QUANTIFICATION PROTOCOL FOR FUEL SWITCHING IN MOBILE EQUIPMENT

Version: 1.0

February 2013

Specified Gas Emitters Regulation

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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1.0 Offset Project Description

This quantification protocol describes the process for quantifying greenhouse gas emission reductions resulting from converting mobile fleets to lower-greenhouse gas intensity fuels while maintaining an equal or greater level of service.

Greenhouse gas reductions are achieved by replacing conventional fuels (diesel and gasoline) with lower greenhouse gas fuels using lifecycle emissions for the fuels. This includes direct emissions from combustion and indirect emissions related to fuel extraction, processing, and blending.

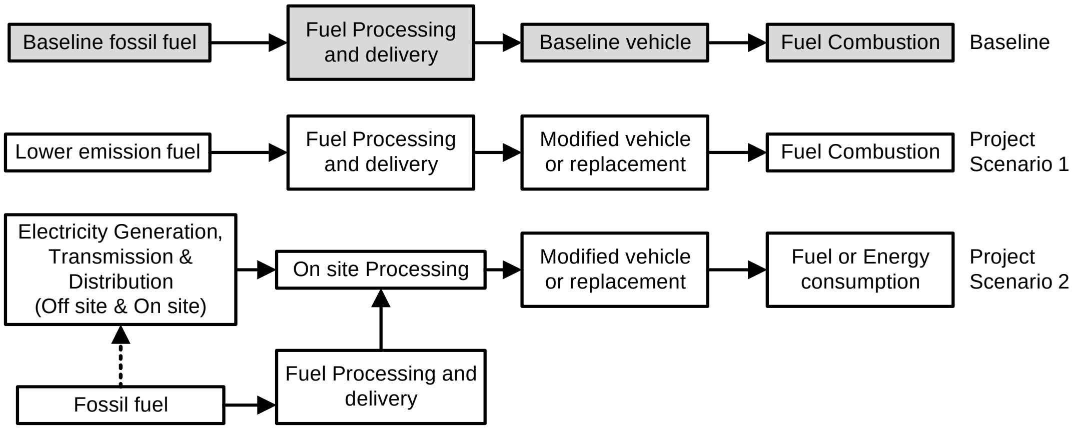
Eligible replacement fuels include lower greenhouse gas fossil fuels, fossil fuel blends, and electricity. Greenhouse gas emissions associated with biofuels and biomass materials are quantified under other protocols[1] and are excluded from this protocol.

Reductions are measured on a service provision basis to ensure actual reductions in greenhouse gas emissions relative to the baseline condition. 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, agriculture).

Figure 1 below shows a process flow diagram for the baseline and three potential project conditions for mobile sources.

[1] A complete listing of approved quantification protocols is available at: http://environment.alberta.ca/02275.html

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



1.1 Protocol Scope

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

The protocol includes flexibility to allow existing fossil fuel technologies or systems with new technologies or systems to utilize lower emitting fuels or electricity. Flexibility is also provided to accommodate new build projects that are designed to use lower emitting fuels. Flexibility options are discussed in Section 1.3 below.

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

- Diesel
- Gasoline
- 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
- Propane

Biogas, biomass, biofuels, and renewable fuels are **excluded** from the scope of this protocol. Projects may include a combination of biofuels and lower greenhouse gas fossil fuels. Reductions from these types of projects must be correctly attributed to, and quantified under the appropriate protocol(s), and may be included in one larger project for the purposes of serializing emissions reductions. More information on stacking protocols is available in the Technical Guidance for Offset Project Developers.

This protocol uses a **static historic** baseline. Baseline fuel is calculated using a historic intensity measure of energy per unit of service (e.g., Litres of diesel per tonne·km of freight transported) multiplied by the units of service measured during the project. This ensures emission reductions account for an equal level of service between the baseline and project condition. This methodology also accounts for emission reductions associated with annual variation and/or growth in service.

Functional equivalence (consistency between baseline and project) is achieved by using a common intensity metric – units of carbon dioxide equivalent (CO_2e) or unit of fuel consumed per unit of service defined in the project. The units used in the baseline must be the same as the units measured during the project monitoring phase (e.g., passenger capacity·km, tonnes·km).

The baseline emission factors provided in Appendix E for mobile sources incorporates applicable renewable fuel standards to ensure the intensity of the baseline fuel accurately reflects current regulatory requirements. These numbers are subject to periodic review. Updated emission factors must be used when approved.

Relevant greenhouse gas emissions for this protocol are shown in Table 1 below, and CO_2e emission factors are described in Appendix E.

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_2O	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 other related guidance documents. In particular, the project developer must provide sufficient evidence to demonstrate:

- Verifiable records on fuel use for each year of the baseline period and project condition (years in which offset credits are being claimed); and
- Verifiable records for the service provided for each year of the baseline period and project condition. Acceptable service measures are;
  - passenger capacity·km (transit projects),
  - tonnes·km (freight transportation),
  - harvest m^3 (forest harvesting),
  - area harvested or worked (agriculture).

Project initiated under this protocol must also meet the following criteria:

- The fuel must be consumed in Alberta. Where mobile emissions also occur outside Alberta, only the portion of fuel consumed in Alberta is eligible to generate offset credits or be used to establish the baseline;
- The alternative fuel must have a lower greenhouse gas emission intensity compared to the baseline fuel. Fuel comparison is based on service delivery and/or productivity (e.g., emissions per passenger capacity·km, emissions per tonnes·km) equivalent;
- When the project requires that existing vehicles be replaced, the new vehicles must provide the same services as the original vehicles. Note, the quantity of service may change with the implementation of a project;
- Must demonstrate that the most likely baseline scenario is the continuation of use of the higher carbon intensive fuel; and
- There is no regulation requiring a change in baseline fuel use.

1.3 Protocol Flexibility

Three flexibility mechanisms are provided. They are described below:

1. **Projects with less than three years of census data:** In situations where projects have less than three years of census information available to support a static historic baseline, the baseline can be quantified using the statistical sampling methodology described in Appendix A**.** This appendix provides example calculations including clarification on how to use statistical sampling.

   New projects must use a performance standard baseline described in Appendix B. The project developer must have sufficient data to support the quantification of the performance standard baseline in conformance with the requirements provided in this protocol.

   Note: These two flexibility mechanisms <u>cannot be applied</u> if suitable census information exists, or where sufficient historical data can be collected prior to project initiation (e.g., baseline data can be collected after the project plan has been developed and before project initiation).

2. Site specific emission factors may be substituted for the generic emission factors indicated in this protocol document. The methodology for generating these emission factors must meet program requirements for accuracy and requirements stated in Appendix E. The methodology must be fully documented in the offset project plan.

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

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

1.4 Glossary of New Terms

Term	Description
Alberta Renewable Fuels Standard (RFS)	A renewable fuels standard is a government requirement to blend renewable products into commercial fuels. Alberta's Renewable Fuels Standard (RFS) requires an average of two per cent renewable diesel in diesel fuel and five per cent renewable alcohol in gasoline sold in Alberta. Renewable fuels used to meet the RFS must demonstrate at least 25 per cent fewer greenhouse gas emissions than the equivalent petroleum fuel.
Biofuel	A type of fuel derived from biological carbon fixation and includes solid biomass, liquid fuels and various biogases.
Biogas	See Biofuel.
Biomass	Non-fossilized and biodegradable organic material originating from plants, animals and micro-organisms.
Census data	Collection of data from every member of a statistical population. Descriptive measures (e.g., average) calculated from census data are assumed to be true, while measures calculated from samples are estimates of the true values. The Alberta Offset System considers three years of data collection to be a true census. See also Statistically Representative Sample.
Compressed Natural Gas - CNG	CNG is made by compressing natural gas to 2900–3600 psi. CNG may be used as a lower greenhouse gas emission substitute for fossil fuels including gasoline, diesel, and propane/LPG.
Dual Fuel Engine	Typically diesel and natural gas, a Dual Fuel diesel engine is an engine that has been fitted with additional devices allowing it to utilize natural gas as a supplemental fuel.
Fossil Fuel	Fossil fuels are fuels containing high carbon content formed by natural processes millions of years ago. Fossil fuels include coal, crude oil, and natural gas.
Fossil Fuel Blend	A mixture of fossil fuels with a different greenhouse gas emission profile than the unblended fuel.
Fugitive Emission	Fugitive emissions are unintentional emissions of gases or vapours.
Liquid Natural Gas Products - LNG	Liquefied natural gas or LNG is natural gas that has been converted to liquid form by cooling it to approximately −162 °C. Liquefied natural gas takes up about 1/600th the volume of natural gas in the gaseous state. LNG achieves a higher reduction in volume than compressed natural gas (CNG) so that the energy density of LNG is 2.4 times that of CNG.
Sample	See Statistically Representative Sample.

Replacement fuel	The type of fuel that will be used in the project (project fuel) to replace the fuel type that otherwise would be used (baseline fuel).
Statistically representative sample	Collection of data from a number of units picked at random from a statistical population. To ensure sample units are representative of the population of interest, the population can be stratified or filtered before unit selection. The number of units selected for data collection can vary but in general should be greater than thirty to ensure confidence in population estimates.

2.0 Baseline Condition

This protocol requires that project developers establish a **static historic** baseline for the project activity. This baseline must be established using a minimum of three years of complete census information including the amount of fuel combusted and the service provided (e.g., transportation of people or freight, agriculture or forest harvesting). Section 1.3 and relevant appendices provide information for quantifying baselines where three years of census data is not available, and for new projects.

The baseline condition is defined as the fuel or mix of fuels that were consumed prior to implementing a project to displace these fuels with lower greenhouse gas emitting alternative fuels. Fossil fuels must be consumed to provide services including hauling of freight or passengers, or operating heavy equipment. The project developers must be able to demonstrate the types and amounts of fuels consumed in the baseline and the level of service or productivity that was provided

The baseline is established using a measure of productivity per unit of fuel consumed. This productivity measure is then used to calculate baseline emissions based on the estimated quantity of fuel required to provide the same level of service as the known (measured) project condition. This ensures emission reductions account for an equal level of service between the baseline and the project condition (i.e., maintain functional equivalence). It also accommodates emission reductions associated with a growth in service provided where lower greenhouse gas intensive fuel(s) is/are utilized in place of the higher intensive baseline fuel(s).

Note: both the baseline and project condition must use a common metric of units of carbon dioxide equivalent (CO_2e) and measures of service (e.g., passenger·km, tonnes·km, units harvested, area worked). Hours of operation or distance traveled cannot be used alone to establish baseline fuel use. They must be used in conjunction with a measure of performance or productivity

Further, technological and/or regulatory changes in fuel and efficiency requirements must be applied to the baseline, including:

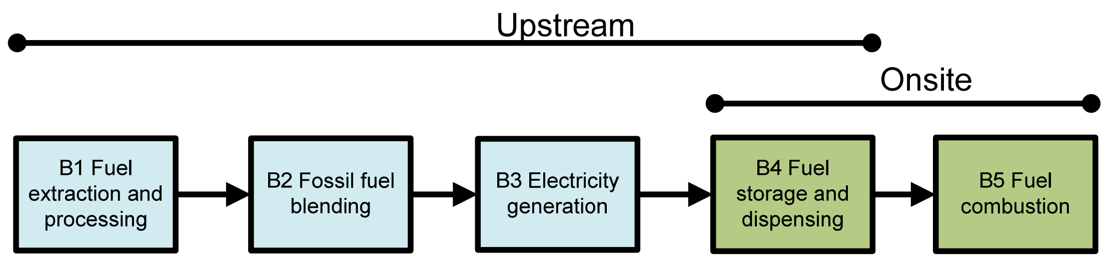
- Use of current emission factors and methodologies as described in Appendix E;
- Adjustments are made for government mandates that lower the greenhouse gas intensity of the baseline fuel(s), (i.e. Renewable Fuel Standards, Low-Carbon Fuel Standards, or similar regulatory program); and
- Adjustments are made to emission factors for mandatory sector level technology changes that affect engine efficiency that occur during the 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** baseline approach must be used (See Section 1.3 and Appendix B).

This protocol is applicable to a large variety of fuel switching projects. Some baselines may have additional processing or handling of the fuel feedstock and this may occur onsite or upstream. These additional processes must be documented in the offset project plan and included in the baseline and project quantification.

Figure 2 below shows the process flow for the baseline condition.

Figure 2: Process Flow Diagram for the Baseline Condition.



2.1 Sources and Sinks

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.

Figure 3 classifies baseline emissions according to this classification.

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

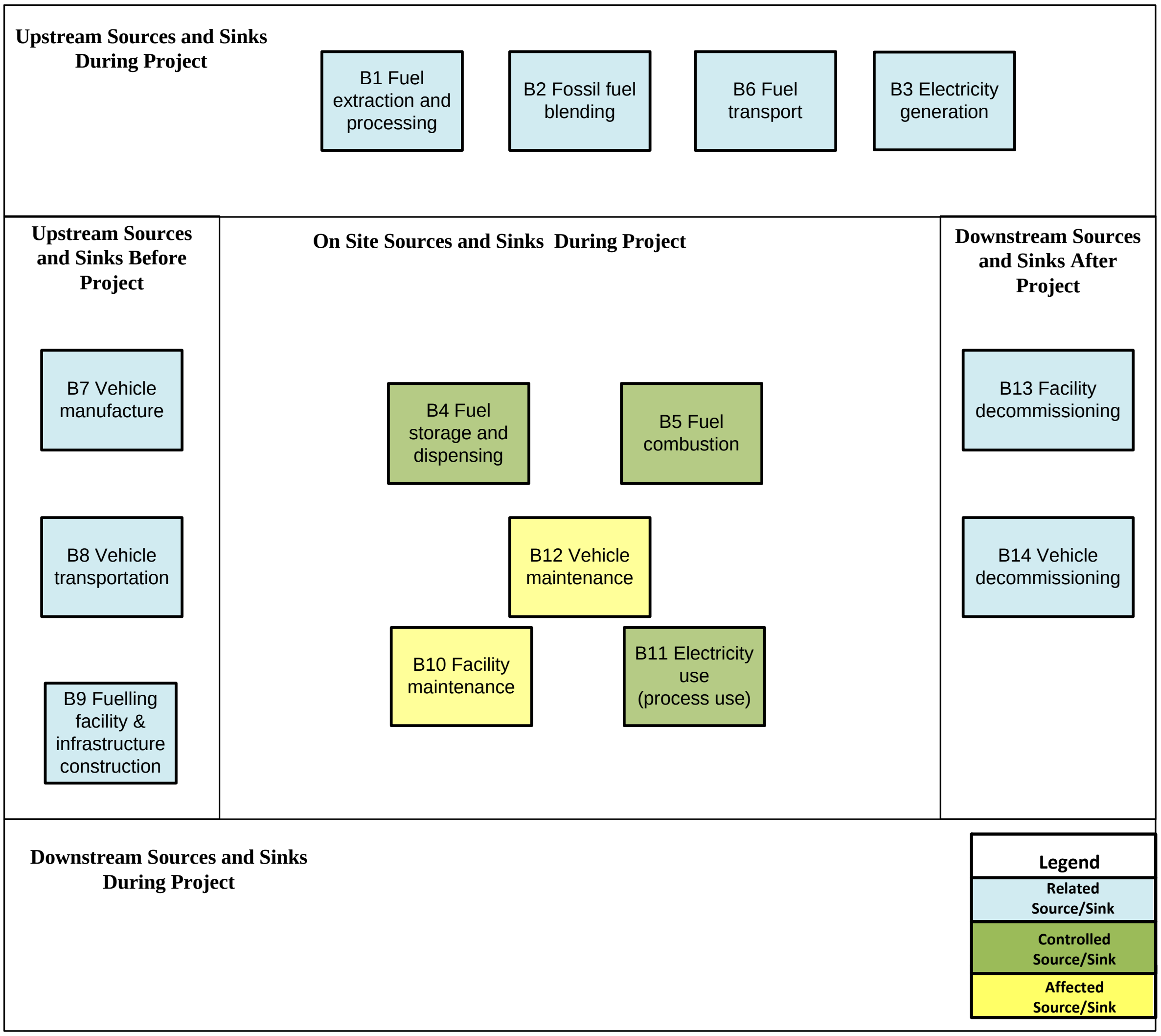


Table 2: Baseline Sources and Sinks

Sources/Sinks	Description	Controlled, Affected, Related
Upstream Sources and Sinks Before Project		
B7 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
B8Vehicle 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
B 9 Fuelling facility and infrastructure construction	Emissions sources for construction of alternative fuelling facility and associated infrastructure. This includes material and material transportation, assembly, heating and lighting used during construction, as well as facility testing and start-up.	Related
Upstream Sources and Sinks During Project		
B1 Fuel extraction and processing.	Activities associated with the extraction and production of diesel or gasoline fuel from crude oil or other feedstocks.	Related
B2 Fossil fuel blending	Energy associated with production of a blended fuel composed of two or more fossil fuels. Does not include bio fuels.	Related
B3 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
B6 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
Onsite Sources and Sinks During Project		
B4 Fuel storage and dispensing*	Infrastructure for 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.	Controlled
B5 Fuel combustion	Combustion of fuel during vehicle operation.	Controlled
B10 Facility Maintenance	Activities associated with facility maintenance. This may include energy to operate, clean and or repair maintenance facility.	Affected

B11 Electricity use. (Process use)	Electricity used to power facility processes..	Controlled
B12 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
Downstream Sources and Sinks During Project		
	Not applicable	
Downstream Sources and Sinks After Project		
B13 Facility decommissioning	Decommissioning of infrastructure for temporary storage of fuel and dispensing of fuel to vehicles. Emissions sources include demolition equipment, transport and recycling of materials, transport and disposal of non recyclable material, and site reclamation.	Related
B14 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

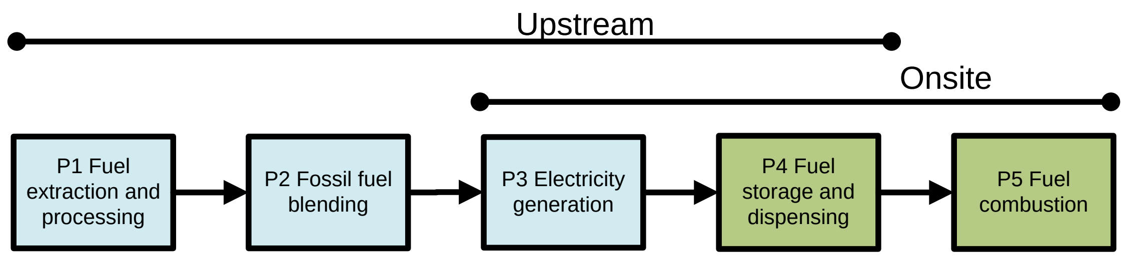
3.0 Project Condition

The project condition is defined as the emissions associated with the use of fuel(s) with lower life-cycle greenhouse gas emissions intensities compared to the fuel or fuel mixes consumed during the baseline condition. Fuel use and levels of service during the project condition are measured directly and then compared to an amount of fuel that would have been consumed under baseline conditions to provide the same level of service.

This protocol is applicable to a large variety of fuel switching projects. Some projects may have additional processing or handling of the fuel feedstock (e.g., compression of natural gas to CNG or LNG) or generation of power, and this may occur onsite or upstream. These additional processes must be documented in the offset project plan and included in the baseline and project quantification.

Figure 4 below shows a simplified process flow for the project condition.

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



3.1 Identification of Project Sources and Sinks

The sources and sinks for fuel switching projects in mobile equipment been further classified as controlled, related, or affected as shown in Figure 5 and described in Table 5 below.

Both direct and indirect reduction in greenhouse gas emissions resulting from a switch to a lower greenhouse gas intensive fuels must be quantified. Thus, sources and sinks in the project condition are similar to the baseline condition sources and sinks already discussed.

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

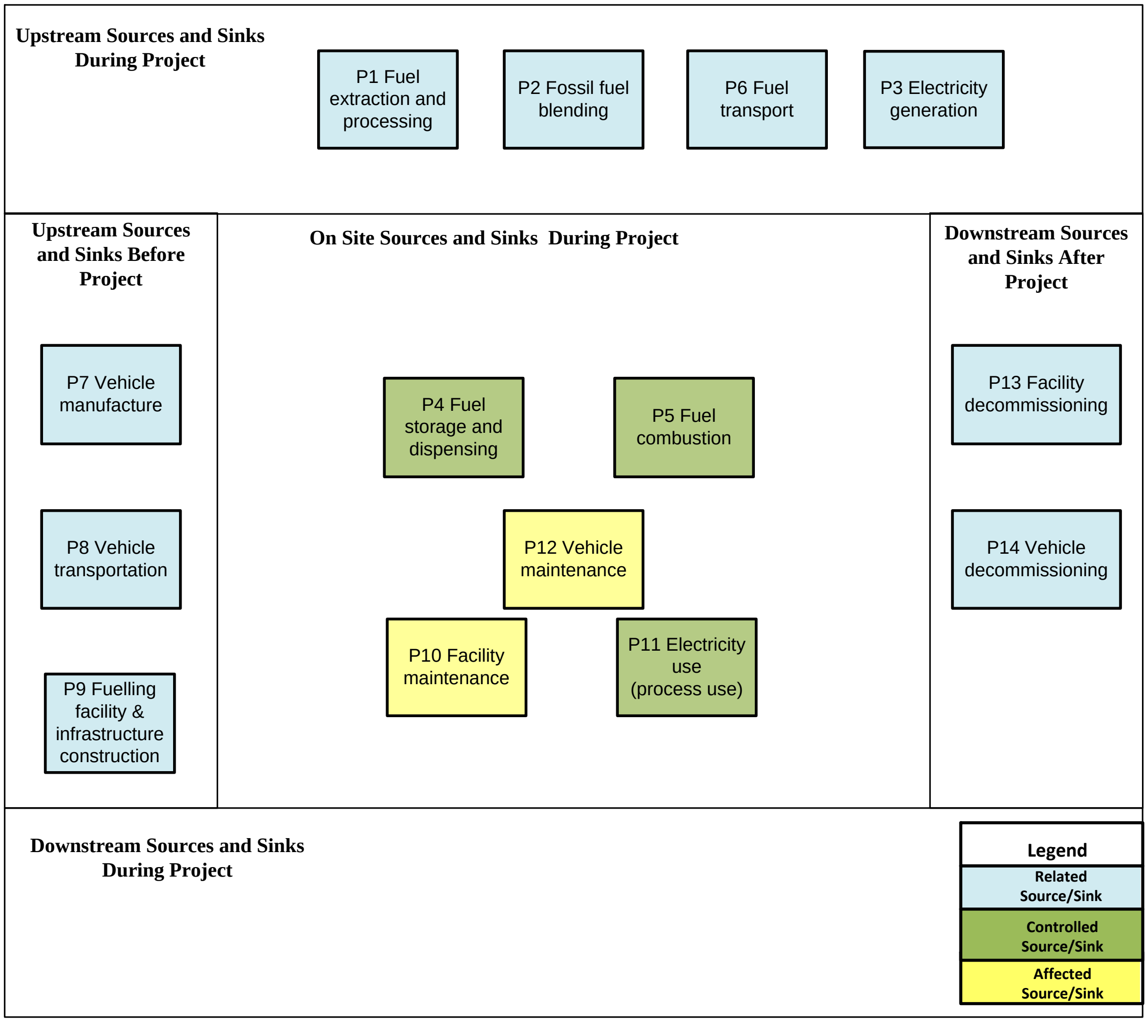


Table 3: Project Condition Sources and Sinks for the Fuel Switching Protocol.

Sources/Sinks	Description	Controlled, Affected, Related
Upstream Sources and Sinks Before Project		
P7 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
P8Vehicle 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
P9 Fuelling facility infrastructure and construction	Emissions sources for construction of alternative fuelling facility and associated infrastructure. This includes material and material transportation, assembly, heating and lighting used during construction, as well as facility testing and start-up.	Related
Upstream Sources and Sinks During Project		
P1 Fuel extraction and processing	Energy is consumed during the extraction and production of fuels from crude oil or other feedstocks.	Related
P2 Fossil fuel blending	Energy is consumed during the production of a blended fuel composed of two or more fossil fuels. This source applies to additional blending that may occur after initial fuel extraction and processing. Blending may occur on site prior to fueling of mobile equipment or integrated within mobile equipment and occur just prior to combustion..	Related
P3 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
P6 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
Onsite Sources and Sinks During Project		
P4 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 of electrical energy use for different fuel types.	Controlled

P5 Fuel combustion	Combustion of fuel during vehicle operation will result in a direct emission from the vehicle tailpipe.	Controlled
P10 Facility Maintenance	Activities associated with facility maintenance. This may include energy to operate, clean and or repair maintenance facility.	Affected
B11 Electricity use. (Process use)	Electricity used to power facility processes.	Controlled
P12 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
Downstream Sources and Sinks DuringProject		
Not applicable		
Downstream Sources and Sinks After Project		
P13 Facility 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
P14 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

* may occur onsite and or upstream.

3.2 Validation

Validation is optional in the Alberta Offset System, but is encouraged for complex projects. Validation is highly recommended for fuel switching projects to ensure all requirements of the Alberta Offset System are met before starting the project.

4.0 Quantification

Each of the sources and sinks from the baseline and project conditions were compared and evaluated to assess their relevancy for the purposes of quantifying greenhouse gas emissions reductions from fuel switching projects. 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. Emissions reductions that are expected to change as a result of project implementation are included in the quantification.

All sources and sinks identified above are listed in Table 4 and are listed as included or excluded. Justification for the inclusion/exclusion 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				
B1/P1 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 when baseline emissions are greater than project emissions. Use of comprehensive fuel emission factors will include this source.
B2/P2 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. Additional fossil fuel blending may also occur in the baseline. This source applies to additional blending that may occur after initial fuel extraction and processing. Blending may occur on site prior to fueling of mobile equipment or integrated within mobile equipment and occur just prior to combustion. Additional fossil fuel blending is excluded for projects where it does not occur or where it occurs with initial fuel extraction and processing and is already captured in the fuel emission factor.
B3/P3 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 greenhouse gas emissions. Alternatively, where a higher-emitting fuel is displaced by electricity during the project result in a reduction in greenhouse gas emissions.
B6/P6 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.
B7/P7 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 therefore, will also be comparable in general construction. It is anticipated that both project and baseline vehicles would originate from outside Alberta and emissions

				associated with vehicle manufacture will be low.
B8/P8 Vehicle transportation	R	R	Exclude	This source/sink represents the 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.
B9/P9 Fuelling facility and infrastructure construction	R	R	Exclude	Differences in facility construction between project and baseline are expected to be minimal. Given the small scale and wide variety of potential project types it would be prohibitively costly to collect the required baseline and project construction emission information.
Onsite Sources/Sinks				
B4/P4 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 of electrical energy use for different fuel types.
B5/P5 Fuel combustion	C	C	**Include**	CO_2, CH_4, and N_2O emissions will be different between project and baseline fuels.
B10/P10	A	A	Exclude	Magnitude of change in maintenance is expected to be minimal over project lifetime and prohibitively costly to quantify.
B11/P11 Electricity use	C	C	Exclude	Electricity use for facility processes are not expected to change or are likely to increase due to the project. Electricity use related to fuel switching activities is captured in P4.
B12/P12 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				
B13/P13 Facility decommissioning	R	R	Exclude	Both baseline and project conditions require similar scale of refuelling infrastructure.
B14/P14 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 quantifying greenhouse gas emissions under this protocol is shown below. Emission factors are provided where required.

The general equation for calculating emission reductions is:

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

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

or

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

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

or

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

Note:

Where:

$\text{Emissions}_{\text{Baseline}}$ = sum of the emissions included under the Baseline Condition.

$\text{Emissions}_{\text{Project}}$ = sum of emissions included under the Project Condition.

Note: greenhouse gas emissions reductions quantified under this protocol a must use metered fuel consumption. Further, it is recommended that project developers calculate all upstream emissions in a single step that includes all relevant sources and sinks.

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:

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

$$\text{Emissions}_{\text{fuel combustion}} = \text{Quantity}_{\text{baseline fuel}} \text{ X } \text{EF}_{\text{baseline fuel}}$$

And:

$$\text{Emissions}_{\text{fuel extraction and processing}} = \text{Quantity}_{\text{baseline fuel}} \text{ X EF}_{\text{extraction and processing}}$$

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

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

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

Depending on the fuel type, fuel blending and electricity generation may be excluded.

Appendix E provides combined upstream and combustion emission factors for gasoline and diesel that incorporates the Alberta Renewable Fuels Standard. These emissions factors must be used.

4.2.1 Emissions $_{\text{upstream}}$

Upstream emissions include all emissions upstream of combustion, including 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 using an **estimated** quantity of baseline fuel. This quantity of baseline fuel is estimated using measures of service provided per unit of baseline fuel incorporated in the static historic baseline. Fuel extraction and processing can be quantified separately or combined with the other included upstream sources using emission factors from GHGenius (or other approved sources) as described in Appendix E.

If fuel blends are being used, fuel extraction and processing emissions for <u>each type of fuel</u> in the blend must be quantified separately and added together.

4.2.1.2 B2 - Fossil fuel blending

Greenhouse gas emissions associated with fossil fuel blending are not included in fuel extraction and processing emissions, and must be quantified separately. If blending does not occur in the baseline, this source is excluded from the quantification. Justification for the exclusion must be provided in the offset project plan.

The emissions for fossil fuel blending are determined using the same quantity 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 used as a fuel in the baseline condition, then it must be included in the baseline quantification reported as kWh per unit of service or productivity. If electricity is not used as a fuel in the baseline, this source is excluded from baseline quantification. Justification for the exclusion must be provided in the offset project plan.

Electricity used in the baseline is assumed to be generated by a mix of sources on the Alberta transmission grid and must be quantified using grid average electricity values published by Alberta Environment and Sustainable Resource Development. Site specific emission factors may be used if electricity is produced on site and directly sourced by the project (i.e. does not go on to the Alberta transmission grid). Further guidance is provided in the Technical Guidance for Offset Project Developers.

The amount of electricity used reported in kWh is determined in the same manner as fossil fuel using the historic baseline.

4.2.1.4 B4 - Fuel storage and dispensing

Emissions for fuel storage and dispensing are quantified using the same quantity of fuel estimated for B1 and B2. The energy required per unit of fuel dispensed is 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 E. Reminder, it is recommended that the combined emission factors provided in Appendix E for baseline fuels (e.g., diesel and gasoline) be used to quantify baseline emissions. If alternate emission factors are used, justification must be provided in the offset project plan.

This source also includes estimates of fugitive emissions. Fugitive emissions may be excluded from baseline fuel storage and dispensing if:

- The combined emission factor (which includes fugitive emissions) for fuel feedstocks is used, (See Appendix E) and;
    - It can be demonstrated that fugitive emissions from dispensing are similar in magnitude to the project condition fugitive emissions, or
    - Fuel dispensing is not controlled by the project developer[2] (emissions associated with fuel dispensing are then assumed to be neutral).

[2] In situations where baseline refuelling was not directly controlled by the project developer, it may be difficult to obtain suitable data to quantify these emissions. It is conservative to exclude this source from the baseline quantification, but still include it in the project emissions calculations.

4.2.2 B5 - Fuel combustion

The quantity of baseline fuel combusted is estimated using the same quantity of fuel used in B1, B2, and B4. Emissions are calculated as the quantity of fuel multiplied by the fuel specific emission factor provided in Appendix E.

If fuel blends, or multiple fuel types are included in the baseline (e.g., dual fuel or multi fuel engines), the combustion emissions for each fuel type are quantified separately and added together.

4.3 Project Condition Quantification

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

Where:

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

$$\text{Emissions}_{\text{fuel combustion}} = \text{Quantity}_{\text{project fuel}} \text{ X } \text{EF}_{\text{project fuel}}$$

And:

$$\text{Emissions}_{\text{fuel extraction and processing}} = \text{Quantity}_{\text{project fuel}} \text{ X } \text{EF}_{\text{extraction and processing}}$$

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

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

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

Default methodology prescribed in this protocol requires the use of combined upstream emission factors. Depending on the fuel type, fuel blending and electricity generation may be excluded.

4.3.1 Emissions $_{\text{upstream}}$

Upstream emissions includes all emissions upstream of combustion, including 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 using the **measured** quantity of project fuel. The quantity of project fuel is 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 using emission factors from GHGenius (or other approved sources) provided in Appendix E.

If fuel blends are used, the emissions from fuel extraction and processing for each type of fuel in the blend must be quantified separately and added together.

4.3.1.2 P2 - Fossil fuel blending

Fossil fuel blending emissions are calculated separately from fuel extraction and processing emissions. This source includes on-site blending of custom fuels or gasses specific to the project. Additional fuel blending may also occur on site, or at the mobile equipment just prior to combustion.

If fossil fuel blending is used, the additional energy used to combine and blend the fuels together must be quantified and included in project emissions. If blending is not applicable to this project, this source is excluded Justification for the exclusion must be described in the project plan.

The emissions for fossil fuel blending are determined using the same measured quantity of fuel used in P1 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

Electricity used in the project condition **must** be measured. The amount of electricity expressed in kWh is established using power purchase records, or directly through metering. If electricity is used as a fuel in the project and is not generated onsite for use in fuel storage and dispensing (e.g., onsite natural gas compression), this source is excluded from the project emissions quantification. Justification for the exclusion must be provided in the offset project plan.

Electricity used in the project is assumed to be generated by a mix of sources on the Alberta transmission grid and must be quantified using grid average electricity values published by Alberta Environment and Sustainable Resource Development. Site specific emission factors may be used if electricity is produced on site and directly sourced by the project (i.e. does not go on to the Alberta transmission grid). Further guidance is provided in the Technical Guidance for Offset Project Developers

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 using emission factors provided in GHGenius (or other approved sources) as described in Appendix E.

Emissions for fuel storage and dispensing, including compression and liquefaction of natural gas and other fuel feedstocks, are quantified using total metered energy used to dispense the fuel. Units for compression and liquefaction activities are project specific and may use units other than kWh (e.g., CO_2e per unit of fuel dispensed), particularly when fuel is provided by a commercial facility under contract from a third party. These alternate emission factors must be documented in the offset project plan, and are subject to third party verification.

P4 includes estimated fugitive emissions. Quantification of fugitive emissions is measured as the difference between the volume deposited into a storage tank and the volume dispensed from the tank

Fugitive emissions may be excluded from fuel storage and dispensing if:

- Combined emissions factors provided in Appendix E are used, which include fugitive emissions:
    - It can be demonstrated that fugitive emissions from dispensing are similar or less than baseline fugitive emissions, or
    - Fuel dispensing is not controlled by the project developer (emissions associated with fuel dispensing are assumed to be neutral).
- Fuel quantity is measured as the total corrected amount dispensed, not as received by the project vehicles where
    - Corrected dispensed amount includes adjustments for losses at storage/refueling facilities,
    - Adjustment = quantity fuel supplied - quantity fuel dispensed.

Records of fuel supplied to the refuelling station and of fuel dispensed from the station must used to substantiate the exclusion of fugitive emissions. These records are also used to determine an amount of fuel added to the project (i.e., fugitive fuel adjustment).

If fuel dispensing is not controlled by the project, emission factors provided in Appendix E must be used. If the fuel source is not included in GHGenius emission factors provided, manufacturer estimates of fugitive emissions associated with the refuelling technology can be used. Justification must be provided in the offset project plan.

4.3.2 P5 - Fuel combustion

The quantity of project fuel combusted is calculated using the measured manually of fuel used in P1 and P2. It is assumed that all fuel is combusted.

Emissions are calculated as the quantity of fuel multiplied by the appropriate fuel emission factor (See Appendix E).

If fuel blends, or multiple fuel types, are included in the project (e.g., dual fuel or multi fuel engines), the emissions for each fuel type must quantified separately and added together.

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: $Emissions_{upstream} = Emissions_{fuel\ extraction\ and\ processing} + Emissions_{fossil\ fuel\ blending} + Emissions_{electricity\ generation} + Emissions_{fuel\ storage\ and\ dispensing}$ $Emissions_{fuel\ combustion} = Quantity_{baseline\ fuel}\ X\ EF_{baseline\ fuel}$						
B1* Fuel extraction and processing	$Emissions_{fuel\ extraction\ and\ processing} = Quantity_{baseline\ fuel}\ X\ EF_{extraction\ and\ processing}$					
	$Quantity_{baseline\ fuel}$	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 must be identical to services supplied in the baseline historic baseline or performance standard.
	$EF_{extraction\ and\ processing}$	gCO_2e 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 source/sink, periodic updates are all that is available. Must use most recent version of GHGenius or other approved source.
B2*	$Emissions_{fossil\ fuel\ blending} = (\sum Quantity_{blended\ fuel})\ X\ Energy_{per\ unit\ volume\ blended}\ X\ EF_{energy}$					

Source/Sink	Parameter / Variable	Unit	Measured/ Estimated	Method	Frequency	Justify measurement or estimation and frequency
Fossil fuel blending	***Quantity*** $_{blended\ fuel}$	Litres, m^3, or kg	Estimated	Quantity of each constituent fuel in the blend is calculated proportionally from the total estimated baseline fuel.	Annually	This source/sink is only included if it occurred in the baseline. The quantity would be estimated from the quantity of baseline fuel calculated using a historic benchmark or performance standard baseline. Must be calculated annually during the project credit period.
	Energy $_{per\ unit\ volume\ blended}$	kWh per unit of fuel blended	Measured or estimated	From records of energy required to blend the constituent types together.	Periodic	Reviewed periodically when technology or process changes occur.
	EF $_{energy}$	CO_2e 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 AESRD and is periodically reviewed. Must use most recent AESRD 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*** $_{electricity\ generation}$ ***= Baseline kWh X EF*** $_{electricity}$					
	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
	***EF** electricity*	CO_2e 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 AESRD and is periodically reviewed. Must use most recent AESRD 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	***Emissions** fuel storage and dispensing **= (Energy** dispensing **X EF** energy**) + (Quantity** fugitive emissions **X EF** baseline fuel**)***					
	***Energy** dispensing*	kWh	Estimated	From records of energy required to dispense baseline fuel (historic baseline), 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 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.
	***EF** energy*	CO_2e 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 AESRD and is periodically reviewed. Must use most recent AESRD 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
	Quantity $_{fugitive\ emissions}$	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 quantity 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. Emissions factors for dispensing are periodically updated for Alberta in GHGenius. Must use most recent version of GHGenius or other approved source.
	EF $_{baseline\ fuel}$	CO_2e per unit of fuel	Estimated	From Environment Canada or other approved Alberta source.	Periodic	Must use most current approved emission factor for Alberta. Appendix C provides emissions factors including Alberta RFS.
B5 Fuel combustion	***Emissions*** $_{fuel\ combustion}$ = ***Quantity*** $_{baseline\ fuel}$ ***X EF*** $_{baseline\ fuel}$					
	Quantity $_{baseline\ fuel}$	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 $_{baseline\ fuel}$	CO_2e per unit of fuel combusted	Estimated	From Environment Canada reference documents.	Annually	Must use most current approved emission factor for Alberta. Appendix E provides emissions factors including Alberta RFS.

Source/Sink	Parameter / Variable	Unit	Measured/ Estimated	Method	Frequency	Justify measurement or estimation and frequency
Project Condition $Emissions_{Project} = Emissions_{upstream} + Emissions_{fuel\ combustion}$ Where: $Emissions_{upstream} = Emissions_{fuel\ extraction\ and\ processing} + Emissions_{fossil\ fuel\ blending} + Emissions_{electricity\ generation} + Emissions_{fuel\ storage\ and\ dispensing}$ $Emissions_{fuel\ combustion} = Quantity_{project\ fuel}\ X\ EF_{project\ fuel}$						
P1* Fuel extraction and processing	$Emissions_{fuel\ extraction\ and\ processing} = Quantity_{project\ fuel}\ X\ EF_{extraction\ and\ processing}$					
	$Quantity_{project\ fuel}$	Litres, m^3, or kg	Measured	Metered Quantity and or fuel purchase records.	Annually	The amount of project fuel is a direct measure of fuel used annually during the project credit period.
	$EF_{extraction\ and\ processing}$	gCO_2e 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 source/sink, periodic updates are all that is available. Must use Appendix E that incorporates the most recent version of GHGenius, or other approved source.
P2* Fossil fuel blending	$Emissions_{fossil\ fuel\ blending} = (\sum Quantity_{blended\ fuel})\ X\ Energy_{per\ unit\ volume\ blended}\ X\ EF_{energy}$					
	$Quantity_{blended\ fuel}$	Litres, m^3, or kg	Measured	Quantity of each constituent fuel in the blend is calculated proportionally from the total project fuel Quantity 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.

Source/Sink	Parameter / Variable	Unit	Measured/ Estimated	Method	Frequency	Justify measurement or estimation and frequency
	***Energy** per unit volume blended*	kWh per unit of fuel blended	Estimated	From records of energy required to blend the constituent fuel types together.	Periodic	Reviewed periodically when technology or process changes occur.
	***EF** energy*	CO_2e 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 AESRD and is periodically reviewed. Must use most recent AESRD 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	***Emissions** electricity generation **= Project kWh X EF** electricity*					
	Project kWh	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 greenhouse gas 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.
	***EF** electricity*	CO_2e 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 AESRD and is periodically reviewed. Must use most recent AESRD 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
P4* Fuel storage and dispensing**	***Emissions*** $_{fuel\ storage\ and\ dispensing}$ **= (*Energy*** $_{dispensing}$ ***X EF*** $_{energy}$**) + (*Quantity*** $_{fugitive\ emissions}$ ***X EF*** $_{project\ fuel}$**)**					
	Energy $_{dispensing}$	kWh, GJ, fuel unit	Measured or from reported values	Measured directly or from records of reported energy required to dispense project fuel.	Periodic	Measured energy use must be used. If the dispensing equipment is not controlled by the project developer then it may be estimated from reported energy use and quantity of fuel dispensed. Any additional emissions for modification of natural gas feedstock (e.g., compression or liquefaction) are included with this source.
	EF $_{energy}$, ***EF*** $_{compression}$, ***EF*** $_{liquefaction}$	CO_2e per unit	Estimated	From approved Alberta emission factor source.	Periodic	Emission factor for electric power supplied from the Alberta grid is provided by AESRD and is periodically reviewed. Must use most recent AESRD emission factor or an approved project-specific emission factor if energy is supplied from a source other than the Alberta electric grid. Other emission factors may be project specific but must use Alberta approved sources and are subject to verification.

Source/Sink	Parameter / Variable	Unit	Measured/ Estimated	Method	Frequency	Justify measurement or estimation and frequency
	***Quantity** $_{fugitive\ emissions}$*	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 Quantity 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 may be used.
	***EF** $_{project\ fuel}$*	CO_2e per unit of fuel	Estimated	From Environment Canada or other approved Alberta source.	Periodic	Must use most current approved emission factor for Alberta. Appendix E provides emissions factors including Alberta RFS.
P5 Fuel combustion	***Emissions** $_{fuel\ combustion}$ **= Quantity** $_{project\ fuel}$ **X EF** $_{project\ fuel}$*					
	***Quantity** $_{project\ fuel}$*	Litres, m^3, GJ or kg	Measured	Metered Quantity and or fuel purchase records.	Annually	The amount of project fuel is measured directly for each year during the project credit period.
	***EF** $_{project\ fuel}$*	CO_2e per unit of fuel combusted	Estimated	From Environment Canada reference documents.	Annually	Must use most current approved emission factor for Alberta. Appendix E provides emissions factors including Alberta RFS.

* Note: The preferred method is that upstream emissions be quantified together using combined emission factors from approved Alberta sources. These sources/sinks are provided here separately for completeness and to facilitate projects where they are separate (e.g., onsite compression or processing).
** May be broken into fuel feedstock and onsite sources/sinks, each require separate quantification (e.g., onsite natural gas compression requires quantification for the natural gas feedstock to the compression facility and a second quantification for compression and dispensing of CNG).

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 any subsequent government audits.

The project developer must establish and apply quality management procedures to manage data and information. Written procedures must be established for each measurement task outlining responsibility, timing and 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;
    - Proof of service delivery and fuel consumption related to that service within Alberta.
- The alternative fuel consumed in the project is not industry standard practice;
- Project is not required by law; and
- The emission reductions claimed are owned by the project developer by proof of fuel and technology purchases.

5.1.2 Project Quantification Documentation

Project documentation includes:

- Level of service including:
    - Distance travelled using 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.
- Quantity of fuel consumed in mobile equipment using metered dispensing and/or proof of purchase of fuel.

5.1.3 Baseline Condition Documentation

Three years of historical data are required for historic and expansion projects. Baseline documentation includes:

- Level of service including:
    - Distance travelled using 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 using metered energy consumption and/or proof of purchase of energy.
- Quantity of fuel consumed in mobile equipment using metered dispensing and/or proof of purchase of fuel.

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

- Description of sampling design and criteria used;
- Sampling results, including summary statistics;
- Rational for decision made based on the sampling results; and
- If used, third party validation of methods used and results obtained.

5.2 Record Keeping

AESRD 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.

Table 6: Minimum Recrd-Keeping Requirements.

Data Requirement	Examples of Acceptable Records Description	Why it is Required
Fuel use (baseline and project)	Commercial grade meter of fuel and/or power dispensed or used. Purchase records for fuel and/or power.	Quantification and verification
Measurement equipment	Description of meters used and calibration records or standards of calibration. Meter model number, serial number, and manufacturer's calibration procedures. For commercial purchases, proof of commercial grade metering from the supplier is required.	Verification
Map or other proof of location	Map or description showing location of fuel purchase and use in Alberta. May include: GIS tracking logs, truck logbooks or onboard computer data, location maps such as city boundaries, forest harvest unit or section location.	Verification
Baseline calculations	Three years of raw data in database and/or spreadsheet format. If sampling was used, require also summary statistics and methods used to calculate statistics. A record of all adjustments made to raw baseline data with justifications.	Quantification and verification
Project calculations	Raw data and calculations in database and/or spreadsheet format.	Quantification and verification
Proof of purchase or modification date for project vehicle	Dated commercial transaction records and description of modification or purchase requirements.	Verification
All calculations of greenhouse gas emissions/reductions and emission factors used	Spreadsheet format or hardcopy with formula and emission factors included.	Quantification and verification

In order to support the third party verification, 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. AESRD reserves the right to audit offset credits and associated projects submitted to AESRD 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 http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php

Specified Gas Emitters Regulation. Climate Change and Emissions Management Act. Alberta Queen's Printer. Available online: http://www.qp.alberta.ca/documents/Regs/2007_139.pdf

Technical Guidance for Offset Protocol Developers. Version 1.0. January 2011. Available online: http://carbonoffsetsolutions.climatechangecentral.com/offset-protocols/approved-Alberta-protocols

Technical Guidance for Offset Project Developers. Version 2.0. January 2011. Available online: http://carbonoffsetsolutions.climatechangecentral.com/offset-protocols/approved-alberta-protocols

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

The general equation for calculation of emission reductions is:

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

Where:

$\text{Emissions}_{\text{Baseline}}$ = sum of the emissions included under the Baseline Condition.

$\text{Emissions}_{\text{Project}}$ = 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:

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

$$\text{Emissions}_{\text{fuel combustion}} = \text{Quantity}_{\text{baseline fuel}} \text{ X } \text{EF}_{\text{baseline fuel}}$$

And:

$$\text{Emissions}_{\text{fuel extraction and processing}} = \text{Quantity}_{\text{baseline fuel}} \text{ X } \text{EF}_{\text{extraction and processing}}$$

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

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

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

Note: Gasoline and diesel should use the combined emission factors for upstream and combustion emissions including adjustments to include Alberta Renewable Fuel Standard requirements (See Appendix E).

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

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

Where:

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

$$\text{Emissions}_{\text{fuel combustion}} = \text{Quantity}_{\text{project fuel}} \text{ X } \text{EF}_{\text{project fuel}}$$

And:

$$\text{Emissions}_{\text{fuel extraction and processing}} = \text{Quantity}_{\text{project fuel}} \text{ X } \text{EF}_{\text{extraction and processing}}$$

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

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

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

Example: Project Scenario 1 - Mobile Source Simple Case with Combined Emission Factors

Project scenario: Ten new CNG public transportation busses are used to replace 10 diesel busses in a large urban system. In this example, CNG is purchased from a commercial facility.

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

Project plan: CNG is a lower greenhouse gas emission fuel compared to diesel fuel. The service provided (passenger capacity and distance traveled) and fuel used are measured in the project condition. This measure of services (i.e., passenger capacity and km) is used to estimate baseline fuel volume using a historic benchmark. This calculated fuel volume is used to estimate combustion and upstream emissions using approved emission factors.

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

A) Static Historic Baseline Calculations

During the project planning phase, the project developer establishes the historic baseline.

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

year	Litres	Passenger capacity	km traveled	Sample size
1	3400000	5000	8800000	100 busses
2	3500000	5000	8750000	100 busses
3	3300000	5000	8000000	100 busses

Total litres and total kilometers are divided by total busses (in this case, 100) to determine litres per passenger capacity km (L/Pcapkm).

year	Litres	Passenger capacity	km traveled
1	34000	50	88000
2	35000	50	87500
3	33000	50	80000

The Liters of diesel fuel consumed for each passenger capacity km (L per Pcap km) is calculated for each year as:

$$L/Pcapkm_{year} = Litres/(passenger\ capacity\ X\ km)$$

$$L/Pcapkm_{Year\ 1} = 34000/(50\ X\ 88000) = 0.0077$$

$$L/Pcapkm_{Year\ 2} = 35000/(50\ X\ 87500) = 0.0080$$

$$L/Pcapkm_{Year\ 3} = 33000/(50\ X\ 80000) = 0.0083$$

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

$$L/Pcapkm_{baseline} = (L/Pcapkm_{Year\ 1} + L/Pcapkm_{Year\ 2} + L/Pcapkm_{Year\ 3}) / 3$$

$$= 0.0080$$

Note: a monitoring program was not needed to collect additional data because three complete years of census data were available.

The baseline was created from a census of the entire bus fleet, not a representative sample. A confidence interval for the data was not calculated because a complete census is assumed to provide the true (actual) value.

Flexibility Mechanism 1: Establishing a baseline using statistical sampling or performance standards

In most situations, three years of complete census information will not be available to establish the baseline. Table A1 describes how statistical sampling is used to establish a historic baseline. Table A2 describes how to establish a performance standard baseline for new projects (e.g., new bus service or garbage pickup where none existed before).

The methods require that the lower bound of the 95th percentile confidence interval be used rather than the mean to ensure conservativeness in the baseline calculations.

While the method described in Table A1 below uses litres per passenger capacity km (L/Pcapkm) for busses, the methods described are applicable to all project types including units for transportation (L per tonnes hauled km), agriculture (L per area hour), and forest harvesting (L per harvest volume hr).

Table A1. Calculating Static Historic Baseline using a Subsample for Existing and Expansion Projects.

Alternate method for calculating historic benchmark using subsample
Issue: no census information or incomplete information is currently available.
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.
Step 2: for each of the selected busses monitor total fuel used and total km traveled over one full year.
Step 3: calculate the litres of fuel per passenger capacity km (L per Pcap km) for each bus.
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 establish what the historic baseline should be. The lower bound of the 95th percentile confidence interval must be used. This will ensure that the quantification meets the requirements to be conservative and not overestimate.

The subsample must contain a representative number of vehicles determined on a project specific basis.

Vehicle	Fuel (L)	Passenger capacity	km	Pcap km	L per Pcap km
1	32000	40	80900	3236000	0.009888752
2	36400	40	77200	3088000	0.011787565
3	33000	40	85000	3400000	0.009705882
4	32400	50	81000	4050000	0.008
5	32600	50	82000	4100000	0.00795122
6	33200	50	82400	4120000	0.008058252
7	35400	50	78000	3900000	0.009076923
8	33600	60	84000	5040000	0.006666667
9	29800	60	72500	4350000	0.006850575
10	31600	60	77000	4620000	0.006839827
Total	330000	500	800000	39904000	0.084825662

Sample size	10	This is the number of vehicles in the sample
Average	0.00848257	L/pcap km
STDEV	0.00163656	This is the standard deviation
Confidence interval	0.00101433	This is the 95% confidence interval
95% Upper bound	0.0094969	This is the upper bound of the 95% confidence interval
95% Lower bound	**0.00746824**	**This is the lower bound of the 95% confidence interval.**
		This is your historic baseline for determining baseline fuel volume

Table A2. Flexibility Mechanism for Developing a Static Performance Standard Baseline for New Projects.

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 a historic benchmark baseline using a subsample.
Plan Option 2: acquire a number of baseline vehicles and operate them under normal conditions in the project area and employ the methods described in establishing a historic benchmark baseline using a subsample.
Plan Option 3: obtain 3 years of existing data from a suitable analog community for the baseline activity.
Considerations: As with the historic benchmark sub sampling flexibility mechanism a statistically representative sample of fuel use and service provided must be collected. Additional considerations include: terrain and traffic densities are 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. For option 3 acquire and describe the source of the data.
Step 3: for options 1 and 2 follow the steps described for establishing a historic benchmark baseline using a subsample. For option 3 have the baseline data validated by a third party and or Alberta environment.
Step 4: for all options (1,2,3) 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 establish what the historic baseline value should be. 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.

B) Project start and monitoring

Initiate project and monitor the fuel use and distance travelled. After one full year of operation, the 10 CNG project busses resulted in the following data.

Bus #	kg CNG	Passenger capacity	km
1	6393.6	50	80,000
2	6233.8	50	78,000
3	6793.2	50	85,000
4	6473.5	50	81,000
5	6553.4	50	82,000
6	6633.4	50	83,000
7	7033.0	50	88,000
8	6713.3	50	84,000
9	5754.2	50	72,000
10	6313.7	50	79,000
Project Total	**64,895**	**500**	**812,000**

C) Baseline fuel quantity calculation (using the historic baseline)
The units for the quantity of fuel will depend on the fuel type used. It may be reported as a volume measured in litres or m^3, a weight measured in kilograms or tonnes, or a unit of energy such as kWh or joules. Units of fuel must be consistent between the baseline and project condition. The example below uses diesel fuel measured in litres.

If the project contains a small number of new vehicles, the baseline litres are estimated from the passenger capacity and km traveled for each vehicle using the historic benchmark from Part A as follows:

$$\text{Quantity}_{\text{baseline fuel}} = \sum (\text{project vehicle passenger cap X project vehicle km}) \text{ X } \text{L/Pcapkm}_{\text{baseline}})$$

Where:

project vehicle passenger cap = passenger capacity of each project vehicle

project vehicle km = km traveled by each vehicle(monitored during project)

$\text{L/Pcapkm}_{\text{baseline}}$ = 0.0080 (from historic baseline)

Buss #	Passenger capacity	km	Pcap km	L per Pcap km	Estimated fuel use (L)
1	50	80,000	4000000	0.008	**32000**
2	50	78,000	3900000	0.008	**31200**
3	50	85,000	4250000	0.008	**34000**
4	50	81,000	4050000	0.008	**32400**
5	50	82,000	4100000	0.008	**32800**
6	50	83,000	4150000	0.008	**33200**
7	50	88,000	4400000	0.008	**35200**
8	50	84,000	4200000	0.008	**33600**
9	50	72,000	3600000	0.008	**28800**
10	50	79,000	3950000	0.008	**31600**
	500	812,000	40,600,000		**324800**

For this example, the total baseline fuel use is 324800 L of diesel. This is the amount of diesel that would have been used by diesel busses in the baseline.

If the project contains a large number of replacement vehicles, baseline fuel can be calculated using the following formula.

$$\text{Quantity}_{\text{baseline fuel}} = (\text{average project passenger cap X total project km}) \text{ X } \text{L/Pcapkm}_{\text{baseline}}$$

Where:

Average project passenger cap = sum of the passenger capacity of all project busses/number of project busses

Total project km = sum of kilometers traveled by all project busses (monitored during project)

$L/Pcapkm_{baseline}$ = 0.0080 (from historic baseline)

$Quantity_{baseline\ fuel}$ = ((500/10) X 812,000) X 0.0080
= 324,800 L

This is the litres of baseline fuel (diesel) that would have been combusted in the absence of the project.

D) Baseline emissions calculations

Upstream and combustion emissions for the baseline are calculated as follows:

$$Emissions_{Baseline} = Emissions_{upstream} + Emissions_{fuel\ combustion}$$

Note: electricity emissions and fuel blending are not applicable in this example, and have been excluded.

$$Emissions_{upstream} = Emissions_{fuel\ extraction\ and\ processing} + Emissions_{fuel\ storage\ and\ dispensing}$$

Using the emission factor provided in Appendix E:.

$$Emissions_{Baseline} = Quantity_{baseline\ fuel} \text{ X } EF_{combined\ baseline\ diesel\ fuel}$$

Where:

$Quantity_{baseline\ fuel}$ = 324,800 L

$EF_{combined\ baseline\ diesel\ fuel}$ (CO_2e) = 3674.5 g/L (includes RFS, combustion and upstream of combustion)

Where:

$Emissions_{Baseline}$ = 324,800 L X 3674.5 g/L

$Emissions_{Baseline}$ = 1,193,477,600 g CO_2e

= 1193.5 tonnes CO_2e (divide by 1,000,000 to get tonnes)

E) Project emissions calculation

Project emissions are calculated using direct measurements of fuel and energy used:

$$Emissions_{Project} = Emissions_{upstream\ project} + Emissions_{fuel\ combustion\ project}$$

Fuel combustion emissions are calculated using measured CNG combusted multiplied by the emission factors for natural gas provided in Appendix E.

$$\text{Emissions}_{\text{fuel combustion project}} = \text{Quantity}_{\text{project fuel}} \text{ X } \text{EF}_{\text{project fuel}}$$

Reminder, the project and baseline must use the same units. If unit conversions are required, the factors and assumptions used to convert the units must be included in the offset project plan.

$$\text{Emissions}_{\text{fuel combustion project}} = 64{,}895 \text{ kg X } 2760.6 \text{ g/kg } CO_2e$$

$$\text{Emissions}_{\text{fuel combustion project}} = 179{,}149{,}000 \text{ g } CO_2e$$

$$= 179.1 \text{ tonnes } CO_2e$$

Upstream emissions for compression of the natural gas and for onsite storage and/or dispensing of the compressed gas vary by project. As such, appropriate emission factors must be used for the different activities.

Note: Fuel blending and electricity are excluded from this example.

Upstream project emissions are:

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

Where:

$\text{Emissions}_{\textit{fuel extraction and processing}}$ = Emissions from extraction, processing and delivery of the natural gas to the CNG refueling facility.

$\text{Emissions}_{\text{fuel storage and dispensing}}$ = Emissions to compress, store and dispense the natural gas at the CNG refuelling facility.

Appendix E provides the upstream emission factor (in units of CO_2e) for the natural gas feedstock as 433.6 g/kg:

$$\text{Emissions}_{\text{fuel extraction and processing}} = 64{,}895 \text{ kg X } 433.6 \text{ g/kg } CO_2e$$

$$\text{Emissions}_{\text{fuel extraction and processing}} = 28{,}138{,}472 \text{ g } CO_2e$$

$$= 28.1 \text{ tonnes } CO_2e$$

In this example the project is purchasing its CNG from a commercial facility that is not under the control of the project developer. The commercial CNG refueling facility reports its energy to compress and dispense CNG. This information would be required to calculate storage and dispensing emissions. Note: the reported energy use and kg dispensed must be from commercial grade meters.

The energy use reported is 3 kWh to compress and dispense 1 kg of natural gas. This is equivalent to 0.003 MWh/kg of natural gas.

Electricity emissions are calculated using the Alberta grid intensity factor set at 0.882 tCO_2e/MWh for electricity use in Alberta[3].

Value	Units	Description
3	kWh/kg	Reported from commercial refuelling facility (not project controlled)
0.003	MWh/kg	Conversion from kWh to MWh per kg of natural gas dispensed
0.882	tCO_2e/MWh	Grid Emission factor (from Alberta Environment)
0.002646	tCO_2e/kg	(MWh/kg X tCO_2e/MWh). Tonnes CO_2e per kg of natural gas dispensed

$$\text{Emissions}_{\text{fuel storage and dispensing}} = 64{,}895 \text{ kg X } 0.002646 \text{ tonnes } CO_2e/\text{kg}$$
$$= 171.7 \text{ tonnes } CO_2e$$

Note: the value 0.002646 tonnes CO_2e/kg used above is a project specific emission factor for compression and dispensing of fuel. This value must be recalculated as required throughout the lifetime of the project.

Project upstream emissions are the sum of the emissions from extraction and processing of the natural gas feedstock, compression, and storage and dispensing of the natural gas at the CNG refueling facility.

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

$$\text{Emissions}_{\text{fuel extraction and processing}} = 28.1 \text{ tonnes } CO_2e$$

$$\text{Emissions}_{\text{fuel storage and dispensing}} = 171.7 \text{ tonnes } CO_2e$$

$$\text{Emissions}_{\text{upstream project}} = 28.1 + 171.7$$
$$= 199.8 \text{ tonnes } CO_2e$$

The upstream project emissions are added to the combustion emissions to get total project emissions.

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

$$\text{Emissions}_{\text{upstream project}} = 199.8 \text{ tonnes } CO_2e$$

$$\text{Emissions}_{\text{fuel combustion project}} = 179.1 \text{ tonnes } CO_2e$$

$$\text{Emissions}_{\text{Project}} = 199.8 + 179.1$$
$$= 378.9 \text{ tonnes } CO_2e$$

[3] Contact Alberta Environment to obtain the most recent energy emission factors.

F) Emission Reduction Calculation

Emission reductions achieved by the project are calculated as follows:

$$\text{Emission Reduction} = \text{Emissions}_{\text{Baseline}} - \text{Emissions}_{\text{Project}}$$
$$\text{Emissions}_{\text{Baseline}} = 1193.5 \text{ tonnes } CO_2e$$
$$\text{Emissions}_{\text{Project}} = 378.9 \text{ tonnes } CO_2e$$

$$\textbf{Emission Reduction} = \mathbf{1193.5 - 378.9}$$
$$= \mathbf{814.6 \text{ tonnes } CO_2e}$$

Appendix B Example of Baseline and Project Condition Calculations with Onsite Natural Gas Compression

Example 2. Project Scenario 2 - Mobile Source with On-site Fuel Compression

This example will use the same conditions as Example 1 above except that onsite compression of natural gas has been included in the project.

Project scenario: Ten diesel busses are replaced by 10 new CNG busses in large urban system. The busses are fueled from a dedicated (controlled) 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 compared to diesel fuel. The service provided (passenger capacity and distance traveled) and fuel used are measured in the project condition. This measure of services (i.e., passenger capacity and km) is used to estimate baseline fuel volume using a historic benchmark. This calculated fuel volume is used to estimate combustion and upstream emissions using approved emission factors.

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

A) Historic Baseline Calculations

During the project planning phase, the project developer must establish a historic baseline. The 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 capacity	km traveled	Sample size
1	3400000	5000	8800000	100 busses
2	3500000	5000	8750000	100 busses
3	3300000	5000	8000000	100 busses

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

$L/Pcapkm_{baseline} = 0.0080$ (see example 1 for calculations)

B) Project start and monitoring

Project performance and monitoring for 10 CNG busses resulted in the following data (unchanged from example 1):

Bus #	kg CNG	Passenger capacity	km
1	6393.6	50	80,000
2	6233.8	50	78,000
3	6793.2	50	85,000
4	6473.5	50	81,000
5	6553.4	50	82,000
6	6633.4	50	83,000
7	7033.0	50	88,000
8	6713.3	50	84,000
9	5754.2	50	72,000
10	6313.7	50	79,000
Project Total	**64,895**	**500**	**812,000**

Unlike in example 1, natural gas compression was done onsite. Therefore, the energy required to operate the compression and refueling station was also monitored with a commercial grade meter.

Total CNG refueling facility energy use for the project quantification year was 129,790 kWh based on meter readings.

C) Baseline fuel quantity calculation (using the historic baseline)

Calculate the baseline emissions for combustion (same as example 1).

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

This is the litres of baseline fuel (diesel) that would have been combusted in the absence of the project.

D) Baseline emission calculations

Use the calculated baseline fuel volume to determine upstream baseline emissions (see example 1).

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

Where:

$$\text{Emissions}_{\text{Baseline}} = \text{Quantity}_{\text{baseline fuel}} \text{ X } \text{EF}_{\text{combined baseline diesel fuel}}$$

$$\text{Emissions}_{\text{Baseline}} = 324{,}800 \text{ L X } 3674.5 \text{ g/L}$$

Emissions $_{\text{Baseline}}$ = 1193.5 tonnes CO_2e (divided by 1,000,000 to convert grams to tonnes)

E) Project Emissions Calculation

Project emissions are calculated using measured data. Note: emissions from fossil fuel blending and electricity generation are excluded from this example (See example 1).

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

Where:

$$\text{Emissions}_{\text{fuel combustion project}} = \text{Quantity}_{\text{project fuel}} \text{ X } \text{EF}_{\text{project fuel}}$$

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

Combustion emissions are calculated using emission factors provided in Appendix E (See example 1)..

$$\text{Emissions}_{\text{fuel combustion project}} = \text{Quantity}_{\text{project fuel}} \text{ X } \text{EF}_{\text{project fuel}}$$

$$\text{Emissions}_{\text{fuel combustion project}} = 64{,}895 \text{ kg X } 2760.6 \text{ g/kg } CO_2e$$

$$\text{Emissions}_{\text{fuel combustion project}} = 179.1 \text{ tonnes } CO_2e$$

Unlike Example 1, natural gas is compressed onsite. As such, the energy required for compression and dispensing 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 and quantified separately.

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

Where:

Emissions $_{\text{fuel extraction and processing}}$ = Emissions from extraction, processing and delivery of the natural gas to the CNG refueling facility.

Emissions $_{\text{fuel storage and dispensing}}$ = Emissions to compress, store and dispense the natural gas at the CNG refuelling facility.

Appendix E provides the upstream emission factor (433.6 g/kg CO_2e) for the natural gas feedstock and describes the sources included in the emission factor.

$$\text{Emissions}_{\text{fuel extraction and processing}} = 64{,}895 \text{ kg X } 433.6 \text{ g/kg } CO_2e$$

$$\text{Emissions}_{\text{fuel extraction and processing}} = 28.1 \text{ tonnes } CO_2e$$

Fuel storage and dispensing is calculated from metered energy required to compress and dispense the compressed natural gas. Both the energy used and the amount of fuel dispensed must be metered using commercial grade meters.

In this example, the refuelling facility is a dedicated source controlled by the project. The required data collected for this example is shown below:

	Value	Unit	Description
A	129790	kWh	Facility energy use (includes compression and dispensing)
B	64895	kg	Kilograms of natural gas dispensed
A/B	2	kWh/kg	kWh per kg of natural gas dispensed
C = (A/B)/1000	0.002	MWh/kg	Conversion from kWh to MWh per kg of natural gas dispensed
D	0.882	tCO2e/MWh	Grid Emission factor (from Alberta Environment)
E = C X D	0.001764	tCO2e/kg	(MWh/kg X tCO_2e/MWh). Tonnes CO_2e per kg of natural gas dispensed

In this example, fuel was only supplied to the project. Therefore, the emissions are calculated directly from the energy used (row A) multiplied by the Alberta grid emission factor (row D).

$$\text{Emissions}_{\text{fuel storage and dispensing}} = (129790 \text{ kWh} / 1000 \text{ kWh/MWh}) \text{ X } 0.882 \text{ tCO}_2\text{e per MWh}$$

$$\text{Emissions}_{\text{fuel storage and dispensing}} = 114.5 \text{ tonnes CO}_2\text{e}$$

Note: if the refuelling facility had supplied fuel to vehicles other than the project vehicles, the same approach used in example would have been used in this example; the tonnes CO_2e per kg of natural gas fuel dispensed would have been used (row E). For example:

$$\text{Emissions}_{\text{fuel storage and dispensing}} = \text{Quantity}_{\text{project fuel}} \text{ X tCO}_2\text{e per kg natural gas dispensed}$$

$$\text{Emissions}_{\text{fuel storage and dispensing}} = 64895 \text{ kg X } 0.001764 \text{ tCO}_2\text{e/kg}$$

$$\text{Emissions}_{\text{fuel storage and dispensing}} = 114.5 \text{ tonnes CO}_2\text{e}$$

Row E represents a project specific emission factor for compression and dispensing of fuel that must be recalculated as required throughout the lifetime of the project.

Once completed the upstream project emissions are added together:

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

$$\text{Emissions}_{\text{fuel extraction and processing}} = 28.1 \text{ tonnes CO}_2\text{e}$$

$$\text{Emissions}_{\text{fuel storage and dispensing}} = 114.5 \text{ tonnes CO}_2\text{e}$$

$$\text{Emissions}_{\text{upstream project}} = 28.1 + 114.5 = 142.6 \text{ tonnes } CO_2e$$

Next, the project emissions from upstream and combustion are added together to get the total project emissions.

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

$$\text{Emissions}_{\text{upstream project}} = 142.6 \text{ tonnes } CO_2e$$

$$\text{Emissions}_{\text{fuel combustion project}} = 179.1 \text{ tonnes } CO_2e$$

$$\text{Emissions}_{\text{Project}} = 142.6 + 179.1$$

$$= 321.7 \text{ tonnes } CO_2e$$

F) Emission Reduction Calculation

The final step is to calculate the emission reduction achieved by the project.

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

$$\text{Emissions}_{\text{Baseline}} = 1193.5 \text{ tonnes } CO_2e$$

$$\text{Emissions}_{\text{Project}} = 321.7 \text{ tonnes } CO_2e$$

$$\mathbf{Emission\ Reduction = 1193.5 - 321.7}$$

$$\mathbf{= 871.8\ tonnes\ CO_2e}$$

Appendix C Example Calculations for Forest Harvesting Equipment Using a Subsample (Flexibility Mechanism 1)

Example 3: Changes in forest harvesting equipment using a subsample (flexibility mechanism 1)

Project scenario: A forest company is seeking to reduce its greenhouse gas emissions by switching from diesel fuel to LNG in its portable chipping operations. The portable chipper is located in the harvest block replacing centralized chipping at the mill. LNG is supplied to the chipper from temporary storage tanks supplied under contract from a third party.

Baseline scenario (BAU case): Continued use of diesel fuel.

Project plan: Services provided in the project are reported as the cubic meters of trees chipped per hour of operation per unit of fuel used of the portable chipper. Diesel used on the baseline is being replaced with LNG, which is a lower greenhouse gas emission fuel.

Three years of census data for chipper operations is not available. The baseline will be established using a measured data for a subsample of the project to estimate the baseline fuel use used to establish the historic baseline. This estimated fuel volume will be used to estimate emissions from upstream and combustion using approved emission factors provided in Appendix E.

Calculations. The example calculations are broken down into steps explained in parts A through F.

A) Baseline Historic Calculations

Three years of census data was not available to establish a historic baseline. Flexibility mechanism 1 was used, which allows emissions to be estimated using a subsample of the population. Subpopulation data was collected across the range of operating conditions present in the project developer's management area.

A preliminary assessment was done to determine which parameters had the greatest effect on chipper operation. This information informed the selection of the sample size. Based on the initial assessment, it was determined that the size of the trees is the only significant factor influencing fuel use efficiency. A sample size of 30 harvest blocks was required to reach the required level of accuracy.

A baseline sampling plan was developed that included stratification for size of tree for 30 harvest blocks. the three size strata are weighted to reflect the harvest schedule.

The following data was collected for the 30 harvest blocks included in the sample:

	Data collected in the field			Calculations		
Block #	**m^3**	**hr**	**L**	**m^3/hr**	**L/hr**	**L/m^3**
Block 1	1210	21	2473	57.619	117.762	2.044
Block 2	1790	33	3058	54.236	92.667	1.709
Block 3	2110	37	4175	57.035	112.838	1.978
Block 4	850	13	1213	65.385	93.308	1.427
Block 5	2273	43	4530	52.858	105.349	1.993
Block 6	3537	62	7098	57.044	114.484	2.007
Block 7	1700	27	3790	62.966	140.370	2.229
Block 8	1676	28	3196	59.869	114.143	1.907
Block 9	690	12	1156	57.482	96.333	1.676
Block 10	816	14	1332	58.258	95.143	1.633
Block 11	1642	29	2582	56.620	89.034	1.572
Block 12	1068	17	2147	62.796	126.294	2.011
Block 13	8025	143	17450	56.119	122.028	2.174
Block 14	850	12	2149	70.792	179.083	2.530
Block 15	2284	39	4520	58.559	115.897	1.979
Block 16	716	13	1425	55.084	109.615	1.990
Block 17	2510	43	5146	58.374	119.674	2.050
Block 18	739	15	1469	49.240	97.933	1.989
Block 19	3250	57	7114	57.018	124.807	2.189
Block 20	2745	48	6025	57.178	125.521	2.195
Block 21	9450	167	14923	56.584	89.359	1.579
Block 22	2817	49	6905	57.487	140.918	2.451
Block 23	8272	145	16009	57.046	110.407	1.935
Block 24	2952	54	5975	54.663	110.648	2.024
Block 25	5327	93	11683	57.281	125.624	2.193
Block 26	4236	74	6578	57.247	88.892	1.553
Block 27	3238	57	5145	56.807	90.263	1.589
Block 28	10265	180	19830	57.029	110.167	1.932
Block 29	21254	372	42149	57.134	113.304	1.983
Block 30	14911	260	32017	57.351	123.142	2.147
Total	**123200.3**	**2157**	**243262**			**58.670**

Sample size (n)	30
Sample mean	1.956
Sample standard deviation	0.266
95% Confidence interval	0.095
Lower bound of the 95% confidence interval	**1.861**

Units of litres of diesel fuel consumed per m^3 of trees processed by the chipper (L/m^3) were calculated for each of the 30 sample blocks.

Summary statistics were then calculated from the sample data as described in the flexibility mechanism (See Table A1 in Appendix A) using the lower bound of the 95% confidence interval. For this example the lower bound of the 95% confidence interval is 1.861 L/m^3.

B) Project start and monitoring

After one full year of monitoring, the LNG converted chipper was used on 50 harvest blocks and processed a total of 205,400 m^3. The amount of LNG fuel used for the year was 567,611 L equivalent to 13,622.7 GJ of energy using a high heating value (HHV) conversion of 24 MJ/L. Note, the location of each of the blocks was recorded for inclusion in the offset project report.

Project Summary Data	
Blocks	50
m^3	205,400
LNG (L)	567,611
LNG (GJ)	13,622.7

C) Baseline fuel quantity calculation

The quantity of baseline fuel combusted (volume of fuel that would have been combusted under the baseline condition) was calculated using the value 1.861 Litres of diesel fuel for every cubic meter processed determined in part A.

$$\text{Quantity}_{\text{baseline fuel}} = \sum (\text{Project } m^3 \text{ processed}) \text{ X } L/m^3{}_{\text{baseline}}$$

Where:

Project m^3 processed = 205,400 (the total annual m^3 processed by the chipper)

$L/m^3{}_{\text{baseline}} = 1.861$

$$\text{Quantity}_{\text{baseline fuel}} = 205{,}400 \text{ } m^3 \text{ X } 1.861 \text{ } L/m^3{}_{\text{baseline}}$$

$$\text{Quantity}_{\text{baseline fuel}} = 382{,}249.4 \text{ L}$$

D) Baseline emissions calculations

Baseline emissions are calculated as follows:

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

No additional fuel blending or electricity generation was used in this example so this emissions were excluded simplying. ppstream emissions calculations as follows:

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

Upstream and combustion emissions were calculated using a combined emission factor provided in Appendix E.

$$\text{Emissions}_{\text{Baseline}} = \text{Quantity}_{\text{baseline fuel}} \text{ X } \text{EF}_{\text{combined baseline diesel fuel}}$$

Where:

$\text{Quantity}_{\text{baseline fuel}} = 382{,}249.4$ L

$\text{EF}_{\textit{combined baseline diesel fuel}}$ (CO_2e) = 3674.5 g/L

Thus:

$\text{Emissions}_{\text{Baseline}} = 382{,}249.4$ L X 3674.5 g/L

$\text{Emissions}_{\text{Baseline}} = 1404.6$ tonnes CO_2e (divide by 1,000,000 to get tonnes)

Note: this example assumes that all other potential emission sources are not materially impacted by the switch in fuel. If this assumption is not true, each included source must would need to be quantified separately.

E) Project emissions calculation

Calculate the project condition emissions using direct measurement of fuel and energy use.

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

Fuel combustion emissions are calculated using the measured amount of LNG combusted and Alberta specific emission factors provided in Appendix E:

$$\text{Emissions}_{\text{fuel combustion project}} = \text{Quantity}_{\text{project fuel}} \text{ X } \text{EF}_{\text{project fuel}}$$

In this example the litres of LNG was converted to GJ using a standard conversion of 24 MJ/L for LNG. The emission factor of 52,240 g/GJ of natural gas used was provided in Appendix E.

$\text{Emissions}_{\text{fuel combustion project}} = 13{,}622.7 \text{ GJ X } 52{,}240 \text{ g/GJ } CO_2e$

$\text{Emissions}_{\text{fuel combustion project}} = 711.6 \text{ tonnes } CO_2e$

Project emissions include emissions associated with the liquefaction of natural gas and must be calculated separately. Fossil fuel blending and electricity generation do not occur in this example and are excluded. Project upstream emissions are:

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

Where:

Emissions $_{\text{fuel extraction and processing}}$ = Emissions from extraction, processing and delivery of the natural gas to the Liquefaction facility.

Emissions $_{\text{fuel storage and dispensing}}$ = Emissions to liquefy and dispense the natural gas.

Appendix E provides the upstream emission factor for the natural gas feedstock as 8,201 g/GJ:

$\text{Emissions}_{\text{fuel extraction and processing}} = 13{,}622.7 \text{ GJ X } 8{,}201 \text{ g/GJ } CO_2e$

$\text{Emissions}_{\text{fuel extraction and processing}} = 111.7 \text{ tonnes } CO_2e$

In this example, the project developer is purchasing the LNG from a commercial facility through contract. The supplier reported its energy to liquefy and dispense LNG as 7735 g/GJ liquefied. This information must be based on commercial grade meters and is required for emissions calculations. Emission from liquefaction are:

$\text{Emissions}_{\text{fuel storage and dispensing}} = 13{,}622.7 \text{ GJ X } 7{,}735 \text{ g/GJ } CO_2e$

$\text{Emissions}_{\text{fuel storage and dispensing}} = 105.4 \; tonnes \; CO_2e$

Project upstream emissions are added together as follows:

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

$\text{Emissions}_{\text{fuel extraction and processing}} = 111.7 \text{ tonnes } CO_2e$

$\text{Emissions}_{\text{fuel storage and dispensing}} = 105.4 \text{ tonnes } CO_2e$

$\text{Emissions}_{\text{upstream project}} = 217.1 \text{ tonnes } CO_2e$

The upstream emissions are added to the combustion emissions to get the total project emissions:

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

$$\text{Emissions}_{\text{upstream project}} = 217.1 \text{ tonnes } CO_2e$$

$$\text{Emissions}_{\text{fuel combustion project}} = 711.6 \text{ tonnes } CO_2e$$

$$\text{Emissions}_{\text{Project}} = 928.7 \text{ tonnes } CO_2e$$

F) Emission Reduction Calculation

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

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

$$\text{Emissions}_{\text{Baseline}} = 1404.6 \text{ tonnes } CO_2e$$

$$\text{Emissions}_{\text{Project}} = 928.7 \text{ tonnes } CO_2e$$

Emission Reduction = 475.89 tonnes CO_2e

Appendix D Example of Calculations for Freight Transportation

Example 4. Fuel switching for the transportation of freight

Project scenario: A forest company is seeking to reduce its greenhouse gas emissions by switching from diesel fuel to LNG to power trucks used to haul harvest (tree length logs) from the harvest block to the mill. The trucks have been modified to use LNG (modifications made to the engines and fuel tanksto handle the new fuel). Handling, trailer configuration, load size and routs traveled have not been unchanged.

Baseline scenario (BAU case): Continued use of diesel fuel.

Project plan: Services provided in the project are measured as tonnes hauled per km traveled per unit of fuel used. The services provided during the project were used to estimate baseline fuel volume using a historic baseline. This estimated baseline fuel volume was then used to estimate upstream and combustion emissions for the baseline using approved emission factors provided in Appendix E.

Calculations. The example calculations are broken down into steps explained in parts A through F.

A) Baseline Historic Calculations

Complete conversion of the truck fleet from diesel to LNG will require several years. Therefore, the project developer initiated a monitoring program to determine business as usual hauling practices to collect the required information before the project start date. Baseline data is shown below.

Year	Loads	tonnes	km	L
2011	25,219	1,054,438	1,898,900	1,771,075
2010	21,882	914,899	2,104,147	1,941,216
2009	24,733	1,034,105	2,986,695	2,725,468

The historic baseline was calculated by dividing each of the total distance traveled, tonnes hauled and litres used by the number of trips as shown below.

Year	tonnes	km	L
2011	41.8113	75.296	70.228
2010	41.8106	96.159	88.713
2009	41.8107	120.757	110.196

The litres of diesel per tonne km (L /t·km) is determined as follows:

$$L\ /t\cdot km_{\ Year\ 1} = 70.228/(41.8113 \text{ X } 75.296) = 0.02231$$

$$L\ /t\cdot km_{\ Year\ 2} = 88.713/(41.8106 \text{ X } 96.159) = 0.02207$$

$$L\ /t\cdot km_{\ Year\ 3} = 110.196/(41.8107 \text{ X } 120.757) = 0.02183$$

The three year average is used as the historic baseline for the project:

$$L\ /t\cdot km_{\ baseline} = (L\ /t\cdot km_{\ Year\ 1} + L\ /t\cdot km_{\ Year\ 2} + L\ /t\cdot km_{\ Year\ 3}) / 3 = 0.02207$$

Note: sufficient time was available between the project planning stage and project start to collect the data needed to establish a three year historic baseline required by this protocol. In these cases, the project developer is required to collect census data for the fleet to meet the requirements stated in this protocol. Subsample statistics cannot be used.

B) Project start and monitoring

After one full year of project monitoring, the LNG converted trucks hauled 23,698 loads for a total of 990,855 tonnes over 2,104,147 km. The amount of LNG fuel used for the year was 2,892,562 L that is equivalent to 69,422 GJ of energy using a HHV conversion of 24 MJ/L. The location of each of the blocks included in the project was documented and reported in the offset project report.

Project Summary Data

Year	2012
Loads	23,698
tonnes	990,855
km	2,104,147
L (LNG)	2,892,565
GJ (LNG)	69,422

C) Baseline Fuel Calculation

The baseline fuel is diesel and is measured in litres. The historic baseline calculated in part A of this example is 0.02207 litres of diesel fuel for every tonne·km to determine the amount of fuel that would have been used in the baseline.

$$Quantity_{\ baseline\ fuel} = (\text{tonnes per load X total km}) \text{ X } L\ /t\cdot km_{\ baseline})$$

Where:

tonnes per load = total tonnes hauled by project trucks / total number of loads

total km = total km traveled by project trucks

$L/t\cdot km_{baseline}$ = 0.02207 (from historic benchmark baseline)

$Quantity_{baseline\ fuel}$ = ((990,855 t /23,698) X 2,104,147 km) X 0.02207 L/t·km)

$Quantity_{baseline\ fuel}$ = 1,941,319 L

D) Baseline Emissions Calculations

Baseline emissions are calculated as follows:

$$Emissions_{Baseline} = Emissions_{upstream} + Emissions_{fuel\ combustion}$$

Fuel blending and electricity generation were not included in this example project and have been excluded from the calculations. Thus baseline upstream emissions are simplified as:

$$Emissions_{upstream} = Emissions_{fuel\ extraction\ and\ processing} + Emissions_{fuel\ storage\ and\ dispensing}$$

Upstream and combustion and upstream emissions were calculated using the emission factors provided in Appendix E.

$$Emissions_{Baseline} = Quantity_{baseline\ fuel} \times EF_{combined\ baseline\ diesel\ fuel}$$

Where:

$Quantity_{baseline\ fuel}$ = 1,941,319 L

$EF_{\mathit{combined\ baseline\ diesel\ fuel}}$ (CO_2e) = 3674.5 g/L

Thus:

$Emissions_{Baseline}$ = 1,941,319 L X 3674.5 g/L

$Emissions_{Baseline}$ = 7,133.38 tonnes CO_2e (divide by 1,000,000 to get tonnes)

Note: this example assumes that all other potential emission sources are not materially impacted by the switch in fuel. If this assumption is not true, each included source will need to be quantified separately.

E) Project emissions Calculation

Project emissions are calculated using direct measurements of fuel and energy used.

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

Fuel combustion emissions are calculated using the measured amount of LNG combusted and the emission factors provided in Appendix E:

$$\text{Emissions}_{\text{fuel combustion project}} = \text{Quantity}_{\text{project fuel}} \text{ X EF}_{\text{project fuel}}$$

In this example, the litres of LNG was converted GJ using a standard conversion of 24 MJ/L for LNG. The emission factor was 52,240 g/GJ of natural gas as provided in Appendix E.

$$\text{Emissions}_{\text{fuel combustion project}} = 69{,}422 \text{ GJ X } 52{,}240 \text{ g/GJ } CO_2e$$

$\text{Emissions}_{\text{fuel combustion project}} = 3{,}626.61$ tonnes CO_2e (divide by 1,000,000 to get tonnes)

The project upstream emissions are:

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

Where:

$\textit{Emissions}_{\textit{fuel extraction and processing}}$ = Emissions from extraction, processing and delivery of the natural gas to the Liquefaction facility.

$\text{Emissions}_{\text{fuel storage and dispensing}}$ = Emissions to liquefy and dispense the natural gas.

Appendix E provides the upstream emission factor for the natural gas feedstock as 8,201 g/GJ. Thus:

$$\text{Emissions}_{\text{fuel extraction and processing}} = 69{,}422 \text{ GJ X } 8{,}201 \text{ g/GJ } CO_2e$$

$$\text{Emissions}_{\text{fuel extraction and processing}} = 569.33 \text{ tonnes } CO_2e$$

In this example, the project company is purchasing its LNG from a commercial facility. The supplier reports its energy to liquefy and dispense LNG as 7735 g/GJ liquefied. This information must be generated from commercial grade meters and is required to calculate emissions associated with fuel storage and dispensing:

$$\text{Emissions}_{\text{fuel storage and dispensing}} = 69{,}422 \text{ GJ X } 7{,}735 \text{ g/GJ } CO_2e$$

$$\text{Emissions}_{\text{fuel storage and dispensing}} = 536.98 \text{ tonnes } CO_2e$$

Upstream project emissions are summed:

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

$\text{Emissions}_{\text{fuel extraction and processing}}$ = 569.33 tonnes CO_2e

$\text{Emissions}_{\text{fuel storage and dispensing}}$ = 536.98 tonnes CO_2e

$\text{Emissions}_{\text{upstream project}}$ = 1,106.31 tonnes CO_2e

The upstream emissions are added to the combustion emissions to get total project emissions:

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

$\text{Emissions}_{\text{upstream project}}$ = 1,106.31 tonnes CO_2e

$\text{Emissions}_{\text{fuel combustion project}}$ = 3,626.61 tonnes CO_2e

$\text{Emissions}_{\text{Project}}$ = 4,732.92 tonnes CO_2e

F) Emission Reduction Calculation

Emission reductions are calculated as:

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

$\text{Emissions}_{\text{Baseline}}$ = 7133.38 tonnes CO_2e

$\text{Emissions}_{\text{Project}}$ = 4732.92 tonnes CO_2e

Emission Reduction = 475.89 tonnes CO_2e

Appendix E: Default Emission Factors and Guidance on the Use of Alternative Emission Factors

A number of emission factors (EFs) are required to use of this protocol. These 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.

Most emission factors are derived from the GHGenius model[4]. The GHGenius model was used to develop upstream emissions specific to Alberta for a variety of fuels and feedstocks.

Emission factors provided by the National Inventory Report[5] (NIR) may also be used. The NIR is the Canadian Government's submission to the United Nations Framework Convention on Climate Change (UNFCC). Part two of the report contains stationary and mobile emission factors for most of the fuels anticipated under this protocol.

If the fuel being used is not included in either of the NIR or GHGenius, alternative sources for emission factors may be used if approved by Alberta Environment and Sustainable Resource Development. This approval must be obtained prior to project start and included in the project plan.

A combined upstream emission factor has been developed that includes fuel extraction and processing, fuel storage and dispensing. When additional fuel processing occurs within a project (e.g., onsite natural gas compression for CNG or LNG vehicles), the additional energy required must be quantified separately using appropriate emission factors.

Baseline gasoline and diesel fuel use must include greenhouse gas emission intensity reduction requirements mandated under the Alberta Renewable Fuel Standard.

GHGenius

The GHGenius model was developed for Natural Resources Canada. It was designed to analyze the energy balance and emissions for contaminants associated with the production and use of traditional and alternative transportation fuels.

This model is used to estimate lifecycle emissions of the primary greenhouse gases and the criteria pollutants from combustion sources. The specific gases included in the model are:

- Carbon dioxide (CO_2),
- Methane (CH_4),
- Nitrous oxide (N_2O),
- Chlorofluorocarbons (CFC-12),
- Hydro fluorocarbons (HFC-134a),
- The CO_2-equivalent of all of the contaminants above (CO_2e).
- Carbon monoxide (CO),

[4] Available from http://www.ghgenius.ca
[5] Most recent NIR available from http://www.ec.gc.ca/ges-ghg/

- Nitrogen oxides (NO_x),
- Non-methane organic compounds (NMOCs), weighted by their ozone forming potential,
- Sulphur dioxide (SO_2),
- Total particulate matter.

The model can be used to analyze emissions from conventional and alternative fuelled internal combustion engines or fuel cells for light duty vehicles, for class 3-7 medium-duty trucks, for class 8 heavy-duty trucks, for urban buses; and for light duty battery powered electric vehicles using over 200 different vehicle and fuel combinations.

Historical data or correlations for changes in energy and process parameters with time are stored in the model. This allows the model to predict present and future changes through 2050.

The fuel cycle segments included in the model are:

- Vehicle Operation: Emissions associated with the use of the fuel in the vehicle. Includes all greenhouse gases.
- Fuel Dispensing at the Retail Level: Emissions associated with the transfer of the fuel at a service station from storage into the vehicles. Includes electricity for pumping, fugitive emissions and spills;
- Fuel Storage and Distribution at all Stages: Emissions associated with storage and handling of fuel products at terminals, bulk plants and service stations. Includes storage emissions, electricity for pumping, space heating and lighting;
- Fuel Production (production from raw materials): Direct and indirect emissions associated with conversion of the feedstock into a saleable fuel product. Includes process emissions, combustion emissions for process heat/steam, electricity generation, fugitive emissions and emissions from the life cycle of chemicals used for fuel production cycles;
- Feedstock Transport: Direct and indirect emissions from transport of feedstock, including pumping, compression, leaks, fugitive emissions, and transportation from point of origin to the fuel refining plant. Import/export, transport distances and the modes of transport are considered. Includes energy and emissions associated with the transportation infrastructure construction and maintenance (trucks, trains, ships, pipelines, etc.);
- Feedstock Production and Recovery: Direct and indirect emissions from recovery and processing of the raw feedstock, including fugitive emissions from storage, handling, upstream processing prior to transmission, and mining;
- Feedstock Upgrading: Direct and Indirect emissions from the upgrading of bitumen to synthetic crude oil at a standalone facility, including fugitive emissions;

- Fertilizer Manufacture: Direct and indirect life cycle emissions from fertilizers, and pesticides used for feedstock production, including raw material recovery, transport and manufacturing of chemicals. This is not included if there is no fertilizer associated with the fuel pathway;
- Land use changes and cultivation associated with biomass derived fuels: Emissions associated with the change in the land use in cultivation of crops, including N_2O from application of fertilizer, changes in soil carbon and biomass, methane emissions from soil and energy used for land cultivation;
- Carbon in Fuel from Air: Carbon dioxide emissions credit arising from use of a renewable carbon source that obtains carbon from the air;
- Leaks and flaring of greenhouse gases associated with production of oil and gas: Fugitive hydrocarbon emissions and flaring emissions associated with oil and gas production;
- Emissions displaced by co-products of alternative fuels: Emissions displaced by co-products of various pathways. System expansion is used to determine displacement ratios for co-products from biomass pathways;
- Vehicle assembly and transport: Emissions associated with the manufacture and transport of the vehicle to the point of sale, amortized over the life of the vehicle; and
- Materials used in the vehicles: Emissions from the manufacture of the materials used to manufacture the vehicle, amortized over the life of the vehicle. Includes lube oil production and losses from air conditioning systems.

The main lifecycle stages for crude oil based gasoline or diesel fuel are shown in the following figure E1.

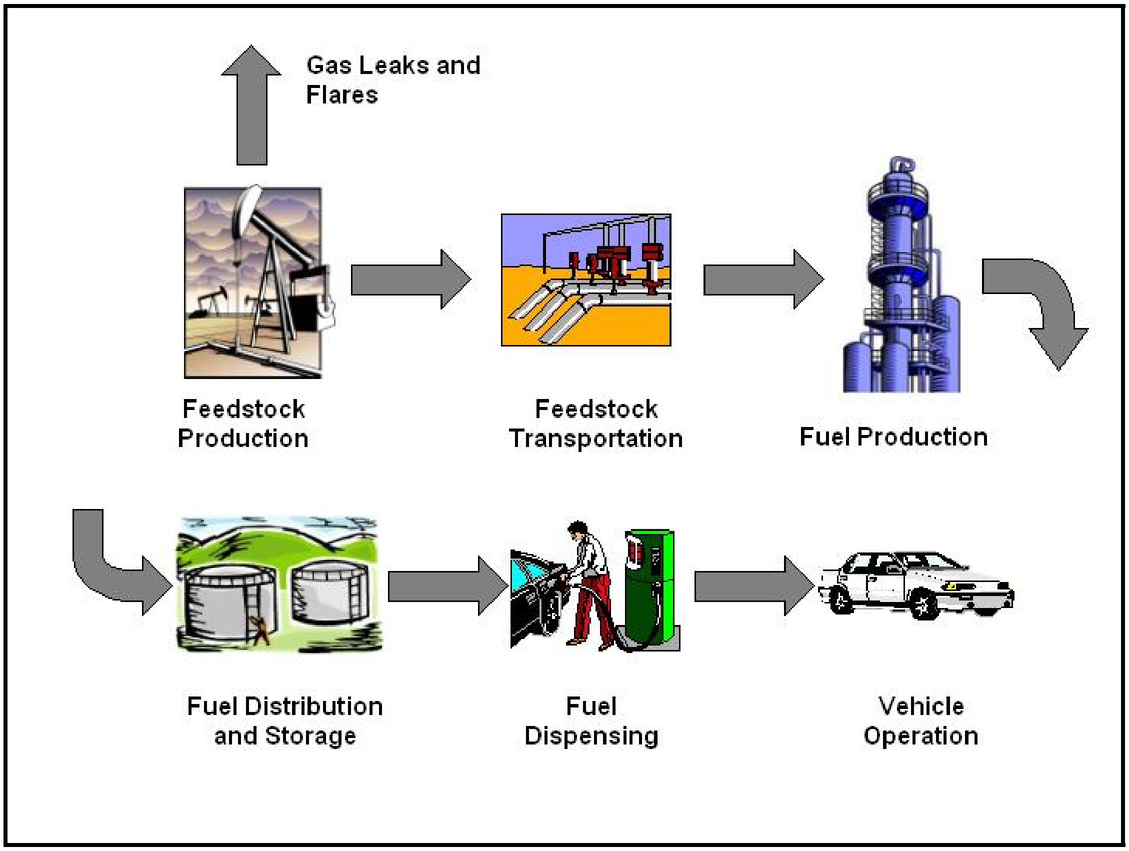


Figure E1. Fuel Lifecycle Stages

The GHGenius model is accessible at www.ghgenius.ca. The current version of the model (GHGenius 4.00c) including documentation on the model, its development and the fuel pathways is available on the website.

GHGenius 4.00c was used to develop the following emission factors.

Alberta Emission Factors

The following five steps are used to extract upstream emission factors for gasoline and diesel fuel in Alberta from GHGenius:

1) Click “I Agree” on the opening sheet, ~cell E123. This opens the model.
2) Click “Alberta” on the Input sheet, ~ cell H2.
3) Set cell B3 to 2012. This sets the model to 2012.
4) Set cell B6 to 0. This selects the 1995 GWPs (CO_2=1, CH_4=21, N_2O=310).
5) Click “Run Program” on the Input sheet, ~ cell A1.

The upstream emission factors expressed in g CO_2e/GJ (HHV) are found on the Upstream Emissions HHV sheet. The values for 100% gasoline and diesel fuel are found in columns D and F, rows 7 to 20. The results are shown in table E1.

Table E1 Gasoline and Diesel Fuel Emission Factors

Fuel	Gasoline	Diesel Fuel
Feedstock	Crude Oil	Crude Oil
	g CO_2e/GJ (HHV)	
Fuel dispensing	459	470
Fuel distribution and storage	655	670
Fuel production	9,914	9,415
Feedstock transmission	374	383
Feedstock recovery	5,882	6,011
Feedstock Upgrading	5,628	5,752
Land-use changes, cultivation	246	246
Fertilizer manufacture	0	0
Gas leaks and flares	2,590	2,586
CO_2, H_2S removed from NG	0	0
Emissions displaced	-162	-162
Total	**25,587**	**25,372**

These emissions are for the crude oil well drilling, crude oil, production, refining, distribution, and dispensing at the retail station and do not include emissions associated with the combustion of fuel in vehicles.

Emissions including combustion in vehicles and upstream production emissions are provided in Table E2 and E3 below The exhaust emissions are found on the Exhaust Emissions sheet. The gasoline value is from cell C96 and the diesel fuel is from cell B142.

These emissions are also available on a g/litre basis in sheet Lifecycle Emissions 2. Gasoline in cells C10 (exhaust) and the sum of C13 to C23 for upstream. Diesel in cells B 65 for exhaust and the sum of B68 to 78 for upstream. Values are provided below.

Table E2: Lifecycle Emissions - Energy Basis

Fuel	Gasoline	Diesel Fuel
Feedstock	Crude Oil	Crude Oil
	g CO_2e/GJ (HHV)	
Upstream Emissions	25,587	25,372
Combustion Emissions	63,694	70,294
Total Lifecycle Emissions	89,281	95,666

Table E3: Lifecycle Emissions - Volumetric Basis

Fuel	Gasoline	Diesel Fuel
Feedstock	Crude Oil	Crude Oil
	g CO_2e/litre (HHV)	
Upstream Emissions	887.5	980.7
Combustion Emissions	2,209.3	2,717.1
Total Lifecycle Emissions (Alberta Renewable Fuel Standard)	3,096.9 (3,021.3)	3,697.8 (3674.5)

Renewable Fuels

The Alberta Renewable Fuel Standard (RFS) mandates renewable fuel blend requirements for gasoline and diesel fuel sold in Alberta. The RFS requires an average of two per cent renewable diesel in diesel fuel and five per cent renewable alcohol in gasoline sold in Alberta. Renewable fuels used to meet the RFS must demonstrate at least 25 per cent fewer greenhouse gas emissions than the equivalent petroleum fuel determined on an energy basis.

The renewable alcohol is measured on a basis of ethanol equivalent. The ethanol energy content in GHGenius is 67.98 per cent of gasoline (23.579 MJ/litre vs. 34.686 MJ/litre). Five percent ethanol (E5) represents 3.4 per cent of the energy in the fuel. The production and combustion emissions associated with this five per cent ethanol must be 25 per cent less than that of gasoline. The emissions for the E5 blend with a 25 per cent reduction in greenhouse gas emissions are 88,522 g CO_2e/GJ (0.966*89,281+0.034*89,281*0.75). The energy content of the E5 blend is 34.131 MJ/litre. **The emissions factor for gasoline is 3,021.3 g CO_2e/litre (HHV)**.

The renewable content in diesel can be met using biodiesel or renewable diesel. It is assumed that most will be met with biodiesel. The energy content of biodiesel and diesel are 35.4 and 38.653 MJ/litre respectively. The two per cent biodiesel (B2) content represents 1.85 per cent of the energy content of the blend. The emissions from the B2 blend with a 25 per cent reduction in greenhouse gas emissions is 95,224 g CO_2e/GJ (0.9815*95,666+0.0185*95,666*0.75). The energy content of the B2 blend is 38.588 MJ/litre. **The emissions factor for diesel is 3,674.5 g CO_2e/litre (HHV).**

Other Fossil Fuels

Propane

Propane is used as a vehicle fuel in dedicated vehicles and in dual fuel vehicles. It is a usually used as a gaseous fuel, but under moderate pressure becomes liquid. Propane used as a transportation fuel use is usually dispensed as a liquid measured in litres.

Propane is produced as a co-product at natural gas plants and petroleum refineries. In GHGenius, it is assumed to be 86 per cent from gas plants and 14 per cent from refineries.

The upstream emissions are found in column N, rows 7 to 20 on the Upstream Emissions sheet. The GHGenius results for Alberta are shown in the table E4 below. Lifecycle emissions for propane are provided in Table E5.

Table E4: Propane Upstream Emissions

Fuel	Propane (LPG)
Feedstock	86% Gas Plants/14% Refineries
	g CO_2e/GJ (HHV)
Fuel dispensing	471
Fuel distribution and storage	519
Fuel production	2,725
Feedstock transmission	54
Feedstock recovery	2,822
Feedstock Upgrading	0
Land-use changes, cultivation	36
Fertilizer manufacture	0
Gas leaks and flares	883
CO_2, H_2S removed from NG	752
Emissions displaced	-23
Total	8,238

Table E5: Lifecycle Emissions - Propane

Fuel	Propane	
Feedstock	86% Gas Plants/14% Refineries	
	g CO_2e/GJ (HHV)	g CO_2e/litre (HHV)
Upstream Emissions	8,238	209.8
Combustion Emissions	59,400	1,512.7
Total Lifecycle Emissions	67,638	1,722.5

The exhaust emissions for propane are found in cell O96 (59,400 g CO_2e/GJ) on the Exhaust Emissions sheet. The lifecycle emissions are shown above. The emissions can also be found on a g/litre basis on sheet Lifecycle Emissions 2. Propane is in cells K10 (exhaust) and the sum of K13 to K23 for upstream.

Natural Gas

Natural gas can be used as a transportation fuel. It is as a gaseous fuel that is stored and dispensed under pressure. It is measured in kilograms. GHGenius includes the energy and emissions associated with the dispensing of the fuel in dispensing emissions. These emissions are dependent on the gas inlet pressure and the compressed pressure, which must be determined separately by the project developer. These emissions are not included in the upstream emissions provided here.

The upstream emissions for natural gas are found in column Q, rows 7 to 20 on the Upstream Emissions sheet and shown in Table E6 below. The exhaust emissions for natural gas are found in cell G96 (52,240 g CO_2e/GJ) on the Exhaust Emissions sheet. The lifecycle emissions are shown in Table E7 below. The emissions can also be found on a g/kg basis on sheet Lifecycle Emissions 2. Natural gas is in cells G65 (exhaust) and the sum of G68 to G78 for upstream.

Table E6: Natural Gas Upstream Emissions

Fuel	**Natural Gas**
Feedstock	Natural Gas
	g CO_2e/GJ (HHV)
Fuel dispensing	0
Fuel distribution and storage	1,354
Fuel production	1,485
Feedstock transmission	0
Feedstock recovery	2,210
Feedstock Upgrading	0
Land-use changes, cultivation	0
Fertilizer manufacture	0
Gas leaks and flares	2,269
CO_2, H_2S removed from NG	882
Emissions displaced	0
Total	8,201

Table E7 Lifecycle Emissions – Natural Gas[6]

Fuel	**Natural Gas**	
Feedstock	Natural Gas	
	g CO_2e/GJ (HHV)	g CO_2e/kg (HHV)
Upstream Emissions	8,201	433.6
Combustion Emissions	52,240	2,760.6
Total Lifecycle Emissions	60,441	3,194.2

Calculating a Single Combustion Emission Factor for Blended Fuel

Switching to a lower greenhouse gas emission intensity fossil fuel blend is permissible under this protocol. Both 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. **Alberta prefers the that project developers use separate emission factors for each fuel constituent as this simplifies the calculations and reduce the chance of error.**

[6] Excluding Compression Emissions

A single emission factor for mobile sources may apply to dual fuel engines that consume small quantities of diesel in combination with natural gas to overcome issues with compression ignition, 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. These multi fuel engines must track each and quantify each fuel separately.

The emission factors required for use of this protocol must be from accepted sources (e.g., National Inventory Reports, Environment Canada, GHGenius), or be approved by AESRD. Guidance on selection and use of emission factors for the Alberta Offset System is provided in the *Technical Guidance for Offset Protocol Developers.*

If the following assumptions are met, a single emission factor for fossil fuel blends is calculated according to the methodology provided below:

1) Each constituent of the blended fuel has an emission factor from an acceptable source; and
2) The combustion efficiency of the blended fuel is similar (within 5 per cent) or better than each fuel combusted individually.

Volume-based emission factor calculation:

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

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

This calculation will need to be done separately for each greenhouse gas species (CO_2, CH_4 and N_2O) as these gasses need to be calculated separately, and summed on a CO_2e basis.

Example

A project fuel contains a blend of 80 per cent standard diesel and 20 per cent natural gas reported using consistent units. The accepted emission factors for one unit (g/L) of diesel are 2663 CO_2, 0.12 CH_4, and 0.082 for N_2O. The accepted emission factors for natural gas are (g/L) are 1212 CO_2, 0.5950 CH_4, and 0.1170 for N_2O.

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

Substituting the appropriate values for each greenhouse gas into the equation for both fuel constituents yields:

$EF\ CO_2 = (0.8 \text{ X } 2663) + (0.2 \text{ X } 1212)$

$= 2372.8$ g/L

$EF\ CH_4 = (0.8 \text{ X } 0.12) + (0.2 \text{ X } 0.5950)$

$= 0.215$ g/L

$EF\ N_2O = (0.8 \text{ X } 0.082) + (0.2 \text{ X } 0.1170)$

$= 0.08902$ g/L

Emissions for CH_4 and N_2O are multiplied by the appropriate global warming potentials to get emissions expressed as units of CO_2e.

$EF\ CH_4 = 4.515$ g/L CO_2e

$EF\ N_2O = 27.599$ g/L CO_2e