive emissions were considered as summarized in the Technical Seed Document that accompanies this protocol.

According to the Technical Seed Document, traditional point source measurement techniques do not provide complete and continuous coverage of the site. As such, these technologies are not appropriate. Table A.1 contains a summary of available technologies. Only those technologies that provide direct quantification, virtually continuous monitoring and complete coverage are eligible. For further detail on the technologies outlined in **TABLE A.1** refer to the Petroleum Alliance of Canada's *Review and Update of Methods for Air Emissions Leak Detection and Quantification.* This document is available at: http://www.ptac.org/eet/dl/eetp0701.pdf.

The technology selected should be calibrated and checked at the site as required by manufacturer specifications to ensure accuracy.

Table A.1 Summary of Available Technologies

Technology	Direct Quantification	Virtually Continuous	Complete Coverage
7.0 POINT SOURCE LEAK DETECTION AND CONCENTRATION MEASUREMENT METHODS.			
7.1 CLOSE RANGE DETECTION AND MEASUREMENT METHODS.			
7.1.1 Flame Ionization Detection (FID).	Yes (in combination)	No	No
7.1.2 Photoionization Detection (PID).	Yes (in combination)	No	No
7.1.3 Catalytic Combustion (CC).	Yes (in combination)	No	No
7.1.4 Thermal Conductivity (TC).	Yes (in combination)	No	No
7.1.5 Solid State (SS).	Yes (in combination)	No	No
7.1.6 Infrared Absorption (IR).	Yes (in combination)	No	No
7.1.7 Tunable Diode Laser Absorption Spectroscopy (TDLAS).	Yes (in combination)	No	No
7.1.8 Bubble Tests.	No	No	No
7.1.9 Acoustic Leak Detection.	No	No	No
7.2 REMOTE SENSING METHODS.			
7.2.1 Passive IR Gas Imaging.	No	No	No
7.2.1.1 Thermal Imaging.	No	No	No
7.2.1.2 Image Multi – Spectral Sensing (IMSS).	No	No	No
7.2.2 Open Path Gas Detection from Point Sources.	No	No	No
7.2.2.1 Open Path Tunable Diode Laser Absorption Spectroscopy (TDLAS).	No	No	No
7.3 AIRBORNE SENSING METHODS (PIPELINE INSPECTIONS).			
7.3.1 Tunable Diode Laser Absorption Spectroscopy (TDLAS).	No	No	No
7.3.2 Airborne Differential Absorption LIDAR (Airborne DIAL).	No	No	No
7.3.3 Gas Filter Correlation Radiometry (GFCR).	No	No	No
8.0 POINT SOURCE QUANTIFICATION METHODS.			
8.1 BAGGING.	Yes	No	No
8.2 HI–FLOW SAMPLER.	Yes	No	No
8.3 ROTAMETERS AND OTHER FLOW METERING DEVICES.	Yes	No	No
8.4 TRACER GAS.	No	No	No
9.0 AREA SOURCE LEAK DETECTION AND QUANTIFICATION TECHNOLOGIES.			
9.1 DIFFERENTIAL ABSORPTION LIDAR (DIAL).	Yes	No	Yes
9.2 AIR DETECTION AND RANGING (AIRDAR).	Yes	Yes	Yes
9.3 OPEN PATH, PATH-INTEGRATED OPTICAL REMOTE SENSING (PI-ORS).	No	Yes	Yes
9.3.1 Open Path Tunable Diode Laser Absorption Spectroscopy (TDLAS).	* Yes	Yes	Yes
9.3.2 Open Path Fourier Transform Infrared (FTIR) Spectroscopy.	No	Yes	Yes
9.3.3 Radial Plume Mapping (RPM).	No	Yes	Yes

* Recently added quantification capability

* Table 1 from the Technical Seed Document (2008) completed by Keyera, Husky, Shell and Nexen

[13] CAPP. (1999). CH_4 and VOC Emissions from the Canadian Upstream Oil and Gas Industry – Volume 4

The following in-situ methods of quantification meet the requirements for direct, virtually continuous measurement with complete coverage as outlined in the accompanying Technical Seed Document. Note that other technologies that provide the same level of coverage and accuracy in estimates of emissions may also be applied.

Generally, if the emission source is homogeneous the use of remote sensing data is sufficient to accurately model the emission rate. For heterogeneous sources, additional testing and measurement may be required to determine the size, location and emission rate[14]. The project proponent should refer to CAPP's (1999) publication entitled: *CH_4 and VOC Emissions from the Canadian Upstream Oil and Gas Industry – Volume 4* for further guidance.

1. Air Detection and Ranging (AIRDAR)

This technology is able to measure fugitive emissions for the overall facility as well as the location and characteristics of important leaks[15]. AIRDAR is a proprietary technology that locates and quantifies emission sources based on concentrations of methane and wind measurements taken at various points around a facility. Emission plumes are intercepted with these point observations and characterised with AIRDAR's proprietarily algorithms that provide source locations and strengths. Variations in emission rates over time are also provided.

This method provides an estimate of fugitive source locations and volumes based on direct measurement at specific points, and can provide emission rates over time. The AIRDAR method is accessible to project proponents and could be used to provide a site-specific baseline as well as direct measurement of fugitive emissions under the project condition.

The AIRDAR technology is capable of tracking plumes of very low concentrations and is currently readily available in Alberta.

2. Open-Path Tunable Diode Laser Absorption Spectroscopy (TDLAS)[16]

Tunable Diode Laser Absorption Spectroscopy (TDLAS) is a type of open path gas detection that is used to identify and quantify airborne pollutants. Open path technologies are sensitive to low concentrations and high volumes of hydrocarbons, CH_4, H_2S and other gases. PTAC recommends that these technologies always be used in conjunction with point specific gas monitors to accurately assess the volume and concentration of gases.

[14] CAPP. (1999). CH_4 and VOC Emissions from the Canadian Upstream Oil and Gas Industry – Volume 4

[15] Petroleum Technology Alliance Canada Technology for Emission Reduction and Eco-Efficiency(TEREE) Steering Committee. (2007). *Review and Update of Methods Used for Air Emissions Leak Detection and Quantification*.

[16] Petroleum Technology Alliance Canada Technology for Emission Reduction and Eco-Efficiency(TEREE) Steering Committee. (2007). *Review and Update of Methods Used for Air Emissions Leak Detection and Quantification*.

The TDLAS technology involves the use of a laser diode and infrared absorption spectroscopy to scan the absorption line of a target gas. A photodiode detector measures the fraction of light absorption caused by the target gas molecules between the detector and a target or passive reflector, which is then used to calculate the gas's concentration.

The TDLAS technology is the most interference free method of any analytical method currently available for air emissions monitoring and leak detection and is not affected by water vapour or CO_2. The laser light is selective to detecting methane and has a measurement path of up to one kilometre. Further, it has very low detection limits and the system is self calibrating. Note that under heavy dust, steam or fog conditions the TDLAS system may be subject to error.

~~Appendix B~~Appendix B
~~Industry Improvement Factor~~
Relevant Emission Factors

In this protocol the facility's baseline methane emissions are discounted by an industry improvement factor to ensure that the project is incremental to standard industry practice and regulations. Application of this improvement factor will ensure that facilities only generate credits for reducing facility methane emissions below the level that would be achieved based on regulatory requirements, as evidenced by the rate of industry improvement.

This factor will be applied from January 1st, 2010 onwards as this is the date by which facilities must have a fully implemented DI&M program. This factor accounts for the reduction in methane emissions that would be realized in the absence of the project through implementing an industry standard DI&M program at the facility.

All values interpreted from volume 1 of the technical report: A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC) and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry dated September 2004 completed by Clearstone Engineering Ltd. on behalf of the Canadian Association of Petroleum Producers (CAPP).

Table B2: Emission Intensity of Combustion

Natural Gas		
Industrial		
Emissions Factor (CO_2)	1.891	kg CO_2 per m^3
Emissions Factor (CH_4)	0.00049	kg CH_4 per m^3
Emissions Factor (N_2O)	0.000049	kg N_2O per m^3
Producer Consumption		
Emissions Factor (CO_2)	2.389	kg CO_2 per m^3
Emissions Factor (CH_4)	0.0065	kg CH_4 per m^3
Emissions Factor (N_2O)	0.00006	kg N_2O per m^3