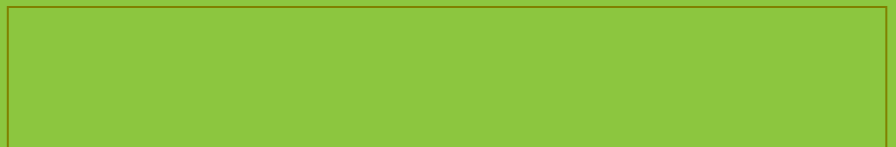


QUANTIFICATION PROTOCOL FOR DIRECT REDUCTIONS IN GREENHOUSE GAS EMISSIONS ARISING FROM FUEL SWITCHING FUEL IN MOBILE EQUIPMENT

Draft for Review

December 2011



Disclaimer:

The information provided in this document is intended as guidance only and is subject to periodic revisions. This document is not a substitute for the law. Please consult the *Specified Gas Emitters Regulation* and applicable legislation for all purposes of interpreting and applying the law. In the event that there is a discrepancy between this document and the *Specified Gas Emitters Regulation* or other legislation, the *Specified Gas Emitters Regulation* and other legislation prevail.

All Quantification Protocols approved under the *Specified Gas Emitters Regulation* are subject to periodic review as deemed necessary by the Department, and will be re-examined at a minimum of every 5 years from the original publication date to ensure methodologies and science continue to reflect best-available knowledge and best practices. Any updates to protocols occurring as a result of the 5-year and/or other reviews that are not due to legal requirements will apply at the end of the first credit duration period for applicable project extensions and for all new projects coming forward.

Where a project condition differs from approved government methodologies, or the project developer is unclear on protocol interpretation relative to their specific project, the project developer must contact Alberta Environment to discuss an appropriate interpretation and receive approval for any methodology changes prior to undertaking the project.

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

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Alberta Environment Related Publications

Climate Change and Emissions Management Act
Specified Gas Emitters Regulation
Specified Gas Reporting Regulation

Alberta's 2008 Climate Change Strategy

Technical Guidance for Completing Annual Compliance Reports
Technical Guidance for Completing Baseline Emissions Intensity Applications
Additional Guidance for Co-generation Facilities
Technical Guidance for Landfill Operators

Technical Guidance for Offset Project Developers
Technical Guidance for Offset Protocol Developers
Quantification Protocols (<http://environment.alberta.ca/02275.html>)

Others ???

DRAFT

1.0 Offset Project Description

This quantification protocol describes the process for quantifying greenhouse gas (GHG) emission reductions arising from reducing the GHG intensity of fuels consumed in powering mobile equipment, while maintaining an equal or greater level of service.

The opportunity for generating carbon credits with this protocol arises from the direct and indirect reductions of GHG emissions associated with the entire lifecycle of the baseline and project fuels. This includes direct emissions from combustion and indirect emissions related to fuel extraction, processing, and blending.

Replacement fuels include other fossil fuels, fossil fuel blends, or electricity. On a service provision basis, replacement fuels must demonstrate a lower GHG intensity compared to the displaced fuel. Services provided by mobile sources may include transportation of people or waste (e.g., transit buses or garbage collection fleets), transportation of cargo, and construction or other heavy equipment (e.g., forest harvesting).

Error! Reference source not found. shows a process flow diagram for the baseline and three potential project conditions for mobile sources.

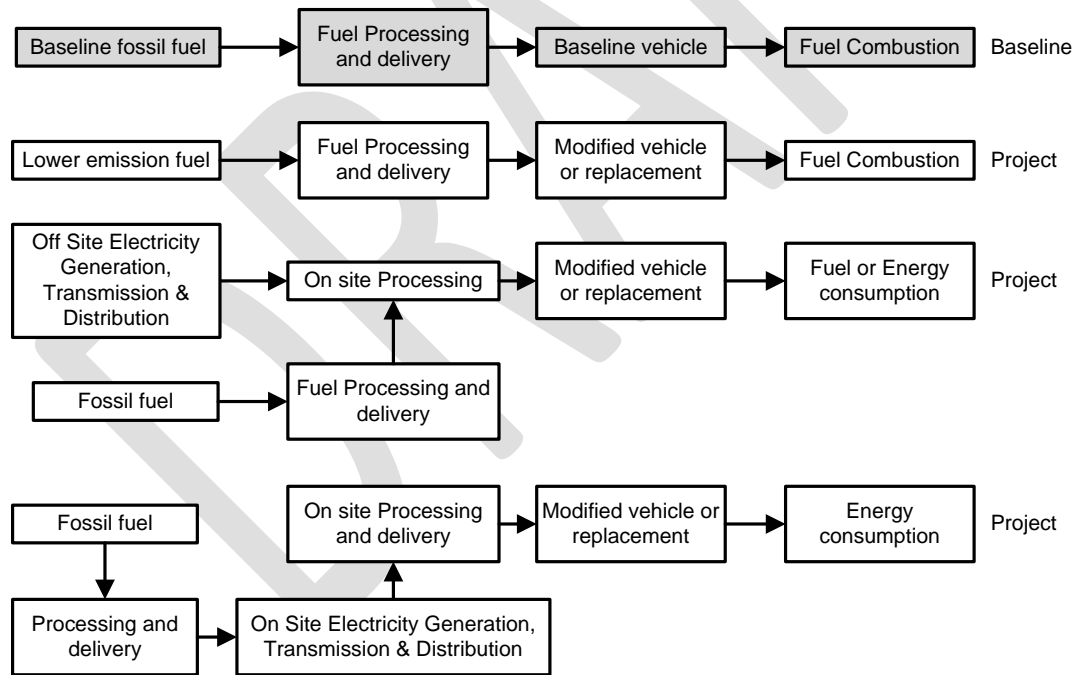


Figure 1: Generalized process flow for applicable baseline and project scenarios for mobile sources.

1.1 Protocol Scope

The methodology in this protocol applies to the quantification of both direct and indirect GHG emission reductions resulting from the use of less GHG-intensive fuels in mobile technologies.

The proposed protocol will include the flexibility to allow for replacement of existing technology or systems consuming fossil fuel or electricity with new technology or systems consuming lower emitting fuel or electricity. The protocol must be applied on a project-specific basis where a demonstrated lower lifecycle greenhouse gas intensity fuel is used.

For the purposes of this protocol, eligible fuel types would include but are not limited to:

- Natural gas including compressed or liquefied natural gas (CNG or LNG)
- Fossil fuel blends or use of dual fuel engines (e.g., Diesel and CNG)
- Electricity

Biogas, biomass, biofuels, and renewable fuels are explicitly excluded from the scope of this protocol as these are addressed by other Alberta Offset System protocols. The proposed protocol is stackable with other Alberta Offset System in the case of a project where excluded fuels are co-implemented with an eligible fuel under this protocol. Because the project condition uses measured fuel consumption to quantify emissions, co-implementation of this protocol is required with any other protocol that also uses measured fuel consumption. For example, the proposed transportation efficiency protocol (currently under development) must be co-implemented where the mode of transportation does not change (e.g., trucks, busses). Projects that do not rely on direct measure of fuel consumption, or where the mode of transportation changes (e.g., truck to rail, air to truck) are stackable with this protocol provided that the project boundaries are clearly established.

This protocol prescribes a static historic benchmark approach for determining the baseline condition. This ensures emission reductions account for an equal level of service between the baseline and the project condition. This also accommodates the emission reductions associated with a growth in service, where a lower GHG-intensive fuel is utilized in place of the higher intensive baseline fuel. Functional equivalence is achieved by using a common metric: units of carbon dioxide equivalent (CO₂e), or unit of fuel consumed per unit of service defined in the project. The units used in the baseline must be identical to the units used in the project (e.g., passenger km, tonnes km).

The baseline for mobile sources will incorporate applicable renewable fuel standards in place during the crediting period to ensure the intensity of the baseline fuel accurately reflects current standards.

At the time of publication of this protocol, the opportunity to reduce GHG emissions by displacing higher emitting fuels with lower emitting fuels has not been widely adopted. In Alberta, approximately 7.78 million tonnes CO₂e are emitted by heavy-duty diesel

vehicles for transport and related activities¹. The displacement of diesel with lower emitting fuels represents the largest potential opportunity for reducing emissions from this protocol.

Relevant greenhouse gas emissions for this protocol are shown in **Error! Reference source not found.**, and CO₂e emission factors are described in **Appendix C**

Table 1: Relevant Greenhouse Gases

Specified Gas	Formula	100-year GWP	Applicable to Project
Carbon Dioxide	CO ₂	1	Yes
Methane	CH ₄	21	Yes
Nitrous Oxide	N ₂ O	310	Yes
Sulphur Hexafluoride	SF ₆	23,900	No
Perfluorocarbons*	PFCs	Variable	No
Hydrofluorocarbons*	HFCs	Variable	No

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

1.2 Protocol Applicability

Project developers must be able to demonstrate the offset project meets the requirements of the Alberta Offset System, the Specified Gas Emitters Regulation, the quantification protocol, and related guidance documents. In particular, the project developer must provide sufficient evidence to demonstrate:

- Verifiable records on fuel use for each year where an offset will be claimed.
- Verifiable records for the service provided (e.g., passenger km, tonnes km) for each year where an offset will be claimed.
- Comparable records suitable for establishing baseline condition.

Additional eligibility criteria identified for use of this protocol:

1. Fuel must be consumed within Alberta. Where mobile emissions also occur outside Alberta, only the portion of fuel consumed within Alberta may be credited to the project or used to establish baseline.
2. Alternative fuel must have lower emission intensity when compared to the baseline fuel. Fuel comparison is based on service delivery and/or productivity (i.e., emissions per passenger km, emissions per tonnes km) equivalent.
3. When the project requires replacement of existing vehicles, the services provided to the project by the new vehicles must remain the same as measured in the baseline. Quantity of service may change with implementation of a project.

¹ (2009-2010 NIR report)

4. Must demonstrate that the most likely baseline scenario is continuation of use of higher carbon intensive fuel.
5. No regulation requiring change in baseline fuel use.

1.3 Protocol Flexibility

Four flexibility mechanisms are described for this protocol, as follows:

1. For projects where less than three years of historic data is available to justify the Baseline Condition, proponents may implement a statistical sampling alternative method described in *Appendix A*. This appendix provides example calculations including how the statistical sampling flexibility may be used.
2. For projects where no historic data is available to justify the Baseline Condition, proponents may implement a Performance Standard Baseline. *Appendix B* provides guidance on the method to defining a performance standard baseline. Approval from Alberta Environment must be requested prior to implementing this mechanism. The Proponent must be able to demonstrate a methodology and sufficient data to justify the Performance Standard baseline in conformance with the guidance provided in this document and by Alberta Environment.

The above two flexibility mechanisms cannot be applied where historical data exists, or where sufficient historical data may be collected prior to project initiation (e.g., baseline data may be collected after protect plan approval and before project initiation).

3. For project proponents that use onsite fuel processing (e.g., CNG, LNG refuelling stations), flexibility is provided to quantify upstream emissions for fuel extraction and processing of the feedstock separately from onsite fuel storage and dispensing.
4. More specific emission factors may be substituted for the generic emission factors indicated in this protocol document. The methodology for generation of these emission factors must ensure accuracy and conformance with the guidance provided in
5. **Appendix C.**

These flexibility mechanisms are provided to allow projects to proceed while maintaining conservativeness of the quantification and the integrity of the offsets quantified.

Use of any of these flexibility mechanisms must be clearly described in the project plan.

1.4 Glossary of Terms

1.4.1 Suggested protocol glossary terms

To add (Reviewers and Development team add to list here for terms you want in the glossary, or comment in the text and I will move them here):

1. Material change in emissions
2. Replacement fuel
3. Fossil fuel
4. Fossil fuel blend
5. Fugitive emission
6. Alberta Renewable Fuel standard (ARS)
7. Performance Standard Baseline
8. Historic Benchmark Baseline
9. Static Baseline
10. Dynamic Baseline
11. Functional Equivalence
12. Compressed Natural Gas
13. Liquid Natural Gas Products
14. Dual Fuel
15. Biofuel
16. Biogas
17. Biomass

From AENV (highlight those to delete)

Additionality: An action that results in greenhouse gas emission reductions that are beyond business as usual and supplemental to all regulatory requirements.

Alberta Emissions Offset Registry: A web-based platform that displays Alberta Offset Projects and tracks associated offset credits.

Alberta Environment: Regulator for the Specified Gas Emitters Regulation and Alberta Offset System.

Aggregated Projects: A collection of small projects using same quantification methodology that have been bundled to create a larger volume project for marketing, verification, and registration.

Baseline: A reference case against which the performance of the project is measured.

Biosequestration: The process of storing carbon dioxide in biological reservoirs including trees, plants, and soil biomass.

Biomass: Non-fossilized and biodegradable organic material originating from plants, animals and micro-organisms.

Business as Usual (BAU): Projection of normal operating conditions that would have occurred in the absence of incentives or regulatory changes.

Carbon Dioxide Equivalent (CO₂e): The 100-year global warming potential average of a unit of greenhouse gas (e.g. methane) compared to an equivalent unit of carbon dioxide (reference gas).

Climate Change and Emissions Management Act: Legislation in Alberta passed in 2002, allowing Alberta Environment to manage greenhouse gas emissions in the province.

Climate Change Central: An arms-length organization contracted primarily by Alberta Environment to support delivery of a variety of climate change programs including consumer incentive programs and supporting delivery of the Alberta Offset System.

Eligibility Criteria: Minimum requirements an offset project must meet to be eligible under the Alberta offset system.

Emission Factor: A representative value that can be used to estimate the rate or quantity of greenhouse gas emissions released to the atmosphere or removed through sequestration processes.

Emission Reduction: Occurs when emissions released into the atmosphere by a source are decreased or eliminated.

Emission Removal: Occurs when CO₂ or CO₂e is removed from the atmosphere through sequestration.

Global Warming Potential (GWP): Measures a greenhouse gas's relative warming effect on Earth's atmosphere compared with carbon dioxide expressed as a 100-year average.

Incremental: An eligibility criterion referring to a change in practice that results in additional emission reductions beyond business as usual.

Leakage: A shifting of greenhouse gas emissions outside a project boundary that is a result of the offset project.

Level of Assurance: Identifies the amount of work required to reach a stated level of comfort with an offset project.

Offset Credit: A tradable credit issued per tonne of greenhouse gas emissions reductions expressed as CO₂e.

Offset Project: An activity implemented by a project developer in accordance with a government-approved protocol that results in greenhouse gas emissions reductions or removals.

Project Developer: A person who implements an offset project in accordance with a government-approved protocol.

Project Start Date: An eligibility criterion referring to the date when the greenhouse gases are initially reduced or removed by the offset project.

Protocol Developer: Person or company responsible for coordinating the development of a quantification protocol.

Protocol Sponsor: Company or organization promoting the development of a quantification protocol for an identified reduction/removal opportunity.

Quantifiable: An eligibility criterion requiring that the emissions and reductions of greenhouse gases be calculated and monitored or estimated in accordance with the requirements set out in an approved quantification protocol appropriate to the project type.

Quantification Protocol: A government-approved methodology that outlines appropriate baseline conditions, eligible sources and sinks, and emission reduction calculations for a specific emission reduction activity.

Real: An eligibility criterion requiring that the offset project be a specific and identifiable action that results in a net greenhouse gas emission reduction or removal after leakage is taken into account.

Regulated Facility: A facility located in Alberta that emits over 100,000 tonnes CO₂e per year. The regulated facility may purchase offset credits for compliance under the Specified Gas Emitters Regulation.

Reversal: A release of carbon sequestered or stored in a reservoir back to the atmosphere.

Sequestration: The process of storing carbon in a reservoir to prevent its release into the atmosphere.

Scope: An eligibility criterion that refers to the Offset Project requirements stated in Section 7 of the Specified Gas Emitters Regulation.

Sink: Any process, activity or mechanism that removes greenhouse gases from the atmosphere.

Source: Any process or activity that releases greenhouse gases into the atmosphere.

Specified Gas Emitters Regulation: The regulation passed under the Climate Change and Emissions Management Act that enables the Alberta Offset System.

Validation: An optional process that is used to assess a project condition, including quantification methodologies, before the project is implemented.

Verifiable: An eligibility criterion requiring that a Third Party Verifier be able to confirm that the reductions or removals have been achieved as claimed.

Verification: An independent third party review of a project to assess project operating conditions against the baseline conditions to confirm the Offset Credits being claimed.

Third Party Verifier: A person or organization that meets the requirements of a third party auditor stated in Section 18 of the Specified Gas Emitters Regulation.

Unique: An eligibility criterion that requires that a greenhouse gas reduction or removal be used only once to create an offset credit.

2.0 Baseline Condition

The baseline condition is defined by the fuel or mix of fuels which were consumed in the condition prior to displacing these fuels with lower emitting alternatives. Fossil fuels are consumed to provide services including hauling of freight, passengers, or operation of heavy equipment. Specifically, project developers must be able to demonstrate the types of fuels consumed in the baseline and the level of service or productivity provided per unit of fuel consumed.

The proposed protocol requires that the baseline be established using measures of productivity per unit of fuel consumed. Productivity measures are then used to calculate baseline emissions based on the estimated volume of fuel required to provide the same level of service as the known (measured) project condition.

This protocol prescribes a **Static, Historic Benchmark** approach for determining the baseline condition. This ensures emission reductions account for an equal level of service between the baseline and the project condition. This also accommodates the emission reductions associated with a growth in service, where (a) lower GHG-intensive fuel(s)

is/are utilized in place of the higher intensive baseline fuel(s). Functional equivalence is achieved by using a common metric: units of carbon dioxide equivalent (CO₂e), or unit of fuel consumed per unit of service defined in the project. The units used in the baseline must be identical to the units used in the project (e.g., passenger km, tonnes km).

Assumptions made with the historic benchmark baseline approach include:

- A common metric for service or productivity between baseline and project conditions (e.g., tonnes km, passenger capacity km)
- Three years of historical baseline data
- Technological or regulatory changes in fuel and efficiency will be applied to the baseline, including:
 - Use of current emission factors and methodologies as described in **Appendix C**;
 - Adjustments for mandates which lower the GHG intensity of the baseline fuel(s), (i.e. Renewable Fuel Standards and Low-Carbon Fuel Standards, or similar regulatory program); and
 - Adjustments to emission factors for sector level technological changes in engine efficiency that occur during the credit project period.

For projects where the service has not been supported in the past (e.g., a town is establishing bus service or curb side garbage pickup for the first time), the historic benchmark baseline is not applicable. In this case a **Static, Performance Standard** approach can be used and is included as a flexibility mechanism.

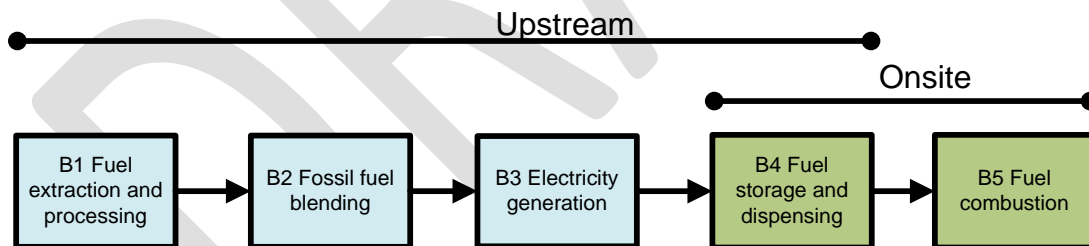


Figure 2: Process Flow Diagram for the Baseline Condition

Sources and sinks for each action are assessed based on guidance provided by Environment Canada and are classified as follows:

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

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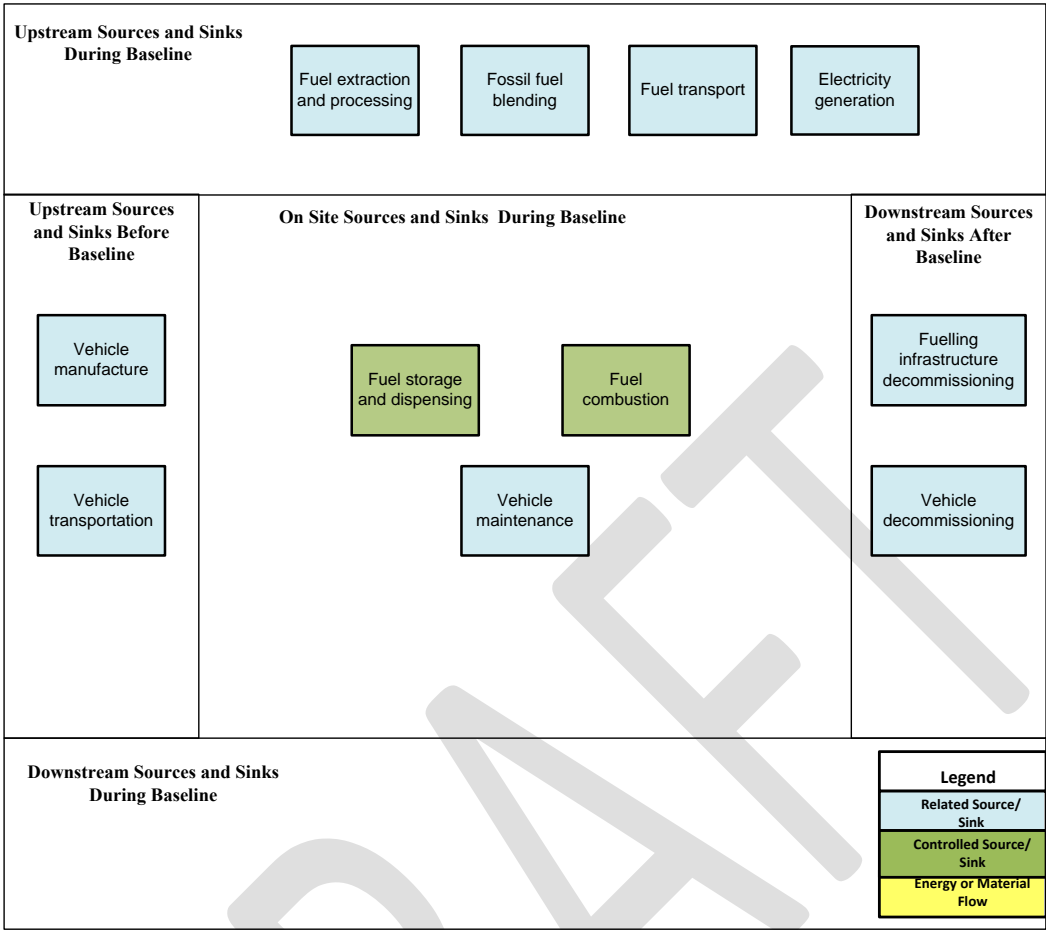


Figure 3: Baseline Sources and Sinks for the Fuel Switching in Mobile Equipment Protocol

Table 2: Baseline Sources and Sinks for the Fuel Switching Protocol.

Sources/Sinks	Description	Controlled, Affected, Related
<i>Upstream Sources and Sinks Before Project</i>		
Fuel extraction and processing	Energy is consumed during the extraction and production of fuels from crude oil or other feedstocks.	Related
Fossil fuel blending	Energy is consumed during the production of a blended fuel composed of two or more fossil fuels.	Related
Fuel transport	Transport of fossil fuel from the production facility to the end use location by pipeline, rail, or road. In addition to rail and or truck emissions, emission sources include energy required to pump, compress, or transfer fuel.	Related
Electricity Generation	In the case where electricity is a baseline fuel displaced by a lower-emitting fuel in the project, this electricity would have been generated by a mix of sources on the transmission grid or on-site.	Related
<i>Upstream Sources and Sinks During Project</i>		
Vehicle manufacture	Emissions associated with vehicle manufacturing. This includes emissions from assembly plant (electrical power, heating, cooling), materials used in manufacturing, lube oils (production and use) and transport of materials to the assembly facility.	Related
Vehicle transportation	Emissions related to the transportation of the vehicle from the point of manufacture to Alberta. Transportation may include ship, rail and road components.	Related
<i>Onsite Sources and Sinks During Project</i>		
Fuel storage and dispensing	Emissions for storage and dispensing may be from fuel consumed on site to provide the required energy or from electrical energy use. Depending on the fuel type, the energy to move (pump), compress, cool, or meter fuel as well as losses due to spills, evaporation, or other fugitive emissions may differ considerably between project and baseline conditions. This includes incremental changes in electrical energy use for different fuel types.	Controlled
Fuel combustion	Combustion of fuel during vehicle operation will result in a direct emission from the vehicle tailpipe.	Controlled
Vehicle maintenance	All activities associated with vehicle maintenance. This may include engine oil, lubricants, and replacement tires as well as maintenance facility power, heating and cooling emissions.	Affected
<i>Downstream Sources and Sinks After Project</i>		
Vehicle decommissioning	Vehicle decommissioning emission sources include demolition equipment, transport of vehicle to the decommissioning facility, transport and recycling of materials, transport and disposal of non recyclable material.	Related
Fuelling infrastructure decommissioning	Emissions sources for decommissioning of alternative fuelling infrastructure include demolition equipment, transport and recycling of materials, transport and disposal of non recyclable material, and site reclamation	Related

3.0 Project Condition

The project condition is defined by the emissions associated with the use of fuel(s) with lower life-cycle GHG emissions intensities in comparison to the fuel or fuel mixes previously consumed under the baseline condition.

Fuel use and levels of service during the Project are measured directly, and then compared to an amount of fuel that would have been consumed under baseline conditions to provide the same service.

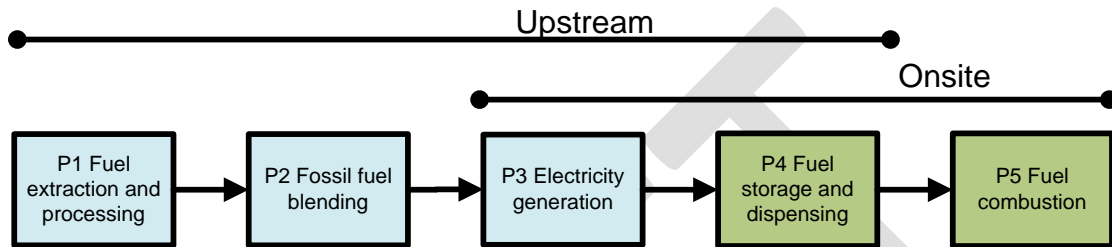


Figure 4: Process Flow Diagram for the Fuel Switching Project Condition

3.1 Identification of Project Sources and Sinks

SS's for the switching of fuels in mobile equipment were identified for the Project Condition by reviewing the Technical Seed Document and the relevant Process Flow Diagram. This process confirmed that sources and sinks identified in **Error! Reference source not found.** address the full scope of eligible project activities under this protocol.

These sources and sinks have been further refined according to the life cycle categories identified in **Error! Reference source not found.** below. These sources and sinks are further classified as controlled, related, or affected as described in **Error! Reference source not found.** below.

This protocol quantifies a direct and indirect reduction in greenhouse gas emissions resulting from a switch to a less GHG-intensive fuel. Thus, sources and sinks are similar to the baseline condition sources and sinks already discussed.

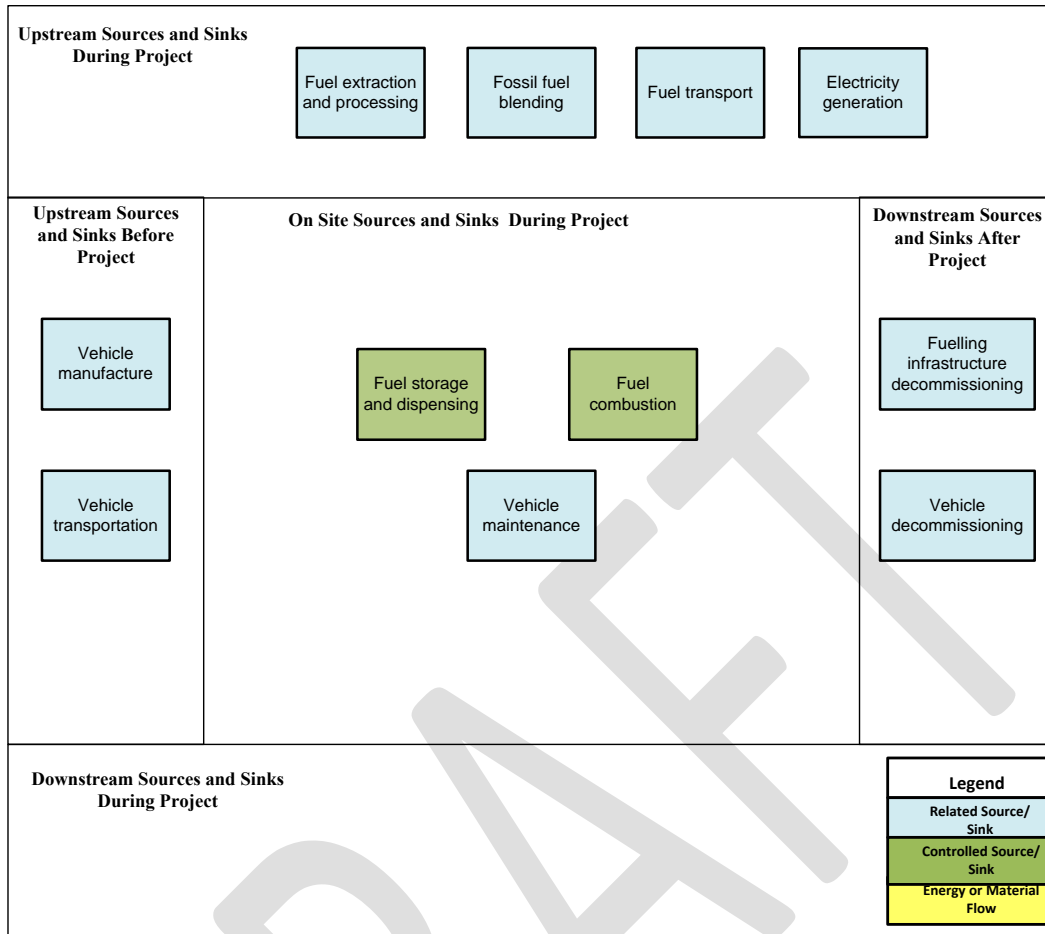


Figure 5: Project Conditions Sources and Sinks for Fuel Switching Protocol.

Table 3: Project Condition Sources and Sinks for the Fuel Switching Protocol

Sources/Sinks	Description	Controlled, Affected, Related
<i>Upstream Sources and Sinks Before Project</i>		
Fuel extraction, and processing	Activities associated with the extraction and production of diesel or gasoline fuel from crude oil or other feedstocks (such as biomass in the case of biodiesel blends).	Related
Fossil fuel blending	Energy associated with production of a blended fuel composed of two or more fossil fuels. Does not include bio fuels.	Related
Vehicle manufacture or modification	Emissions associated with vehicle manufacturing. This includes emissions from assembly plant (electrical power, heating, cooling), materials used in manufacturing, lube oils (production and use) and transport of materials to the assembly facility.	Related
Vehicle transportation	Emissions related to the transportation of the vehicle from the point of manufacture to Alberta. Transportation may include ship, rail and road components	Related
<i>Upstream Sources and Sinks During Project</i>		
Fuel Transport	Transport of alternative fossil fuel from the production facility to the end use location by pipeline, rail, or road. In addition to rail and or truck emissions, emission sources include energy required to pump, compress, or transfer fuel.	Related
Electricity Generation	In the case where electricity is a baseline fuel displaced by a lower-emitting fuel in the project, this electricity would have been generated by a mix of sources on the transmission grid or on-site.	Related
<i>Onsite Sources and Sinks During Project</i>		
Alternative Fuel storage and dispensing	Infrastructure for temporary storage of fuel and dispensing of fuel to vehicles. This includes energy to move (pump), compress, cool, or meter fuel as well as losses due to spills, evaporation, or other fugitive emissions. Emissions for storage and dispensing may be from fuel consumed on site to provide the required energy or from electrical energy use. This includes incremental changes in electrical energy use for different fuel types.	Controlled
Alternative fuel combustion	Combustion of fuel during vehicle operation.	Controlled
Vehicle maintenance	All activities associated with vehicle maintenance. This may include engine oil, lubricants, and replacement tires as well as maintenance facility power, heating and cooling emissions.	Affected
<i>Downstream Sources and Sinks During Project</i>		
<i>Downstream Sources and Sinks After Project</i>		
Alternative fuelling infrastructure decommissioning	Emissions sources for decommissioning of alternative fuelling infrastructure include demolition equipment, transport and recycling of materials, transport and disposal of non recyclable material, and site reclamation.	Related

Vehicle decommissioning	Vehicle decommissioning emission sources include demolition equipment, transport of vehicle to the decommissioning facility, transport and recycling of materials, transport and disposal of non recyclable material.	Related
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4.0 Quantification

Each of the SS's from the Baseline and Project Conditions were compared and evaluated as to their relevancy to determine the scope for reductions quantified under this protocol.

Sources and sinks were either included or excluded depending on how they were impacted by the project condition. Sources not expected to change between baseline and project condition are excluded from quantification.

Where the quantity of emissions generated changes as a result of the project, in comparison to the baseline, the associated emissions are included for quantification. All sources and sinks identified above are listed in **Error! Reference source not found.** Each source and sink is listed as included or excluded. Justification for these choices is provided.

Table 4: Comparison of Sources/Sinks

Identified Sources and Sinks	Baseline (C, R, A)*	Project (C, R, A)*	Include or Exclude from Quantification	Justification for Inclusion/Exclusion
Upstream Sources/Sinks				
Fuel extraction and processing	R	R	Include	This source/sink is project dependent. Additional emissions from project alternative fuel processing and extraction may occur depending on the fuel type. This source/sink may be excluded where emissions occur onsite (see storage and dispensing), where project emissions are within 5% of baseline emissions, or when baseline emissions are greater than project emissions.
Fossil fuel blending	R	R	Include	The energy required for fossil fuel blending of replacement fuel will reduce the potential offset as it is additional to baseline fuel. Fossil fuel blending may also occur in the baseline. Fossil fuel blending would be excluded for projects where it does not occur.
Vehicle manufacture	R	R	Exclude	Little difference is expected between project and baseline vehicle manufacturing emissions, because project and baseline vehicles are required to provide comparable service and will also be comparable in general construction. It is anticipated that both project and baseline vehicles would originate from outside Alberta and the scale of potential projects results in a low expected magnitude of emission.
Vehicle transportation	R	R	Exclude	This source/sink represents an inconsequential fraction of total vehicle lifetime emissions. It is anticipated that both project and baseline vehicles would originate from outside Alberta and additional transportation is likely minimal and prohibitive to quantify accurately. The scale of potential projects results in a low expected magnitude of emission.
Fuel transport	R	R	Exclude	Emissions from fuel transportation within Alberta are expected to remain the same (e.g., fuel blends) or decrease (e.g., CNG, LNG) under the project condition. Thus it is conservative to exclude fuel transportation emissions.
Electricity Generation	R	R	Include	Where electricity is a baseline fuel, the transition to a lower-emitting alternative during the project will result in a reduction of GHG emissions. Alternatively, where a higher-emitting fuel is displaced by electricity during the project, a reduction of emissions, in comparison to the Baseline Condition, is achieved.

Identified Sources and Sinks	Baseline (C, R, A)*	Project (C, R, A)*	Include or Exclude from Quantification	Justification for Inclusion/Exclusion
Onsite Sources/Sinks				
Fuel storage and dispensing	C	C	Include	Emissions for storage and dispensing may be from fuel consumed on site to provide the required energy or from electrical energy use. Depending on the fuel type, the energy to move (pump), compress, cool, or meter fuel as well as losses due to spills, evaporation, or other fugitive emissions may differ considerably between project and baseline conditions. This includes incremental changes in electrical energy use for different fuel types.
Fuel combustion	C	C	Include	CO ₂ , CH ₄ , and N ₂ O emissions will be different between project and baseline fuels.
Vehicle maintenance	A	A	Exclude	Magnitude of change in maintenance is expected to be minimal over vehicle lifetime and prohibitively costly to quantify.
Downstream Sources/Sinks				
Fuelling infrastructure decommissioning	R	R	Exclude	Both baseline and project conditions require similar scale of refuelling infrastructure.
Vehicle decommissioning	R	R	Exclude	Project and baseline condition vehicles are required to provide comparable service and will be comparable in general construction and decommissioning emissions.
Other				
None				

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

4.1 Quantification Methodology

The general quantification approach for greenhouse gas emissions quantification under this protocol is shown below. Each equation is described and broken down in greater detail under individual subheadings, and where required, emissions factors² are provided.

The general equation for calculation of emission reductions is:

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

$$\text{Emissions}_{\text{Baseline}} = \text{Emissions}_{\text{upstream baseline}} + \text{Emissions}_{\text{fuel combustion}}$$

OR

$$\text{Emissions}_{\text{Baseline}} = \text{Emissions}_{\text{fuel extraction and processing}} + \text{Emissions}_{\text{fossil fuel blending}} + \text{Emissions}_{\text{electricity generation}} + \text{Emissions}_{\text{fuel storage and dispensing}} + \text{Emissions}_{\text{fuel combustion}}$$

$$\text{Emissions}_{\text{Project}} = \text{Emissions}_{\text{upstream project}} + \text{Emissions}_{\text{fuel combustion}}$$

OR

$$\text{Emissions}_{\text{Project}} = \text{Emissions}_{\text{fuel extraction and processing}} + \text{Emissions}_{\text{fossil fuel blending}} + \text{Emissions}_{\text{electricity generation}} + \text{Emissions}_{\text{fuel storage and dispensing}} + \text{Emissions}_{\text{fuel combustion}}$$

Note: the methods described as the preferred approach to quantification calculate upstream emissions in a single step that incorporates all the included SS's.

Where:

Emissions_{Baseline} = sum of the emissions included under the Baseline Condition.

Emissions_{Project} = sum of emissions included under the Project Condition.

Discount Factors:

Because the protocol is basing the quantification on project metered fuel consumption, and the emission reduction is an immediate and direct reduction (i.e., no capture or storage), a risk discount factor is not required.

4.2 Baseline Condition Quantification

For the included sources and sinks, the baseline emissions are:

$$\text{Emissions}_{\text{Baseline}} = \text{Emissions}_{\text{upstream}} + \text{Emissions}_{\text{fuel combustion}}$$

Where:

$$\text{Emissions}_{\text{upstream}} = \text{Emissions}_{\text{fuel extraction and processing}} + \text{Emissions}_{\text{fossil fuel blending}} + \text{Emissions}_{\text{electricity generation}} + \text{Emissions}_{\text{fuel storage and dispensing}}$$

² CO₂e emission factors are sum of CO₂, CH₄ and N₂O emissions.

$$\text{Emissions}_{\text{fuel combustion}} = \text{Volume}_{\text{baseline fuel}} \times \text{EF}_{\text{baseline fuel}}$$

And:

$$\text{Emissions}_{\text{fuel extraction and processing}} = \text{Volume}_{\text{baseline fuel}} \times \text{EF}_{\text{extraction and processing}}$$

$$\text{Emissions}_{\text{fossil fuel blending}} = (\sum \text{Volume}_{\text{blended fuel}}) \times \text{Energy}_{\text{per unit volume blended}} \times \text{EF}_{\text{energy}}$$

$$\text{Emissions}_{\text{electricity generation}} = \text{Baseline kWh} \times \text{EF}_{\text{electricity}}$$

$$\text{Emissions}_{\text{fuel storage and dispensing}} = (\text{Energy}_{\text{dispensing}} \times \text{EF}_{\text{energy}}) + (\text{Volume}_{\text{fugitive emissions}} \times \text{EF}_{\text{baseline fuel}})$$

Note: Use of a combined upstream emission factor is the default quantification method. Depending on the fuel type, fuel blending and electricity generation may be excluded.

4.2.1 Emissions upstream

Upstream emissions are all emissions upstream of combustion and include fuel extraction and processing (B1), fossil fuel blending (B2), electricity generation (B3) and fuel storage and dispensing (B4).

4.2.1.1 B1 - Fuel extraction and processing

Emissions for fuel extraction and processing are quantified from an estimated volume of baseline fuel. The volume of baseline fuel is estimated using the Static Historic Benchmark that includes measures of service provided per unit of baseline fuel. Fuel extraction and processing can be quantified separately or combined with the other included upstream sources by use of emission factors from GHGenius or other approved sources as described in **Appendix C**.

For fuel blends, the emissions from fuel extraction and processing for each type of fuel in the blend would be quantified separately and added together.

4.2.1.2 B2 - Fossil fuel blending

Some baseline fuels may be blends of different fossil fuels, though this condition is more likely in the project than in the baseline. The energy used to combine and blend the fuels together is the source that must be quantified if a fossil fuel blend is used, otherwise this source is excluded from the quantification.

The emissions for fossil fuel blending are determined using the same volume of baseline fuel estimated for B1 above multiplied by the energy per unit of fuel blended and the emission factor for the energy source used to do the blending.

4.2.1.3 B3 - Electricity generation

If electricity is a fuel in the baseline then it must be included in the historic benchmark as kWh per unit of service or productivity. Where electricity is not a fuel in the baseline, this source would be excluded from the quantification.

In the case where electricity is a baseline fuel displaced by a lower-emitting fuel in the project, this electricity would have been generated by a mix of sources on the Alberta transmission grid or on-site. The amount (kWh) of electricity would be determined in the

same manner as fossil fuel by using the historic baseline. Emissions would be quantified using the Alberta grid emission factor supplied by Alberta environment or approved project specific emission factor for on-site generation.

4.2.1.4 B4 - Fuel storage and dispensing

Emissions for fuel storage and dispensing are quantified from the same volume of fuel estimated using the same Static Historic Benchmark as described for B1 and B2. The energy required per unit of fuel dispensed may be included in the baseline and used to quantify emissions from fuel dispensing. Fuel storage and dispensing can be quantified separately or combined with the other included upstream sources using GHGenius or other approved sources as described in **Appendix C**.

In addition to the energy used to dispense the fuel, this source includes an estimate of fugitive emissions. Quantification of fugitive emissions is difficult, but they may be measured simply as the difference between the volume deposited into a storage tank and the volume successfully dispensed from the tank. In the case of onsite dispensing it would be the difference between gas dispensed and gas received by the vehicle. GHGenius does incorporate estimates of fugitive emissions and may also be used. Alternatively, the manufacturer of the refuelling technology may supply estimates of fugitive emissions that could be included in the quantification.

Note: For baseline conditions where the refuelling was not controlled by the project developer this source may be difficult to include due to lack of suitable data. It is conservative to exclude this source from the baseline quantification but still include it in the project.

4.2.2 B5 - Fuel combustion

The volume of baseline fuel combusted is estimated using the Static Historic Benchmark that includes measures of service provided per unit of baseline fuel. Emissions are calculated as volume of fuel multiplied by the emission factor (see Appendix C and Appendix E) specific to the type of fuel. For fuel blends, or when multiple fuel types are included in the baseline (e.g., dual fuel or multi fuel engines) the amount of each fuel type would be determined and quantified separately.

4.3 Project Condition Quantification

$$\mathbf{Emissions}_{\text{Project}} = \mathbf{Emissions}_{\text{upstream}} + \mathbf{Emissions}_{\text{fuel combustion}}$$

Where:

$$\mathbf{Emissions}_{\text{upstream}} = \mathbf{Emissions}_{\text{fuel extraction and processing}} + \mathbf{Emissions}_{\text{fossil fuel blending}} +$$

$$\mathbf{Emissions}_{\text{fuel storage and dispensing}}$$

$$\mathbf{Emissions}_{\text{fuel combustion}} = \mathbf{Volume}_{\text{project fuel}} \times \mathbf{EF}_{\text{project fuel}}$$

And:

$$\mathbf{Emissions}_{\text{fuel extraction and processing}} = \mathbf{Volume}_{\text{project fuel}} \times \mathbf{EF}_{\text{extraction and processing}}$$

$$\mathbf{Emissions}_{\text{fossil fuel blending}} = (\sum \mathbf{Volume}_{\text{blended fuel}}) \times \mathbf{Energy}_{\text{per unit volume blended}} \times \mathbf{EF}_{\text{energy}}$$

$$\mathbf{Emissions}_{\text{electricity generation}} = \mathbf{Project kWh} \times \mathbf{EF}_{\text{electricity}}$$

$$\mathbf{Emissions}_{\text{fuel storage and dispensing}} = (\mathbf{Energy}_{\text{dispensing}} \times \mathbf{EF}_{\text{energy}}) + (\mathbf{Volume}_{\text{Fugitive emissions}} \times \mathbf{EF}_{\text{project fuel}})$$

Note: Use of a combined upstream emission factor is the default quantification method. Depending on the fuel type, fuel blending and electricity generation may be excluded.

4.3.1 Emissions upstream

Upstream emissions are all emissions upstream of combustion and include fuel extraction and processing (P1), fossil fuel blending (P2), electricity generation (P3) and fuel storage and dispensing (P4).

4.3.1.1 P1 - Fuel extraction and processing

Emissions for fuel extraction and processing are quantified from the measured volume of project fuel. The volume of project fuel may be established using records of fuel purchase and use or directly through metering. Fuel extraction and processing can be quantified separately or combined with the other included upstream sources by using emission factors from GHGenius or other approved sources as described in Appendix C.

For fuel blends, the emissions from fuel extraction and processing for each type of fuel in the blend would be quantified separately and added together.

4.3.1.2 P2 - Fossil fuel blending

Some project fuels may be blends of different fossil fuels. The energy used to combine and blend the fuels together is the source that must be quantified if a fossil fuel blend is used; otherwise this source is excluded from the quantification.

The emissions for fossil fuel blending are determined using the same measured volume of fuel multiplied by the energy per unit of fuel blended and the emission factor for the energy source used to do the blending.

4.3.1.3 P3 - Electricity generation

Where a higher-emitting fuel is displaced by electricity during the project, a reduction of emissions, in comparison to the Baseline Condition, is achieved. If electricity is a fuel in the project then it must be measured. The amount (kWh) of electricity can be established using power purchase records or directly through metering. Where electricity is not a fuel in the project, this source would be excluded from the quantification.

In the case where electricity is included as a fuel in the project, this electricity would have been generated by a mix of sources on the Alberta transmission grid, or on-site. The amount (kWh) of electricity would be known and emissions would be quantified using the Alberta grid emission factor supplied by Alberta Environment or with approved project specific emission factor for on-site generation.

4.3.1.4 P4 - Fuel storage and dispensing

Fuel storage and dispensing can be quantified separately or combined with the other included upstream sources by use of GHGenius or other approved sources as described in Appendix C.

Emissions for fuel storage and dispensing are quantified from:

- The measured energy used to dispense the measured volume of project fuel, for example (Appendix B), total metered energy required to compress and dispense CNG annually during the project credit period; or,
- The volume of project fuel multiplied by an emission factor per unit of fuel, for example (Appendix B), energy required per kg or m³ of gas compressed and dispensed may be used.

Total metered energy is the preferred method for quantification.

In addition to the energy used to dispense the fuel, this source includes an estimate of fugitive emissions. Project proponents must show that fugitive emissions in the project case are not higher than the baseline case, or must include fugitive emissions in the quantification. Quantification of fugitive emissions is difficult, but they may be measured simply as the difference between the volume deposited into a storage tank and the volume dispensed from the tank. In the case of onsite dispensing it would be the difference between gas dispensed and gas received by the vehicle. Records of fuel supplied to the refuelling station, and of fuel dispensed from the station may be used to substantiate the exclusion of fugitive emissions in the quantification.

The preferred approach when dispensing is not controlled by the project developer is to use GHGenius, which incorporates estimates of Alberta fugitive emissions. Alternatively, the manufacturer of the refuelling technology may supply estimates of fugitive emissions that could be included in the quantification. How fugitive emissions will be handled must be included in the project plan and should be reviewed prior to project start to ensure that the standards for verification can be met.

4.3.2 P5 - Fuel combustion

The volume of project fuel combusted is estimated using the measured volume of fuel and the assumption that all fuel is combusted. Emissions are calculated as volume of fuel multiplied by the appropriate fuel emission factor (see Appendix C). For fuel blends, or when multiple fuel types are included in the project (e.g., dual fuel or multi fuel engines) the amount of each fuel type would be determined and quantified separately.

Table 5: Quantification Methodology

Source/Sink	Parameter / Variable	Unit	Measured/ Estimated	Method	Frequency	Justify measurement or estimation and frequency
Baseline Condition						
$Emissions_{Baseline} = Emissions_{upstream} + Emissions_{fuel\ combustion}$ Where: $Emissions_{upstream} = Emissions_{fuel\ extraction\ and\ processing} + Emissions_{fossil\ fuel\ blending} + Emissions_{electricity\ generation} + Emissions_{fuel\ storage\ and\ dispensing}$ $Emissions_{fuel\ combustion} = Volume_{baseline\ fuel} \times EF_{baseline\ fuel}$						
B1* Fuel extraction and processing	$Emissions_{fuel\ extraction\ and\ processing} = Volume_{baseline\ fuel} \times EF_{extraction\ and\ processing}$					
	$Volume_{baseline\ fuel}$	Litres, m ³ , or kg	Estimated	Static historic benchmark or performance standard baseline	Annually	The amount of baseline fuel is estimated from direct measurements of services provided by the project condition. Services supplied in the project condition are identical to services supplied in the baseline historic benchmark or performance standard.
	$EF_{extraction\ and\ processing}$	gCO ₂ e per unit of fuel	Estimated	From GHGenius model or other approved source for Alberta	Periodic	Emission factors for upstream fuel extraction and processing are periodically updated for Alberta in GHGenius. Due to the many factors that must be considered for this SS, periodic updates are all that is available. Must use most recent version of GHGenius or other approved source.
B2*	$Emissions_{fossil\ fuel\ blending} = (\sum Volume_{blended\ fuel}) \times Energy\ per\ unit\ volume\ blended \times EF_{energy}$					

Source/Sink	Parameter / Variable	Unit	Measured/ Estimated	Method	Frequency	Justify measurement or estimation and frequency
Fossil fuel blending	Volume <i>blended fuel</i>	Litres, m ³ , or kg	Estimated	Volume of each constituent fuel in the blend is calculated proportionally from the total estimated baseline fuel.	Annually	This SS is only included if it occurred in the baseline. The volume would be estimated from the volume of baseline fuel calculated using a historic benchmark or performance standard baseline. Volume must be calculated annually during the project credit period.
	Energy <i>per unit volume blended</i>	kWh per unit of fuel blended	Measured or estimated	Form records of energy required to blend the constituent types together	Periodic	Reviewed periodically when technology or process changes occur.
	EF <i>energy</i>	CO ₂ e per unit of energy	Estimated	From approved Alberta emission factor source.	Periodic	Emission factor for electric power supplied from the Alberta grid is provided by Alberta Environment and is periodically reviewed. Must use most recent Alberta Environment emission factor or an approved project-specific emission factor if energy is supplied for a source other than the Alberta electric grid.
B3 Electricity generation	Emissions <i>electricity generation</i> = Baseline kWh X EF <i>electricity</i>					
	Baseline kWh	kWh	Estimated	Static historic benchmark or performance standard baseline	Annually	Where electricity is a baseline fuel, the use must be included in the baseline as energy per unit of service provided. The kWh are estimated from the measured quantity of service provided in the project multiplied by the baseline kWh per unit of service. This is a static measure and once established will be unchanged throughout the project credit period.

Source/Sink	Parameter / Variable	Unit	Measured/ Estimated	Method	Frequency	Justify measurement or estimation and frequency
	<i>EF</i> <i>electricity</i>	CO ₂ e per unit of energy	Estimated	From approved Alberta Environment or project specific approved source.	Periodic	Emission factor for electric power supplied from the Alberta grid is provided by Alberta Environment and is periodically reviewed. Must use most recent Alberta Environment emission factor or an approved project specific emission factor if energy is supplied from a source other than the Alberta electric grid.
B4* Fuel storage and dispensing	<i>Emissions</i> fuel storage and dispensing = (Energy dispensing X <i>EF</i> energy) + (Volume fugitive emissions X <i>EF</i> baseline fuel)					
	<i>Energy</i> dispensing	kWh	Estimated	Form records of energy required to dispense baseline fuel (historic baseline), from manufacturers reported energy per unit of fuel dispensed or from GHGenius model or other approved source for Alberta.	Periodic	Historic baseline, GHGenius model, or the manufacturer’s specifications may be used. The energy for dispensing may be captured in the historic baseline as energy required per unit of fuel dispensed. Alternatively, the manufacturer’s reported energy per unit of fuel dispensed may be used if the dispensing equipment is known and controlled by the project developer. Energy required for dispensing are periodically updated for Alberta in GHGenius. Must use most recent version of GHGenius or other approved source.
	<i>EF</i> <i>energy</i>	CO ₂ e per unit of energy	Estimated	From approved Alberta emission factor source.	Periodic	Emission factor for electric power supplied from the Alberta grid is provided by Alberta Environment and is periodically reviewed. Must use most recent Alberta Environment emission factor or an approved project specific emission factor if energy is supplied from a source other than the Alberta electric grid.

Source/Sink	Parameter / Variable	Unit	Measured/ Estimated	Method	Frequency	Justify measurement or estimation and frequency
	<i>Volume</i> <i>fugitive emissions</i>	Litres, m ³ , or kg	Estimated	From records of fugitive emissions or from manufacturers reports of fugitive emissions per unit of fuel dispensed. May also be estimated with GHGenius model or other approved source for Alberta.	Periodic	Historic baseline, GHGenius model, or the manufacturer’s specifications may be used. The volume of fugitive emissions may be captured in the historic baseline as fugitive emissions per unit of fuel dispensed. Alternatively, the manufacturer’s reported fugitive emissions per unit of fuel dispensed may be used if the dispensing equipment is known and controlled by the project developer. Energy required for dispensing are periodically updated for Alberta in GHGenius. Must use most recent version of GHGenius or other approved source.
	<i>EF</i> <i>baseline fuel</i>	CO ₂ e per unit of fuel	Estimated	From Environment Canada or other approved Alberta source	Periodic	Must use most current emission factor for the fugitive fuel. Emission factors are periodically updated by Environment Canada and Alberta Environment.
	<i>Emissions</i> <i>fuel combustion</i> = <i>Volume</i> <i>baseline fuel</i> X <i>EF</i> <i>baseline fuel</i>					
B5 Fuel combustion	<i>Volume</i> <i>baseline fuel</i>	Litres, m ³ , or kg	Estimated	Static historic benchmark or performance standard baseline	Annually	The amount of baseline fuel is estimated from direct measurements of services provided by the project condition. Services supplied in the project condition are identical to services supplied in the baseline historic benchmark or performance standard.

Source/Sink	Parameter / Variable	Unit	Measured/ Estimated	Method	Frequency	Justify measurement or estimation and frequency
	<i>EF</i> <i>baseline fuel</i>	CO ₂ e per unit of fuel combusted	Estimated	From Environment Canada reference documents	Annually	Must use most current emission factor for the type of vehicle (e.g., HDDV, off-road Diesel Vehicles) from Environment Canada contained in the National Inventory Report (NIR): Greenhouse Gas Sources and Sinks in Canada.
<p>Project Condition $Emissions_{Project} = Emissions_{upstream} + Emissions_{fuel\ combustion}$ Where: $Emissions_{upstream} = Emissions_{fuel\ extraction\ and\ processing} + Emissions_{fossil\ fuel\ blending} + Emissions_{electricity\ generation} + Emissions_{fuel\ storage\ and\ dispensing}$ $Emissions_{fuel\ combustion} = Volume_{project\ fuel} \times EF_{project\ fuel}$</p>						
P1* Fuel extraction and processing	$Emissions_{fuel\ extraction\ and\ processing} = Volume_{project\ fuel} \times EF_{extraction\ and\ processing}$					
	<i>Volume</i> <i>project fuel</i>	Litres, m ³ , or kg	Measured	Metered volume and or fuel purchase records	Annually	The amount of project fuel is a direct measure of fuel used annually during the project credit period.
	<i>EF</i> <i>extraction and processing</i>	gCO ₂ e per unit of fuel	Estimated	From GHGenius model or other approved source for Alberta	Periodic	Emission factors for upstream fuel extraction and processing are periodically updated for Alberta in GHGenius. Due to the many factors that must be considered for this SS, periodic updates are all that is available. Must use most recent version of GHGenius or other approved source.
P2*	$Emissions_{fossil\ fuel\ blending} = (\sum Volume_{blended\ fuel}) \times Energy_{per\ unit\ volume\ blended} \times EF_{energy}$					

Source/Sink	Parameter / Variable	Unit	Measured/ Estimated	Method	Frequency	Justify measurement or estimation and frequency
Fossil fuel blending	<i>Volume</i> <i>blended fuel</i>	Litres, m ³ , or kg	Measured	Volume of each constituent fuel in the blend is calculated proportionally from the total project fuel volume or from fuel purchase records	Annually	The amount of blended project fuel is calculated as a direct measure of fuel used annually during the project credit period.
	<i>Energy</i> <i>per unit volume blended</i>	kWh per unit of fuel blended	Estimated	Form records of energy required to blend the constituent fuel types together	Periodic	Reviewed periodically when technology or process changes occur.
	<i>EF</i> <i>energy</i>	CO ₂ e per unit of energy	Estimated	From approved Alberta emission factor source.	Periodic	Emission factor for electric power supplied from the Alberta grid is provided by Alberta Environment and is periodically reviewed. Must use most recent Alberta Environment emission factor or an approved project-specific emission factor if energy is supplied from a source other than the Alberta electric grid.
P3 Electricity generation	<i>Emissions</i> <i>electricity generation</i> = <i>Project kWh</i> X <i>EF</i> <i>electricity</i>					
	<i>Project kWh</i>	kWh	Measured	Energy produced or used onsite must be metered.	Annually	Where electricity is a baseline fuel, the transition to a lower-emitting alternative during the project will result in a reduction of GHG emissions. Alternatively, where a higher-emitting fuel is displaced by electricity during the project, a reduction of emissions, in comparison to the Baseline Condition, is achieved.

Source/Sink	Parameter / Variable	Unit	Measured/ Estimated	Method	Frequency	Justify measurement or estimation and frequency
	<i>EF_{electricity}</i>	CO ₂ e per unit of energy	Estimated	From Alberta Environment or approved project specific source.	Periodic	Emission factor for electric power supplied from the Alberta grid is provided by Alberta Environment and is periodically reviewed. Must use most recent Alberta Environment emission factor or an approved project-specific emission factor if energy is supplied from a source other than the Alberta electric grid.
P4* Fuel storage and dispensing	<i>Emissions_{fuel storage and dispensing} = (Energy_{dispensing} X EF_{energy}) + (Volume_{fugitive emissions} X EF_{project fuel})</i>					
	<i>Energy_{dispensing}</i>	kWh	Measured or Estimated	Form records of energy required to dispense project fuel, from manufacturers reported energy per unit of fuel dispensed or from GHGenius model or other approved source for Alberta.	Periodic	Measured energy use, GHGenius model, or the manufacturer's specifications may be used. The energy for dispensing may be measured directly in the project or, alternatively, the manufacturer's reported energy per unit of fuel dispensed may be used if the dispensing equipment is known and controlled by the project developer. If the dispensing equipment is not controlled by the project developer then the most recent version of GHGenius or other approved Alberta source must be used.
	<i>EF_{energy}</i>	CO ₂ e per unit of energy	Estimated	From approved Alberta emission factor source.	Periodic	Emission factor for electric power supplied from the Alberta grid is provided by Alberta Environment and is periodically reviewed. Must use most recent Alberta Environment emission factor or an approved project-specific emission factor if energy is supplied from a source other than the Alberta electric grid.

Source/Sink	Parameter / Variable	Unit	Measured/ Estimated	Method	Frequency	Justify measurement or estimation and frequency
	<i>Volume</i> <i>fugitive emissions</i>	Litres, m ³ , or kg	Measured or Estimated	From records of fugitive emissions or from manufacturers reports of fugitive emissions per unit of fuel dispensed. May also be estimated with GHGenius model or other approved source for Alberta.	Periodic	Measured, GHGenius model, or the manufacturer's specifications may be used. The volume of fugitive emissions may be measured during the project period for onsite equipment under the control of the project developer. Alternatively, the manufacturer's reported fugitive emissions per unit of fuel dispensed may be used if the dispensing equipment is known and controlled by the project developer. If the dispensing equipment is not controlled by the project developer then the most recent version of GHGenius or other approved Alberta source must be used.
	<i>EF</i> <i>project fuel</i>	CO ₂ e per unit of fuel	Estimated	From Environment Canada or other approved Alberta source	Periodic	Must use most current emission factor for the fugitive fuel. Emission factors are periodically updated by Environment Canada and Alberta Environment.
	<i>Emissions</i> <i>fuel combustion</i> = <i>Volume</i> <i>project fuel</i> X <i>EF</i> <i>project fuel</i>					
P5 Fuel combustion	<i>Volume</i> <i>project fuel</i>	Litres, m ³ , or kg	Measured	Metered volume and or fuel purchase records	Annually	The amount of project fuel is measured directly for each year during the project credit period.
	<i>EF</i> <i>project fuel</i>	CO ₂ e per unit of fuel combusted	Estimated	From Environment Canada reference documents	Annually	Must use most current emission factor for the type of vehicle (e.g., HDDV, off-road Diesel Vehicles) from Environment Canada contained in the National Inventory Report (NIR): Greenhouse Gas Sources and Sinks in Canada.

* Note: The preferred method is that upstream emissions be quantified together using GHGenius or other approved Alberta sources. These SS are provided here separately for completeness and to facilitate projects where they are separate (e.g., onsite compression or processing).

5.0 Data Management

Data quality management must be of sufficient quality to fulfill the quantification requirements and be substantiated by actual records for the purpose of verification and for any subsequent government audits.

The project developer shall establish and apply quality management procedures to manage data and information. Written procedures must 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 verification/audit will be conducted for the project.

5.1 Project Documentation

Minimum documentation required for this protocol includes:

5.1.1 Project Eligibility Documentation

- Time and location when project began and activities occurred, including
 - Actions were taken after January 1, 2002 based on fuel procurement and technology procurement records.
 - Have occurred in a period acceptable under Offset System Program Rules
 - In Alberta, including proof of service delivery in Alberta and fuel consumption related to that service.
- The alternative fuel consumed by the Project is not industry standard practice
- The emission reductions claimed are owned by the Project Proponent by proof of fuel and technology purchases.
- Project is not required by law.

5.1.2 Project Quantification Documentation

- Level of service including:
 - Distance travelled by providing vehicle operations/maintenance logs or GPS tracking
 - Equipment capacity including hauling records from weight scales, vehicle capacity in persons carried, etc.
- Amount of energy consumed in fuel storage and dispensing through metered energy consumption and/or proof of purchase of energy.
- Volume of fuel consumed in mobile equipment through metered dispensing and/or proof of purchase of fuel.

5.1.3 Baseline Condition Documentation

Documentation and related proofs are the same between the Project and Baseline Conditions in most cases. Three years of historical data are required or project developers may use the flexibility mechanism. Baseline documentation includes:

- Level of service including:
 - Distance travelled by providing vehicle operations/maintenance logs or GPS tracking
 - Equipment capacity including hauling records from weight scales, vehicle capacity in persons carried, etc.
- Amount of energy consumed in fuel storage and dispensing through metered energy consumption and/or proof of purchase of energy.
- Volume of fuel consumed in mobile equipment through metered dispensing and/or proof of purchase of fuel.

If the flexibility mechanism(s) are used then the following documentation must also be provided:

- Description of sampling design and criteria used in its development
- Results of sampling including summary statistics
- Rational for decision based on results
- Third party validation of methods used and results obtained

5.2 Record Keeping

Alberta Environment requires that project developers maintain appropriate supporting information for the project, including all raw data for the project for a period of 7 years after the end of the project crediting period. Where the project developer is different from the person implementing the activity, as in the case of an aggregated project, the individual projects and the aggregator must both maintain sufficient records to support the offset project. The project developer must keep the information listed below in addition to any other supporting records and disclose all information to the verifier and/or government auditor upon request.

Record-Keeping Requirements:

- Raw baseline data, e.g., transportation fuel use (model output),
- A record of all adjustments made to raw baseline data with justifications,
- Metering equipment specifications (model number, serial number, manufacturer's calibration procedures),
- A record of changes in static factors along with all calculations for non-routine adjustments,
- All calculations of greenhouse gas emissions/reductions and emission factors,
- Measurement equipment maintenance activity logs,
- Measurement equipment calibration records,
- Initial and annual verification records and audit results.

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

- All records must be kept in areas that are easily located,
- All records must be legible, dated and revised as needed,
- All records must be maintained in an orderly manner,
- All documents must be retained for 7 years after the project crediting period,
- Electronic and paper documentation are both satisfactory,
- Copies of records should be stored in two locations to prevent loss of data.

Note: Attestations are not considered sufficient evidence that an activity has occurred and will not be accepted by Alberta Environment as proof that the activity took place.

5.3 Quality Assurance/Quality Control Considerations

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

- Ensuring that the changes of fuel type continue to function as planned and achieve greenhouse gas reductions,
- Ensuring that the measurement and calculation system and greenhouse gas reduction reporting remains in place and accurate,
- Checking the validity of all data before it is processed, including emission factors, static factors, and acquired data,
- Performing recalculations of quantification procedures to reduce the possibility of mathematical errors,
- Storing the data in its raw form so it can be retrieved for verification,
- Protecting records of data and documentation by keeping both a hard and soft copy of all documents,
- Recording and explaining any adjustment made to raw data in the associated report and files,
- A contingency plan for potential data loss.

5.4 Liability

Offset projects must be implemented according to the approved protocol and in accordance with government regulations. Alberta Environment reserves the right to audit Offset credits and associated projects submitted to Alberta Environment for compliance under the *Specified Gas Emitters Regulation* and may request corrections based on audit findings.

6.0 References

National Inventory Report 1990–2008: Greenhouse Gas Sources and Sinks in Canada. Available from

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Appendix A Example of Baseline and Project Condition
Calculation and Guidance on Applying Flexibility Mechanisms I
& II

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The general equation for calculation of emission reductions is:

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

Where:

Emissions_{Baseline} = sum of the emissions included under the Baseline Condition.

Emissions_{Project} = sum of emissions included under the Project Condition.

For the included sources and sinks, the baseline emissions are:

$$\text{Emissions}_{\text{Baseline}} = \text{Emissions}_{\text{upstream}} + \text{Emissions}_{\text{fuel combustion}}$$

Where:

$$\text{Emissions}_{\text{upstream}} = \text{Emissions}_{\text{fuel extraction and processing}} + \text{Emissions}_{\text{fossil fuel blending}} +$$

$$\text{Emissions}_{\text{electricity generation}} + \text{Emissions}_{\text{fuel storage and dispensing}}$$

$$\text{Emissions}_{\text{fuel combustion}} = \text{Volume}_{\text{baseline fuel}} \times \text{EF}_{\text{baseline fuel}}$$

And:

$$\text{Emissions}_{\text{fuel extraction and processing}} = \text{Volume}_{\text{baseline fuel}} \times \text{EF}_{\text{extraction and processing}}$$

$$\text{Emissions}_{\text{fossil fuel blending}} = (\sum \text{Volume}_{\text{blended fuel}}) \times \text{Energy}_{\text{per unit volume blended}} \times \text{EF}_{\text{energy}}$$

$$\text{Emissions}_{\text{electricity generation}} = \text{Baseline kWh} \times \text{EF}_{\text{electricity}}$$

$$\text{Emissions}_{\text{fuel storage and dispensing}} = (\text{Energy}_{\text{dispensing}} \times \text{EF}_{\text{energy}}) + (\text{Volume}_{\text{fugitive emissions}} \times \text{EF}_{\text{baseline fuel}})$$

For the included sources and sinks, the project emissions are:

$$\text{Emissions}_{\text{Project}} = \text{Emissions}_{\text{upstream}} + \text{Emissions}_{\text{fuel combustion}}$$

Where:

$$\text{Emissions}_{\text{upstream}} = \text{Emissions}_{\text{fuel extraction and processing}} + \text{Emissions}_{\text{fossil fuel blending}} +$$

$$\text{Emissions}_{\text{fuel storage and dispensing}}$$

$$\text{Emissions}_{\text{fuel combustion}} = \text{Volume}_{\text{project fuel}} \times \text{EF}_{\text{project fuel}}$$

And:

$$\text{Emissions}_{\text{fuel extraction and processing}} = \text{Volume}_{\text{project fuel}} \times \text{EF}_{\text{extraction and processing}}$$

$$\text{Emissions}_{\text{fossil fuel blending}} = (\sum \text{Volume}_{\text{blended fuel}}) \times \text{Energy}_{\text{per unit volume blended}} \times \text{EF}_{\text{energy}}$$

$$\text{Emissions}_{\text{electricity generation}} = \text{Project kWh} \times \text{EF}_{\text{electricity}}$$

$$\text{Emissions}_{\text{fuel storage and dispensing}} = (\text{Energy}_{\text{dispensing}} \times \text{EF}_{\text{energy}}) + (\text{Volume}_{\text{Fugitive emissions}} \times \text{EF}_{\text{project fuel}})$$

Note: Use of a combined upstream emission factor is the default quantification method. Depending on the fuel type, fuel blending and electricity generation may be excluded.

Example 1. Mobile source simple case with combined emission factors

Project scenario: Ten new CNG public transportation busses instead of 10 diesel busses in large urban system. In this example CNG is not produced on site.

Baseline scenario (BAU case): continued use of 10 diesel busses.

Project plan: CNG is a lower greenhouse gas emission fuel than diesel fuel. The project condition quantification of emissions will include measures of service provided (passenger capacity and distance traveled) as well as fuel combusted, energy to dispense and store fuel, fugitive emissions, and upstream fuel extraction and processing. The measures of service provided during the project (i.e., passenger capacity km) will be used to estimate baseline fuel volume using a static historic benchmark. Once calculated, baseline fuel volume will be used to estimate emissions from baseline fuel combustion,

energy to dispense and store baseline fuel, baseline fuel fugitive emissions, and upstream baseline fuel extraction and processing.

Calculations: The example calculations are broken down into steps, explained in Parts A through F.

A) During the project planning phase the proponent identified the need for establishing the required historic benchmark baseline. This should be the first step in all projects as failure to establish the baseline will halt the project.

The current (baseline) bus fleet contains 100 busses each with a 50 passenger capacity (number of seats). Three years of baseline information for the entire 100 bus fleet were available as follows:

year	litres	passenger cap	km
1	3400000	5000	8500000
2	3500000	5000	8750000
3	3300000	5000	8250000

The passenger capacity km per litre (Pcap km per L) was calculated for each year as:

$$\text{Pcapkm/L}_{\text{year}} = (\text{passenger capacity} \times \text{km}) / \text{litres}$$

$$\text{Pcapkm/L}_{\text{Year 1}} = (5000 \times 8500000) / 3400000 = 0.00008$$

$$\text{Pcapkm/L}_{\text{Year 2}} = (5000 \times 8750000) / 3500000 = 0.00008$$

$$\text{Pcapkm/L}_{\text{Year 3}} = (5000 \times 8250000) / 3300000 = 0.00008$$

The average for the three years is used as the historic benchmark baseline and is calculated as:

$$\text{Pcapkm/L}_{\text{baseline}} = (\text{Pcapkm/L}_{\text{Year 1}} + \text{Pcapkm/L}_{\text{Year 2}} + \text{Pcapkm/L}_{\text{Year 3}}) / 3 = 0.00008$$

Later calculations will also require baseline passenger capacity. This is calculated as the average passenger capacity used to establish the baseline:

$$\text{Pcap}_{\text{baseline}} = (\text{Passenger capacity}_{\text{year 1}} + \text{Passenger capacity}_{\text{year 2}} + \text{Passenger capacity}_{\text{year 3}}) / 3 \text{ years} = 5000$$

Note: because three complete years were available there was no need to establish a monitoring program to collect the required data. The baseline is created from a census of the entire bus fleet, and not a representative sample, therefore there is no need to calculate confidence intervals for the data.

Table A1. Flexibility mechanism for calculating historic benchmark using a subsample.

Alternate method for calculating historic benchmark using subsample
Issue: no data is currently available for fuel use and distance traveled.
Plan: monitor one years worth of fuel consumption and distance traveled for a sample of busses.
Considerations: need a statistically representative sample of bus fuel use and distance traveled. Must select appropriate sample size and operating conditions (e.g., differences between winter and summer fuel use).
Step 1: select a number of busses at random from the current fleet that are comparable to the replacement busses. The larger the sample size the greater the confidence in the estimation. It is recommended that the sample size be selected to meet the desired confidence level.
Step 2: for each of the selected busses monitor total fuel used and total km traveled over one full year.
Step 3: calculate the passenger capacity km per litre (Pcap km per L) for each bus as in the example above.
Step 4: calculate summary statistics including the mean, standard deviation from the mean, and 95% confidence interval for the busses. Include summary statistics in the project supporting documentation.
Step 5: use the summary statistics to decide what the historic baseline (Pcap km per L) value should be. In general terms if the standard deviation is small then the mean should be used as the baseline, if the standard deviation is high (e.g., 25% or more of the mean) then the <u>upper</u> bound of the 95th percentile confidence interval should be used. This will ensure that the quantification meets the requirements to be conservative and not overestimate.

B) Initiate and monitor the project. After one full year of monitoring the 10 CNG busses resulted in the following data.

Bus #	Litres		
	CNG	passenger cap	km
1	34,560	50	80,000
2	33,696	50	78,000
3	36,720	50	85,000
4	34,992	50	81,000
5	35,424	50	82,000
6	35,856	50	83,000
7	38,016	50	88,000
8	36,288	50	84,000
9	31,104	50	72,000
10	34,128	50	79,000
Project Total	350,784	500	812,000

C) Calculate the baseline emissions for combustion. Baseline emissions are calculated as follows:

$$\mathbf{Emissions}_{Baseline} = \mathbf{Emissions}_{upstream} + \mathbf{Emissions}_{fuel\ combustion}$$

Because there is no fuel blending and electricity is not a baseline or project fuel, we can exclude emissions from these sources. Thus baseline upstream emissions are:

$$\mathbf{Emissions}_{upstream} = \mathbf{Emissions}_{fuel\ extraction\ and\ processing} + \mathbf{Emissions}_{fuel\ storage\ and\ dispensing}$$

In order to perform the calculations we first need to determine the volume of baseline fuel combusted. This volume is estimated from the total passenger capacity and km traveled using the historic benchmark from Part A above and the following formula:

$$\text{Volume}_{\text{baseline fuel}} = (\text{total project passenger cap} \times \text{total project km}) \times \text{Pcapkm} / \text{L}_{\text{baseline}} \times (\text{Pcap} / \text{total project passenger cap})$$

Where:

$$\text{total project passenger cap} = 500$$

$$\text{total project km} = 812,000$$

$$\text{Pcapkm/L}_{\text{baseline}} = 0.00008$$

$$\text{Pcap}_{\text{baseline}} = 5000$$

Thus:

$$\text{Volume}_{\text{baseline fuel}} = (500 \times 812,000) \times 0.00008 \times (5000 / 500) = 324,800 \text{ L}$$

This volume is the litres of baseline fuel (diesel) that would have been combusted in the absence of the project (i.e., by diesel busses instead of CNG project busses).

Using an emission factor from the most recent NIR or other approved source we can determine the greenhouse gas emissions from baseline fuel combustion. Each greenhouse gas (CO₂, CH₄, N₂O) should be calculated separately in CO₂ equivalent units and converted to tonnes.

$$\text{Emissions}_{\text{fuel combustion}} = \text{Volume}_{\text{baseline fuel}} \times \text{EF}_{\text{baseline fuel}}$$

Where:

$$\text{Volume}_{\text{baseline fuel}} = 324,800 \text{ L}$$

$$\text{EF}_{\text{baseline fuel}} (\text{CO}_2) = 2663 \text{ g/L}$$

$$\text{EF}_{\text{baseline fuel}} (\text{CH}_4) = 0.12 \text{ g/L CO}_2\text{e using a GWP of 21}$$

$$\text{EF}_{\text{baseline fuel}} (\text{N}_2\text{O}) = 0.082 \text{ g/L CO}_2\text{e using a GWP of 310}$$

$$\text{Emissions}_{\text{fuel combustion}} = (324,800 \text{ L} \times 2663) + (324,800 \text{ L} \times 0.12) + (324,800 \text{ L} \times 0.082)$$

$$\text{Emissions}_{\text{fuel combustion}} = 865,008,010 \text{ g CO}_2\text{e} = 865 \text{ tonnes CO}_2\text{e}$$

D) Use the estimated baseline fuel volume to calculate the baseline emissions from fuel extraction and processing, and from fuel storage and dispensing.

$$\text{Emissions}_{\text{fuel extraction and processing}} = \text{Volume}_{\text{baseline fuel}} \times \text{EF}_{\text{extraction and processing}}$$

$$\text{Emissions}_{\text{fuel storage and dispensing}} = (\text{Energy}_{\text{dispensing}} \times \text{EF}_{\text{energy}}) + (\text{Volume}_{\text{fugitive emissions}} \times \text{EF}_{\text{baseline fuel}})$$

Upstream emissions are calculated with the use of the GHGenius model that contains Alberta specific factors (see Section 9.1.1). For this example the Transport Canada UTEC model that provides emission factors in an easy-to-use g/L CO₂e format will be used (Note: the UTEC model is based on an earlier version of the GHGenius model and is used here for demonstration). Using a combined emission factor, we can rewrite the equation for emissions from fuel extraction and processing and from fuel storage and dispensing into a single combined upstream equation.

$$\text{Emissions}_{\text{upstream}} = \text{Volume}_{\text{baseline fuel}} \times \text{EF}_{\text{upstream}}$$

Where:

$$\text{Emissions}_{\text{upstream}} = \text{greenhouse gas emissions upstream of combustion}$$

$$\text{Volume}_{\text{baseline fuel}} = \text{estimated baseline fuel volume}$$

$$\text{EF}_{\text{upstream}} = \text{combined emission factor for upstream greenhouse gas emissions}$$

Using an upstream diesel fuel emission factor from the UTEC model of 724 g/L CO_{2e} we can calculate baseline emissions as follows:

$$\begin{aligned} \mathbf{Emissions}_{upstream} &= \mathbf{Volume}_{baseline\ fuel} \times \mathbf{EF}_{upstream} \\ \mathbf{Emissions}_{upstream} &= 324,800\ \text{L} \times 724\ \text{g/L} = 235,155,200\ \text{g} = 235\ \text{tonnes CO}_2\text{e} \end{aligned}$$

E) Calculate the project condition emissions. Project condition emissions are obtained primarily from direct measurement of fuel and energy use combined with estimates of upstream emissions.

$$\mathbf{Emissions}_{Project} = \mathbf{Emissions}_{fuel\ extraction\ and\ processing} + \mathbf{Emissions}_{fossil\ fuel\ blending} + \mathbf{Emissions}_{fuel\ storage\ and\ dispensing} + \mathbf{Emissions}_{fuel\ combustion}$$

As with the baseline there is no fuel blending so it can be excluded:

$$\mathbf{Emissions}_{Project} = \mathbf{Emissions}_{upstream} + \mathbf{Emissions}_{fuel\ combustion\ project}$$

Using the measured volume of CNG combusted and the emission factor provided by the UTEC model we can calculate emissions from fuel combustion as:

$$\mathbf{Emissions}_{fuel\ combustion\ project} = \mathbf{Volume}_{project\ fuel} \times \mathbf{EF}_{project\ fuel}$$

In this example we will use combined CO_{2e} emission factors rather than repeating the calculations for CH₄ and N₂O (i.e., CO₂ + CH_{4e} + N₂Oe = 1690 g/L of CNG).

$$\begin{aligned} \mathbf{Emissions}_{fuel\ combustion\ project} &= 350,784\ \text{L} \times 1690\ \text{g/L CO}_2\text{e} \\ \mathbf{Emissions}_{fuel\ combustion\ project} &= 592,824,000\ \text{g CO}_2\text{e} = 592\ \text{tonnes CO}_2\text{e} \end{aligned}$$

As we did with the baseline we can use a single upstream emission factor for the project condition. Using an upstream CNG fuel emission factor from the UTEC model of 381.3 g/L CO_{2e} we can calculate baseline emissions as follows:

$$\begin{aligned} \mathbf{Emissions}_{upstream\ project} &= \mathbf{Volume}_{project\ fuel} \times \mathbf{EF}_{upstream} \\ \mathbf{Emissions}_{upstream\ project} &= 350,784\ \text{L} \times 381.3\ \text{g/L} = 133,753,000\ \text{g CO}_2\text{e} = 133\ \text{tonnes CO}_2\text{e} \end{aligned}$$

F) The final step is to calculate the emission reduction. Emission reductions are:

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

For this example we can summarize as:

$$\mathbf{Emission\ Reduction} = (\mathbf{Emissions}_{upstream} + \mathbf{Emissions}_{fuel\ combustion}) - (\mathbf{Emissions}_{upstream\ project} + \mathbf{Emissions}_{fuel\ combustion\ project})$$

$$\mathbf{Emission\ Reduction} = (235\ \text{tonnes} + 865\ \text{tonnes}) - (133\ \text{tonnes} + 592\ \text{tonnes}) = \mathbf{375\ \text{tonnes CO}_2\text{e}}$$

For projects where the service has not been supported in the past (e.g., a town is establishing bus service or curb side garbage pickup for the first time), the historic benchmark baseline is not applicable. In this case a **Static, Performance Standard** approach can be used and is included as a flexibility mechanism described in table A2 below.

Table A2. Flexibility mechanism for calculating a baseline using a Performance Standard.

Guidance for development of a Static Performance Standard Baseline
Issue: There is no history of the activity upon which to develop a Historic Benchmark Baseline. For example; a growing rural community introducing bus service or curb side garbage pickup for the first time.
Plan: Option 1: Identify a suitable analogous community and initiate monitoring as described for establishing the baseline using a subsample. Option 2: acquire a number of baseline vehicles and operate them under normal conditions in the project area and employ the subsample flexibility mechanism. Option 3: obtain 3 years of data from a suitable analog community for the baseline activity.
Considerations: As with the sub sampling flexibility mechanism a statistically representative sample of fuel use and service provided must be collected. Additional considerations include: terrain is similar to the proposed project area, level of service and distances traveled must be comparable to the proposed project, and services provided must be representative of the business as usual scenario (e.g., cannot select an old inefficient fleet of vehicles to use for establishing the performance baseline). Because this protocol relies on measure of service provision, the manufacturers supplied estimates of fuel consumption cannot be used. The performance baseline must be established using data collected in Alberta under normal operating conditions.
Step 1: select an option (1, 2, or 3) as described above and justify selection.
Step 2: for options 1 and 2, determine the appropriate sampling frequency and sample size.
Step 3: for options 1 and 2 follow the steps described for establishing a baseline using a subsample.
Step 4: calculate summary statistics including the mean, standard deviation from the mean, and 95% confidence interval for the data collected. Include summary statistics in the project supporting documentation.
Step 5: use the summary statistics to decide if additional monitoring is required. If the standard deviation is high (> 50% of the mean) additional monitoring is likely required. Repeat steps 2-4 as needed.
Step 6: use the summary statistics to decide what the Performance Standard Baseline should be. Normally when the standard deviation is small the mean should be used as the baseline, and if the standard deviation is high (e.g., 25% or more of the mean) then the upper bound of the 95th percentile confidence interval should be used. Because the time for data collection is compressed (i.e., 3 years were not used) the upper bound of the 95th percentile should be used for the baseline, not the mean. Note: additional sampling can be used to reduce the size of the confidence interval.

Appendix B Guidance on Applying Flexibility Mechanism III

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Example 2. Mobile source with on-site fuel compression

This example will use the same scenario as Example 1 above except that onsite compression of natural gas will be included.

Project scenario: Ten new CNG public transportation busses instead of 10 diesel busses in large urban system. The busses are fueled from a dedicated CNG station located at the maintenance yard.

Baseline scenario (BAU case): continued use of 10 diesel busses.

Project plan: CNG is a lower greenhouse gas emission fuel than diesel fuel. The project condition quantification of emissions will include measures of service provided (passenger capacity and distance traveled) as well as fuel combusted, energy to dispense and store fuel, fugitive emissions, and upstream fuel extraction and processing. The measures of service provided during the project (i.e., passenger capacity km) will be used to estimate baseline fuel volume using a historic benchmark. Once calculated baseline fuel volume will be used to estimate emissions from baseline fuel combustion, energy to dispense and store baseline fuel, baseline fuel fugitive emissions, and upstream baseline fuel extraction and processing.

Calculations: The example calculations are broken down into steps, explained in Parts A through F.

A) During the project planning phase the proponent identified the need for establishing the required historic benchmark baseline. This should be the first step in all projects as failure to establish the baseline will halt the project.

The current (baseline) bus fleet contains 100 busses each with a 50 passenger capacity (number of seats). Three years of baseline information for the entire 100 bus fleet were available as follows:

year	litres	passenger cap	km
1	3400000	5000	8500000
2	3500000	5000	8750000
3	3300000	5000	8250000

The average passenger capacity km per litre (Pcap km per L) and passenger capacity are unchanged from Example 1:

$$Pcap_{km/L \text{ baseline}} = 0.00008$$

$$Pcap_{\text{baseline}} = 5000$$

B) Initiate and monitor the project. After one full year of monitoring the 10 CNG busses resulted in the following data.

Bus #	kg CNG	Litres CNG	passenger	
			cap	km
1	6393.6	34,560	50	80,000
2	6233.8	33,696	50	78,000
3	6793.2	36,720	50	85,000
4	6473.5	34,992	50	81,000
5	6553.4	35,424	50	82,000
6	6633.4	35,856	50	83,000
7	6393.6	38,016	50	88,000
8	6713.3	36,288	50	84,000
9	5754.2	31,104	50	72,000
10	6313.7	34,128	50	79,000
Project Total	64255.7	350,784	500	812,000

Unlike the previous example, natural gas compression was done onsite so the energy required to operate the compression and refueling station was also monitored. Total energy for the project year was 128511.4 kWh. This was metered energy use and includes energy required for gas compression.

C) Calculate the baseline emissions for combustion. Baseline Combustion emissions are unchanged from Example 1.

$$\mathbf{Emissions}_{Baseline} = \mathbf{Emissions}_{upstream} + \mathbf{Emissions}_{fuel\ combustion}$$

$$\mathbf{Volume}_{baseline\ fuel} = (\text{total project passenger cap} \times \text{total project km}) \times P_{capkm} / L_{baseline} \times (P_{cap} / \text{total project passenger cap})$$

$$\mathbf{Volume}_{baseline\ fuel} = 324,800 \text{ L (calculation shown in Example 1)}$$

This volume is the litres of baseline fuel (diesel) that would have been combusted in the absence of the project (i.e., by diesel busses instead of CNG project busses).

Using an emission factor from the most recent NIR or other approved source we can determine the greenhouse gas emissions from baseline fuel combustion (calculations shown in Example 1).

$$\mathbf{Emissions}_{fuel\ combustion} = \mathbf{Volume}_{baseline\ fuel} \times \mathbf{EF}_{baseline\ fuel}$$

$$\mathbf{Emissions}_{fuel\ combustion} = 865 \text{ tonnes CO}_2\text{e}$$

D) Use the estimated baseline fuel volume to calculate the baseline emissions upstream of combustion. This is also unchanged from Example 1.

$$\mathbf{Emissions}_{upstream} = \mathbf{Volume}_{baseline\ fuel} \times \mathbf{EF}_{upstream} = 235 \text{ tonnes CO}_2\text{e}$$

Where:

$\mathbf{Emissions}_{upstream}$ = greenhouse gas emissions upstream of combustion

$\mathbf{Volume}_{baseline\ fuel}$ = estimated baseline fuel volume

$\mathbf{EF}_{upstream}$ = combined emission factor for upstream greenhouse gas emissions

E) Calculate the project condition emissions. Project condition emissions are obtained primarily from direct measurement of fuel and energy use combined with estimates of upstream emissions.

$$\mathbf{Emissions}_{Project} = \mathbf{Emissions}_{upstream} \mathbf{Emissions}_{fuel\ extraction\ and\ processing} + \mathbf{Emissions}_{fossil\ fuel\ blending} + \mathbf{Emissions}_{fuel\ storage\ and\ dispensing} + \mathbf{Emissions}_{fuel\ combustion\ project}$$

Where:

$$\mathbf{Emissions}_{fuel\ combustion\ project} = \mathbf{Volume}_{project\ fuel} \mathbf{X} \mathbf{EF}_{project\ fuel}$$

$$\mathbf{Emissions}_{upstream} = \mathbf{Emissions}_{fuel\ extraction\ and\ processing} + \mathbf{Emissions}_{fossil\ fuel\ blending} + \mathbf{Emissions}_{fuel\ storage\ and\ dispensing}$$

As with the baseline there is no fuel blending so it can be excluded, thus:

$$\mathbf{Emissions}_{upstream} = \mathbf{Emissions}_{fuel\ extraction\ and\ processing} + \mathbf{Emissions}_{fuel\ storage\ and\ dispensing}$$

Calculation of emissions from fuel combustion remains the same as shown in Example 1.

$$\mathbf{Emissions}_{fuel\ combustion\ project} = \mathbf{Volume}_{project\ fuel} \mathbf{X} \mathbf{EF}_{project\ fuel} = 592 \text{ tonnes CO}_2\text{e}$$

Unlike Example 1, natural gas is compressed onsite and the energy required must be included as a source in the project condition. In this example a single combined emission factor for upstream emissions cannot be used and each source must be examined separately.

$$\mathbf{Emissions}_{upstream} = \mathbf{Emissions}_{fuel\ extraction\ and\ processing} + \mathbf{Emissions}_{fuel\ storage\ and\ dispensing}$$

Where:

$$\mathbf{Emissions}_{fuel\ extraction\ and\ processing} = \mathbf{natural\ gas\ extraction\ and\ processing}$$

$$\mathbf{Emissions}_{fuel\ storage\ and\ dispensing} = \mathbf{onsite\ natural\ gas\ compression\ and\ dispensing} \\ = (\mathbf{Energy}_{dispensing} \mathbf{X} \mathbf{EF}_{energy}) + (\mathbf{Volume}_{fugitive\ emissions} \mathbf{X} \mathbf{EF}_{baseline\ fuel})$$

Fuel extraction and processing for the natural gas feedstock is calculated as described in section 9.1.1 with the help of the GHGenius model.

Fuel storage and dispensing is calculated from metered energy required to compress and dispense the compressed natural gas, or is calculated based on energy required per kg or m³ of gas compressed and dispensed. Total metered energy is the preferred method for quantification.

Project proponents must show that fugitive emissions in the project case are not higher than the baseline case, or must include fugitive emissions in the quantification.

Quantification of fugitive emissions are difficult but may be measured simply as the difference between the volume deposited into a storage tank and the volume dispensed from the tank. In the case of onsite dispensing it would be the difference between gas dispensed and gas received by the vehicle. GHGenius does incorporate estimates of fugitive emissions and may also be used. Alternatively, the manufacturer of the refuelling technology may supply estimates of fugitive emissions that could be included in the quantification. In this example the refuelling technology used results in negligible fugitive emissions as natural gas is compressed on demand the uses the latest plug in

technology. Records of gas supplied to the refuelling station, and of gas dispensed from the station, may be used to substantiate the exclusion of fugitive emissions in the quantification. How fugitive emissions will be handled must be included in the project plan and should be reviewed prior to project start to ensure that the standards for verification can be met.

$$\mathbf{Emissions}_{fuel\ storage\ and\ dispensing} = (\mathbf{Energy}_{dispensing} \times \mathbf{EF}_{energy}) + (\mathbf{Volume}_{fugitive\ emissions} \times \mathbf{EF}_{baseline\ fuel})$$

Where:

$\mathbf{Energy}_{dispensing}$ = kWh for refuelling facility during the project crediting period = 128511.4 kWh

\mathbf{EF}_{energy} = Emission factor for energy used = 0.882 tCO₂e/MWh for Alberta (from Alberta Environment)

$\mathbf{Volume}_{fugitive\ emissions}$ = Excluded. Justification must be provided for exclusion.

$\mathbf{EF}_{baseline\ fuel}$ = Emission factor for fugitive emissions.

$$\mathbf{Emissions}_{fuel\ storage\ and\ dispensing} = (\mathbf{Energy}_{dispensing} \times \mathbf{EF}_{energy}) = 128.5 \times 0.882 = 113\ \text{tCO}_2\text{e}$$

Upstream natural gas fuel extraction and processing is determined with the help of GHGenius. From version 4.0 of the GHGenius model we get an estimate of 330g CO₂e/kg CNG.

$\mathbf{Emissions}_{fuel\ extraction\ and\ processing} = \mathbf{natural\ gas\ extraction\ and\ processing}$

$$\mathbf{Emissions}_{fuel\ extraction\ and\ processing} = 330\text{g CO}_2\text{e/kg CNG} \times 64255.7\ \text{kg CNG} = 21\ \text{tonnes CO}_2\text{e}$$

F) The final step is to calculate the emission reduction. Emission reductions are:

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

For this example we can summarize as:

$$\mathbf{Emission\ Reduction} = (\mathbf{Emissions}_{upstream} + \mathbf{Emissions}_{fuel\ combustion}) - (\mathbf{Emissions}_{upstream} + \mathbf{Emissions}_{fuel\ combustion\ project})$$

$$\mathbf{Emission\ Reduction} = (235\ \text{tonnes} + 865\ \text{tonnes}) - ((113\ \text{tonnes} + 21\ \text{tonnes}) + 592\ \text{tonnes}) = \mathbf{374\ \text{tonnes CO}_2\text{e}}$$

Table B1. Flexibility mechanisms for calculating energy use for onsite natural gas compression.

Alternate method for calculating energy per unit of fuel dispensed for onsite natural gas compression
Issue: Onsite natural gas compression is in use and no facility energy metering is in place
Plan: monitor a sample of months or of individual fills for the project buses using temporary metering to derive a energy per unit volume of natural gas dispensed (e.g., kWh/kg, kWh/m ³)
Considerations: need a statistically representative sample of fills or months. Must select appropriate sample size and operating conditions (e.g., differences between winter and summer energy use).
Step 1: perform an initial exploratory sampling of energy use under typical operating conditions ensuring that factors likely to impact energy consumption are included. For example sequential fills may consume more energy in a multistage CNG compression facility than a single fill. This initial sample must be sufficiently large enough to allow for a reasonable representation of energy use per unit of natural gas dispensed (sample size of 30 or more is recommended). The larger the sample size the greater the confidence in the estimation.
Step 2: calculate summary statistics for the initial sample including mean, standard deviation from the mean, and 95% confidence interval for each fill sampled.
Step 3: based on the distribution of the initial sampling determine the method of sampling and the required sample size. If energy use per unit of natural gas dispensed varies little between individual fills then a single continuous sampling period may be used (e.g., monitor total energy use and amount of fuel dispensed for a 3 month period). If the amount of energy use per unit of natural gas dispensed varies between fills then use the initial sample data to determine a sample size that will produce the desired confidence level (accuracy). Use of initial sampling to determine sample size based on desired level of confidence is a highly recommended and common statistical approach.
Step 4a: if a single continuous sample design has been selected monitor total energy use and total fuel dispensed for the selected time period to determine a energy per unit of natural gas dispensed (e.g., kWh/kg, kWh/m ³). Report the results from the initial sampling in the project documentation to support the decision to use a single continuous sample period.
Step 4b: where a single continuous monitoring design was not selected, monitor the energy used and amount of gas dispensed for each of the number of fills determined in step 3 above.
Step 5: calculate summary statistics including the mean, standard deviation from the mean, and 95% confidence interval for the sample. Include summary statistics in the project supporting documentation.
Step 6: use the summary statistics to decide what the energy use per unit of fuel dispensed value should be. In general terms if the standard deviation is small then the mean should be used as the baseline, if the standard deviation is high (e.g., 25% or more of the mean) then the lower bound of the 95th percentile confidence interval should be used. This will ensure that the quantification meets the requirements to be conservative and not overestimate. Note: if step 3 was performed properly then the sample size used should yield a mean estimate with the desired level of confidence.

Appendix C Default Emission Factors & Guidance on Justifying Alternative Emission Factors

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A number of emission factors (EFs) are required for use of this protocol. These will include emission factors for baseline and project fuel combustion, fossil fuel blends or blending, and emissions upstream of combustion including fuel extraction, processing, and storage and dispensing.

The primary source for most emission factors is the National Inventory Report³ (NIR). The NIR is the Canadian government's submission to the UN framework convention on climate change, and Part Two of the Report contains both stationary and mobile emission factors for most of the fuels anticipated under the proposed protocol. The other acceptable source recommended for use is the GHGenius model⁴. The GHGenius model includes upstream emissions and can be used to derive Alberta-specific upstream emissions for a variety of fuels and fuel feedstocks.

To facilitate use of the proposed protocol, a combined upstream emission quantification including fuel extraction and processing as well as fuel storage and dispensing is recommended. When additional fuel processing occurs within a project (e.g., onsite natural gas compression for CNG or LNG vehicles) then the additional energy required would be quantified separately, and the appropriate emission factor from the NIR would be applied.

For electricity supplied from a dedicated project source, the fuel used to generate the power would be included as a source (e.g., onsite combustion of natural gas to power CNG compression and refuelling). For projects that require quantification of electrical power that is not derived from a dedicated source or solely from the Alberta power grid, alternative electricity emission factors may also be used. However, in cases where the alternative electrical source is also connected to the Alberta power grid, issues of leakage and additionality must be clearly defined in the project plan and Alberta Environment must be consulted. For example; a large forest company may locate a CNG or LNG compression and refuelling station adjacent to its operations facility to service its truck fleet and to use electrical power from its cogeneration plant consuming biomass. However, if that same cogeneration plant supplies power to the Alberta power grid then leakage and additionality must be addressed in the project plan, and Alberta Environment must be consulted.

Upstream emission quantification

Work in progress. Don O'Connor has agreed to contribute this section.

- Where to find the latest version of the GHGenius model
- Source of data used for upstream sources or reference to supporting docs
- How to use the model to determine upstream emissions

Upstream sources contained in GHGenius include (grams CO₂e/GJ):

- Fuel dispensing
- Fuel distribution and storage

³ Most recent NIR available from <http://www.ec.gc.ca/ges-ghg/>

⁴ Available from <http://www.ghgenius.ca>

- Fuel production
- Feedstock transmission
- Feedstock recovery
- Feedstock Upgrading
- Land-use changes, cultivation
- Fertilizer manufacture
- Gas leaks and flares
- CO₂, H₂S removed from NG
- Emissions displaced

Calculating a single combustion emission factor for blended fuel

In addition to a complete switch of fuel type, this protocol is intended for use with switching to a lower greenhouse gas emission intensity fossil fuel blend. Depending on the quantification method selected, a single (combined) fuel emission factor may be used that incorporates all of the constituent fuels into a single unit of fuel (e.g., g/L), or separate emission factors for each constituent of the blended fuel may be used. For stationary facilities, calculating greenhouse gas emissions using separate emission factors for each fuel constituent is recommended. This will simplify the calculations, reduce the chance of error, and reduce the number of required calculations. For mobile sources, a single (combined) emission factor may be used. A single emission factor for mobile sources will reduce the number of calculations required and the chance of error. This would apply to dual fuel engines that consume small quantities of diesel in combination with natural gas to overcome issues with compression or for engines that consume a fuel mixture that is blended prior to combustion. A single emission factor is not recommended for multi fuel engines that are capable of using different fuels types but only one at a time. For multi fuel engines each fuel would be tracked and quantified separately. The emission factors required for use of this protocol must be from accepted sources (e.g., National Inventory Reports, Environment Canada, Transport Canada) or be approved by Alberta Environment. Guidance on selection and use of emission factors for the Alberta Offset System is provided in the *Technical Guidance for Offset Protocol Developers (Version 1.0. January 2011)*. The recommended method for calculating a single emission factor for fossil fuel blends is provided below. This method may also be used to adjust baseline fuel emission factors to accommodate changes to fuel composition following implementation of renewable fuel standards. The following assumptions must be true to use the approach described here:

1. Each constituent of the blended fuel must have an emission factor from an acceptable source.
2. The combustion efficiency of the blended fuel must be similar (within 5%) or better than each fuel combusted individually.

Volume-based emission factor calculation:

$$EF = \sum_{i,j} VF_{i,j} \times EF_j$$

Where:

EF is the combined emission factor for one unit of fuel composed of i volume of j constituent fuel

$VF_{i,j}$ is the volume (ratio) i of constituent fuel j in one unit of fuel

EF_j is the emission factor for one unit of fuel j

Note: due to the Alberta requirement to separately report CO₂, CH₄ and N₂O emissions the calculation would be repeated for each greenhouse gas.

Example

A hypothetical project fuel contains a blend of 80% standard diesel and 20% natural gas. The accepted emission factors (Transport Canada UTEC calculator) for one unit (g/L) of diesel are 2663 CO₂, 0.12 CH₄, and 0.082 for N₂O. For natural gas the accepted emission factors (g/L) are 1212 CO₂, 0.5950 CH₄, and 0.1170 for N₂O. Note that the units for each fuel are the same (i.e., g/L) – when the units for each constituent are different they must be converted to a common unit before calculating the combined emission factor.

$$EF = \sum_{i,j} Vol_{i,j} \times EF_j$$

Substituting the appropriate values for CO₂ into the equation for both fuel constituents we get the following:

$$EF_{CO_2} = (0.8 \times 2663) + (0.2 \times 1212)$$

$$EF_{CO_2} = 2372.8 \text{ g/L}$$

For emissions of CH₄ and N₂O, do the same as for CO₂:

$$EF_{CH_4} = (0.8 \times 0.12) + (0.2 \times 0.5950) = 0.215 \text{ g/L}$$

$$EF_{N_2O} = (0.8 \times 0.082) + (0.2 \times 0.1170) = 0.08902 \text{ g/L}$$

As a final step the global warming potential (GWP) of 21 for CH₄ and 310 for N₂O can be used to convert to the required CO₂ equivalent units.

$$EF_{CH_4} = 4.515 \text{ g/L CO}_2\text{e}$$

$$EF_{N_2O} = 27.599 \text{ g/L CO}_2\text{e}$$