Draft Methodological Tool

"Upstream leakage emissions associated with fossil fuel use"

(Version 01.0.0)

I. DEFINITIONS, SCOPE, APPLICABILITY AND PARAMETERS

Definitions

For the purpose of this tool, the following definitions apply:

Upstream emissions stage. The segmentation of upstream emissions into stages based on distinct activities occurring within a stage. Upstream emissions stages are interdependent and lead from one to the next, typically consisting of production, processing, transmission, storage and distribution. Upstream emissions stages may be broadly generalized for types of fossil fuel. However, only some of the upstream emission stages may apply to a particular fossil fuel because of location and application-specific circumstances. For example, a particular natural gas may go directly from the production stage to the distribution stage, without going through any processing, transmission or storage upstream emissions stages.

Upstream emissions. The greenhouse gas (GHG) emissions associated with the production, processing, transmission, storage and distribution of a fossil fuel, beginning with the extraction of raw materials from the fossil fuel origin and ending with the delivery of the fossil fuel to the site of use.

Fossil fuel origin. This refers to the location and type of reservoir(s) or mine(s) from which the fossil fuel originates. The type of reservoir differentiates key characteristics which influence upstream emissions. For natural gas based fossil fuels the types of reservoirs include sweet, sour, coal-bed, shale or associated gas. For coal-based fuels the types of mines include underground or surface.

Scope and applicability

This tool provides a procedure to calculate leakage upstream emissions associated with the use of fossil fuels. The tool is applicable to fossil fuel use in either or both the baseline scenario and project activity as well as fossil fuel consumption for leakage emission sources.

Upstream emissions associated with fossil fuel use are:

(a) Fugitive emissions of CH_4 and CO_2, including venting, flaring and physical leakage from equipment;

(b) CO_2 emissions from combustion of fossil fuels; and

(c) CO_2 emissions associated with consumption of electricity.

Other GHG emissions sources, such as those associated with the construction of equipment are relatively small and therefore not considered.

The tool has two options to determine these emissions: Option (A) provides simple default emission factors for different types of fossil fuels, and Option (B) calculates emission factors based on emissions for each upstream emissions stage. Option (B) requires identifying the relevant upstream emissions stages and the corresponding emission factor for each stage, which may be a default value or calculated, such as according to the 2006 IPCC Tier 2 or 3 methodology.

This tool is applicable to the following types of fossil fuels, which can be categorized to be either based on natural gas, oil or coal:

Natural gas:

(a) Natural gas;

(b) Natural gas liquids (mixtures of primarily pentanes and heavier hydrocarbon);

(c) Propane, butane, and other types of liquefied petroleum gas (LPG);

(d) Liquefied natural gas (LNG);

(e) Compressed natural gas (CNG);

Oil:

(f) Light fuel oil (diesel);

(g) Heavy fuel oil (bunker or marine type);

(h) Gasoline;

(i) Kerosene (household and aviation);

(j) Propane, butane, and other types of liquefied petroleum gas (LPG);

Coal:

(k) Coal; and

(l) Lignite.

Methodologies which refer to this tool should state:

(a) The fossil fuel type(s), as listed above, for which upstream emissions should be determined. For the situation that the fossil fuel is defined at the project level, instead of in the methodology, and does not exactly match a type listed above, then the closest approximation shall be selected in terms of the fuel characteristics (e.g natural gas, oil or coal based fuel) and fossil fuel lifecycle stages (see Table 3);

(b) Procedures to determine the amount of each fossil fuel type(s) used in the baseline or project situation on a net calorific value (NCV); and

(c) If leakage upstream emissions values of less than 0 are acceptable, such as for project activities in which a fossil fuel in the baseline situation is displaced with a renewable fuel in the project situation. Otherwise, if negative values are calculated using this tool, then they are assumed to equal 0.

This tool also refers to the latest approved version of the following tools:

- "Tool to determine project, leakage or baseline emissions from electricity consumption"; and
- "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion".

For more information regarding the proposed new methodologies and the tools, as well as their consideration by the Executive Board, please refer to <http://cdm.unfccc.int/goto/MPappmeth>.

The applicability conditions of these tools also apply.

Parameters

This tool provides procedures to determine the following parameter:

Parameter	SI Unit	Description
$LE_{US,y}$	t CO_2e / yr	Leakage upstream emissions in year *y*

The following data, for which provisions are not given in the tool, are required by this tool. The underlying methodology shall provide the corresponding procedures.

Parameter	SI Unit	Description
$FC_{PJ,x,y}$	TJ / yr	Quantity of fossil fuel type *x* used in the project situation in year *y* (on a NCV basis)
$FC_{BL,x,y}$	TJ / yr	Quantity of fossil fuel type *x* used in the baseline situation in year *y* (on a NCV basis)

II. METHODOLOGY PROCEDURE

Leakage upstream emissions shall be determined using one of the following two options:

- Option (A): Simple approach based on default emission factors; or
- Option (B): Refined approach based on the upstream emissions stages of the fossil fuel.

In the case that part of the upstream emissions occur within the project boundary of the CDM project activity (e.g. the project activity is implemented in a refinery), then project participants shall apply option (B). Otherwise, project participants may choose between option (A) and option (B). The project participants should document in the CDM-PDD and monitoring reports which approach is applied. The approach may be changed during the crediting period, however a combination of options (A) and (B) is not allowed in the same monitoring period.

Option (A): Simple approach based on default emission factors

Leakage upstream emissions are calculated as follows:

$$LE_{US,y} = \sum_{x} EF_{US,x,default} \cdot \left(FC_{PJ,x,y} - FC_{BL,x,y}\right) \quad \textbf{(1)}$$

If $LE_{US,y}$ is calculated as a value of less than 0, then a value of 0 shall be used instead, unless the methodology referencing this tool specifies that negative values for $LE_{US,y}$ are permitted.

Where:

$LE_{US,y}$	=	Leakage upstream emissions in year *y* (t CO_2e / yr)
$FC_{PJ,x,y}$	=	Quantity of fossil fuel type *x* used in the project situation in year *y* (TJ / yr)
$FC_{BL,x,y}$	=	Quantity of fossil fuel type *x* used in the baseline situation in year *y* (TJ / yr)
$EF_{US,x,default}$	=	Default emission factor for upstream emissions associated with consumption of fossil fuel type *x* (t CO_2e / TJ)
x	=	Fossil fuel types used in the project and/or baseline situation and for which upstream emissions should be determined

Select $EF_{US,x,default}$ from ***[Please note: The default emission factors proposed in the table below will undergo a peer review and therefore there is potential that they may change. Comments on the procedure for estimating these defaults (see footnote 1) and the values are welcome]***

Table 1 for the corresponding fossil fuel type *x*. In this table, a simple default emission factors is provided for each fossil fuel type, not distinguishing factors for different fossil fuel origin except for coal based fuels. For this fuel type, there are default emission factors provided if it is known that the coal based fuel is wholly sourced from an underground mine or mine(s) located in the host country of the project activity. Default factors are also provided for the situation that this information is not available.

These default values have been determined using the approach for Option B.[1]

[Please note: The default emission factors proposed in the table below will undergo a peer review and therefore there is potential that they may change. Comments on the procedure for estimating these defaults (see footnote 1) and the values are welcome]

Table 1: Default emission factors for upstream emissions for different types of fossil fuels ($EF_{US,x,default}$)

Fossil fuel type *x*		Default emission factor (t CO_2e / TJ)
Natural Gas (NG)		27.6
Natural Gas Liquids (NGL)		5.4
Liquefied Natural Gas (LNG)		47.7
Compressed Natural Gas (CNG)		29.4
Light Fuel Oil (Diesel)		23.8
Heavy Fuel Oil (Bunker or Marine Type)		14.2
Gasoline		19.4
Kerosene (household and aviation)		12.5
LPG (including butane and propane)		***[To be determined]***
Coal (unknown mine location(s) or coal/lignite not 100% sourced from within host country)	Lignite	2.9
	Surface mine, or any other situation	2.8
	Underground (100% source)	10.4
Coal (coal/lignite 100% sourced from within host county)	Lignite	6.0
	Surface mine, or any other situation	5.8
	Underground (100% source)	21.4

[1] The approach to calculate the default values is to sum together the emission factors for each of the upstream emission stages for fossil fuel type *x*, as listed in Table 3. If there is a range given in Table 3 for an emission factor, then the average value is used. Further, for oil-based fuels, the emission factor for Exploration and Production, Upgrading and/or Refining and Transportation stages is multiplied by a discount factor of 0.76 to account for the situation that a proportion of globally traded fuel is sourced from Annex 1 countries. The emission factors for coal based fuels are multiplied by 0.48 for the same reason.

Option (B) Detailed approach based on upstream emissions stages

This approach estimates upstream emissions by summing the emissions occurring in each upstream emissions stage relevant to the fossil fuel used in the project or baseline situation. This requires identifying:

- Fossil fuel type(s) and origin;
- Upstream emissions stages that are applicable to each fossil fuel type and origin; and
- Emission factors corresponding to each applicable upstream emissions stage.

Upstream leakage emissions are then calculated as follows:

$$LE_{US,y} = \sum_{x}\sum_{i}\sum_{j} EF_{i,j,x,y} \cdot \left(FC_{PJ,x,j,y} - FC_{BL,x,j,y}\right) \qquad \textbf{(2)}$$

Where:

$LE_{US,y}$	=	Leakage upstream emissions in year y (t CO_2e / yr)
$EF_{i,j,x,y}$	=	Emission factor for upstream emissions stage i associated with consumption of fossil fuel type x from fossil fuel origin j applicable to year y (t CO_2e / TJ)
$FC_{PJ,x,j,y}$	=	Quantity of fossil fuel type x from fossil fuel origin j used in the project situation in year y (TJ / yr)
$FC_{BL,x,j,y}$	=	Quantity of fossil fuel type x from fossil fuel origin j used in the baseline situation in year y (TJ / yr)
x	=	Fossil fuel types for which upstream emissions are determined
i	=	Upstream emissions stage
j	=	Fossil fuel origin(s) in year y

Step 1: Identifying the fossil fuel origin j

The fossil fuel origin is needed to determine the emission factor for an upstream emissions stage using Option (B) and may also be useful for identifying the applicable upstream emissions stages for each fossil fuel type.

For oil based fossil fuel types, the fossil fuel origin is *global*[2]. For coal based fossil fuel types, the fossil fuel origin is also *global,* unless the fossil fuel origin is clearly identified as a mine located within the host country. For all other situations and fossil fuel types the fossil fuel origin must be determined. Where it is not possible to identify the fossil fuel origin, then it should be determined based on reasonable and conservative assumptions for the region or jurisdiction. For instance, if a fossil fuel type used in the project activity could potentially be sourced from one of several fossil fuel origins, then it can be assumed to have only one fossil fuel origin as long as this is justified to be conservative. The basis for determining the fossil fuel origin, and if relevant the justification of why any assumptions are conservative, shall be documented in the CDM-PDD and monitoring reports.

Each year it shall be checked if the fossil fuel origin(s) has changed, and if it has changed, then the Option (B) procedure must be updated.

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[2] A global fossil fuel origin represents the situation that it is not possible to confirm the exact source of the fossil fuel that would be replaced or used as a result of a CDM project activity, given that oil and its products are globally traded commodity. In which exact location oil production is increased or decreased as a result of a CDM project activity may depend on many factors, such as the marginal production costs, the location of the host country, the current prices for raw oil, or geopolitical factors. For example, a project activity located in an oil producing country may not necessarily impact the oil production in that country but could instead increase or decrease the export or import of oil.

As a check, the sum of the fossil fuel consumption of each fossil fuel origin for fossil fuel type x shall equal the quantity of fossil fuel x consumed in the baseline and project situations, as follows:

$$FC_{PJ,x,y} = \sum_j FC_{PJ,x,j,y} \tag{3}$$

and

$$FC_{BL,x,y} = \sum_j FC_{BL,x,j,y} \tag{4}$$

Where:

$FC_{PJ,x,j,y}$	=	Quantity of fossil fuel type *x* from fossil fuel origin *j* used in the project situation in year *y* (TJ / yr)
$FC_{BL,x,j,y}$	=	Quantity of fossil fuel type *x* from fossil fuel origin *j* used in the baseline situation in year *y* (TJ / yr)
$FC_{PJ,x,y}$	=	Quantity of fossil fuel type *x* used in the project situation in year *y* (TJ / yr)
$FC_{BL,x,y}$	=	Quantity of fossil fuel type *x* used in the baseline situation in year *y* (TJ / yr)
x	=	Fossil fuel types for which upstream emissions are determined
j	=	Fossil fuel origin(s) in year *y*

Step 2: Identifying upstream emissions stages

The upstream emissions stages *i* that are potentially applicable for each fossil fuel type and origin are listed in Table 3. Those stages that shall always be assumed to apply for a given fossil fuel type are identified as a mandatory upstream emissions stage. Otherwise, the stage may or may not apply depending on the project specific circumstance and fossil fuel origin. If there is uncertainty as to whether a particular stage is applicable, then for fuel consumption that is higher in the project situation than the baseline, then it shall be assumed to apply, and otherwise it shall be assumed to not apply.

Step 3: Identifying the emission factor corresponding to each upstream emissions stage ($EF_{i,j,x,y}$)

For fossil fuel types with a *global* fossil fuel origin or an origin identified to be located in an Annex 1 country, then the emission factor corresponding to specified upstream emissions stages *i* are calculated as follows:

- For oil-based fuels, because their fossil fuel origin j is global, the emission factors for the Exploration and Production, Upgrading and/or Refining and Transportation stages shall be selected from the list of default emission factors in Table 3 (selecting an average, where a range in values is given), and multiplied by 0.763.
- For coal based fuels with a fossil fuel origin j that is global, the emission factor for each upstream emission stage shall be selected from the list of default emission factors in Table 3 and multiplied by 0.483.
- For a natural gas based fuel with a fossil fuel origin *j* located in an Annex 1 country, and the case that fuel consumption of type *x* from this origin *j* is higher in the baseline situation than in the project situation, then the emission factor is 0 for the Exploration and Production, and Processing stages.

[3] These adjustment factors for fossil fuels with a *global* fossil fuel origin are to account for the situation that a proportion of globally traded oil and coal is exported by Annex 1 countries and emission reductions can not be claimed in these countries. The basis of this factors is 2003-08 coal export data and 2005-09 oil export data from the U.S Energy Information Administration, *International Energy Statistics.*

For all other situations project participants may select for each upstream emissions stage *i*, from either Option (1) or Option (2) to determine the emission factor corresponding to each upstream emissions stage (e.g. different options may be selected for each upstream emission stages of fossil fuel type *x* from fossil fuel origin *j*):

- Option (1): Select a default emission factor from Table 3.
- Option (2): Determine a refined emission factor that is specific to the project activity.

The data needed to support the development of refined emission factors may be difficult to obtain and the refined approach will typically only be practical for either fossil fuel origins that can be identified as a particular reservoir or mine or for upstream emissions stages that have few activities and the emission sources are easy to identify.

Option (1): Default emission factors

Select $EF_{i,j,x,}$ from the list of default emission factors for upstream emissions stages in Table 3. Where the default emission factor is given as a range of values, follow the instructions given in the table notes on how to choose the appropriate value within the range.

Option (2): Refined emission factors

Developing a refined $EF_{i,j,x}$ requires determining the GHG emissions associated with the following emission sources in the upstream emissions stage:

- For oil and natural gas based fossil fuels:
  - Fossil fuel consumption ($E_{Fuel,i,j,x,t}$);
  - Purchased electricity consumption ($E_{Electricity,i,j,x,t}$);
  - Flaring ($E_{Flaring,i,j,x,t}$);
  - Venting($E_{Venting,i,j,x,t}$);
  - Leaks from equipment ($E_{Leaks,i,j,x,t}$);
  - Storage losses ($E_{Storage\ Losses,i,j,x,t}$);
- For coal based fossil fuels:
  - Fugitive methane emissions (EFugitive,i,j,x,t);
  - Fossil fuel consumption (EFuel,i,j,x,t); and
  - Purchased electricity consumption ($E_{Electricity,i,j,x,t}$).

The calculation of the emission factor(s) shall be updated at the renewal of the crediting period or if the fossil fuel origin *j* changes.

To calculate the emission factor, the total GHG emissions from the upstream emissions stage during a representative time period *t* are divided by the amount of the fossil fuel output by the upstream emissions stage during the same time period *t* ($FP_{i,j,x,t}$). Sufficient data should be used to ensure balanced weighting of any variations in emission intensities, such as due to seasonal variations in production and process performance. The time period *t* should therefore be at least one year.

The emission factor is calculated using Equation 5 for oil and natural gas based fossil fuels and Equation 6 for coal. A simplified approach is given in Equation 7 for the situation that the key activities of an upstream emissions stage comprise only transportation.

Refined emission factor for an upstream emissions stage associated with oil or natural gas based fuels are calculated as follows:

$$EF_{i,j,x,y} = \frac{1}{FP_{i,j,x,t}} \cdot \left(E_{Fuel,i,j,x,t} + ER_{Flaring,i,j,x,t} + ER_{Venting,i,j,x,t} + ER_{Leaks,i,j,x,t} + ER_{StorageLosses,i,j,x,t} + ER_{Electricity,i,j,x,t} \right) \quad \textbf{(5)}$$

Where:

$EF_{i,j,x,y}$	=	Emission factor for upstream emissions associated with upstream emissions stage *i* of fossil fuel *x* from fossil fuel origin *j* applicable for year *y* (t CO_2e / TJ)
$FP_{i,j,x,t}$	=	Fuel output from upstream emissions stage *i* of fossil fuel type *x* from fossil fuel origin *j* in the time period *t* (TJ)
$E_{Fuel,i,j,x,t}$	=	Emissions from consumption within upstream emissions stage *i* of fossil fuel type *x* from fossil fuel origin *j* in the time period *t* (t CO_2e)
$E_{Flaring,i,j,x,t}$	=	Emissions from flaring within upstream emissions stage *i* of fossil fuel type *x* from fossil fuel origin *j* in the time period *t* (t CO_2e)
$E_{Venting,i,j,x,t}$	=	Emissions from venting within upstream emissions stage *i* of fossil fuel type *x* from fossil fuel origin *j* in the time period *t* (t CO_2e).
$E_{Leaks,i,j,x,t}$	=	Emissions from fugitive equipment leaks within upstream emissions stage *i* of fossil fuel type *x* from fossil fuel origin *j* in the time period *t* (t CO_2e)
$E_{StorageLosses,i,j,x,t}$	=	Emissions from storage losses within upstream emissions stage *i* of fuel type *x* from fossil fuel origin *j* in the time period *t* (t CO_2e)
$E_{Electricity,i,j,x,t}$	=	Emissions associated with electricity consumption within upstream emissions stage *i* of fuel type *x* from fossil fuel origin *j* in the time period *t* (t CO_2e)
x	=	Fossil fuel types for which upstream emissions are determined
i	=	Upstream emissions stage associated with oil and natural gas based fuels
j	=	Fossil fuel origin(s) in year *y*
t	=	Time period of at least one year

Refined emission factor for an upstream emissions stage associated with coal based fuels are calculated as follows:

$$EF_{i,j,x,y} = \frac{1}{FP_{i,j,x,t}} \cdot \left(E_{Fuel,i,j,x,t} + E_{Fugitives,i,j,x,t} + E_{Electricity,i,j,x,t} \right) \quad \textbf{(6)}$$

Where:

$EF_{i,j,x,y}$	=	Emission factor for upstream emissions associated with upstream emissions stage *i* of fossil fuel *x* from fossil fuel origin *j* applicable for year *y* (t CO_2e / TJ)
$FP_{i,j,x,t}$	=	Fuel output from upstream emissions stage *i* of fossil fuel type *x* from fossil fuel origin *j* in the time period *t* (TJ)
$E_{Fuel,i,j,x,t}$	=	Emissions from consumption within upstream emissions stage *i* of fossil fuel type *x* from fossil fuel origin *j* in the time period *t* (t CO_2e)
$E_{Fugitives,i,j,x,t}$	=	GHG emission rate from fugitive sources within upstream emissions stage *i* of fuel type *x* from fossil fuel origin *j* in the time period *t* (t CO_2e)
$E_{Electricity,i,j,x,t}$	=	Emissions associated with electricity consumption within upstream emissions stage *i* of fuel type *x* from fossil fuel origin *j* in the time period *t* (t CO_2e)
x	=	Fossil fuel types for which upstream emissions are determined
i	=	Upstream emissions stage associated with coal based fuels
j	=	Fossil fuel origin(s) in year *y*
t	=	Time period of at least one year

A simplified equation is provided below to determine the refined emission factor for upstream emissions stages that only comprise transportation activities. As well as updating the emission factor at the renewal of the crediting period or if the fossil fuel origin changes, the emission factor shall also be recalculated if the mode of transportation *r* changes, or for the case that there is more than one transport mode *r* and the relevant proportion of fuel transported by these modes changes.

$$EF_{i,j,x,y} = \frac{\sum_{r}\left(EF_{FT,r,default} \cdot FP_{i,j,x,r,t} \cdot DT_{i,j,x,r,t}\right)}{NCV_{x} \cdot FP_{i,j,x,t}} \qquad \textbf{(7)}$$

Where:

$EF_{i,j,x,y}$	=	Emission factor for upstream emissions associated with upstream emissions stage *i* of fossil fuel *x* from fossil fuel origin *j* applicable for year *y* (t CO_2e / TJ)
$EF_{FT,r,\ default}$	=	Emission factor for the emissions associated with energy consumed in transporting fossil fuel by mode *r* (t CO_2e / t km)
$FP_{i,j,x,r,t}$	=	Fossil fuel type *x* from fossil fuel origin *j* transported in upstream emissions stage *i* by mode *r* in the time period *t* (TJ)
$DT_{i,j,x,r,t}$	=	Distance that fossil fuel *x* from fuel origin *j* was transported by mode *r* in upstream emissions stage *i* in the time period *t* (km)
NCV_x	=	Net calorific value of the fossil fuel *x* (TJ / t)
$FP_{i,j,x,t}$	=	Fuel output from upstream emissions stage *i* of fossil fuel type *x* from fossil fuel origin *j* in the time period *t* (TJ)
x	=	Fossil fuel types for which upstream emissions are determined
i	=	Upstream emissions stage that comprises only transport activity
j	=	Fossil fuel origin(s) in year *y*
r	=	Transport modes in year *y*
t	=	Time period of at least one year

Select $EF_{FT,r,default}$ from **Table 2** for the corresponding transport mode *r*. In the case that a fuel type *x* is used both in the project activity and in the baseline, then the default emission factor for the baseline shall be applied where the fuel consumption under the baseline exceeds the fuel consumption under the project activity. Otherwise, the default emission factor for the project situation shall be applied.

Table 2: Default emission factors for different modes of petroleum transportation ($EF_{FT,r,default}$)

Transport Mode	Default emission factor for baseline situation (t CO2/ t km)	Default emission factor for project situation (t CO2/ t km)
Road transport [1]	76×10^{-6}	129×10^{-6}
Rail transport	22×10^{-6}	22×10^{-6}
Barge transport	31×10^{-6} or 0 if trip consists of international shipping*	31×10^{-6}
Short sea	16×10^{-6} or 0 if trip consists of international shipping*	16×10^{-6}
Deep-sea tanker	5×10^{-6} or 0 if trip consists of international shipping*	5×10^{-6}
Intermodal road/rail	26×10^{-6}	26×10^{-6}
Intermodal road/barge	34×10^{-6}	34×10^{-6}
Intermodal road/short sea	21×10^{-6}	21×10^{-6}

Pipelines (Crude Oil and Refined Product Transport)[2]	2.8×10^{-6}	5.9×10^{-6}
Pipelines (Natural Gas Transmission)[3]	5×10^{-6}	65×10^{-6}
Pipeline (Natural Gas Distribution)[4]	0.4×10^{-6}	0.6×10^{-6}

Source: *CEFIC. 2011. Guidelines for Measuring and Managing CO2 Emissions from Freight Transport Operations. Issue 1/March 2011. pp. 19.* , and:

1. Emission factor for the baseline situation has been obtained from empirical data from European vehicles (Les émissions de CO2 par les poids lourds français entre 1996 et 2006 ont augmenté moins vite que les volumes transportés.. Commissariat Général au Développement Durable. # 25, 2009). The emission factor for the project situation has been derived based on custom design transient speed-time-gradient drive cycle (adapted from the international FIGE cycle), vehicle dimensional data, mathematical analysis of loading scenarios, and dynamic modeling based on engine power profiles, which, in turn, are a function of gross vehicle mass (GVM), load factor, speed/acceleration profiles and road gradient.
2. Based on detailed greenhouse gas emissions data and system data available for one major pipeline transporter of crude oil and refined petroleum products for different pipeline networks that operated in North America.
3. Based on detailed greenhouse gas emissions data and system data available for two natural gas transmission pipeline systems in North America.
4. Based on detailed greenhouse gas emissions data and system data available for two natural gas distribution pipeline systems in North America.

* Baseline emissions associated with international shipping are ignored in this tool, because emission reduction commitments set under the Kyoto Protocol do not include emissions by international shipping.

Determining the emissions from emission sources

Emissions associated with electricity consumption ($E_{Electricity,i,j,x,y}$) shall be determined using the "Tool to determine project, leakage or baseline emissions from electricity consumption". Emissions associated with fossil fuel consumption ($E_{Fuel,i,j,x,y}$) shall be determined using the "Tool to calculate project or leakage CO_2 emissions from fossil fuel combustion".

Project participants may choose between two options to determine the emissions from the remaining emission sources ($E_{Flaring,i,j,x,y}$, $E_{Venting,i,j,x,y}$, $E_{Leaks,i,j,x,y}$, $E_{Storage\ Losses,i,j,x,y}$, $E_{Fugitive,i,j,x,y}$):

- Option (i): use the applicable Tier 2 or 3 calculation procedures in the IPCC 2006 Guidelines;[4] or
- Option (ii): reference the emission rate from reputable published emissions inventories where these exist (for example, country-specific and industry-specific emission inventories published by national reporting entities and industry associations, confirming that these have been developed using a IPCC Tier 2 or Tier 3 approach).

[4] *Volume 2 - Energy* of the *IPCC 2006 Guidelines* is designed to assess GHG emissions contributions from sources that include those associated with an upstream emission stage. The guidelines provide separate procedures for assessing GHG emission contributions due to fugitive emissions and energy use. Methods for estimating fugitive emissions are provided in *Volume 2, Chapter 4 - Fugitive Emissions*. To apply a Tier 2 or Tier 3 methodology to a specific emissions stage requires determining the amount of fossil fuel and purchased electric power consumption by that stage, as well as the relevant activity data (such as the technology associated with venting, flaring, storage losses, and fugitive equipment leaks). For coal mining the method involves applying country or mine specific emission factors to the mining and ore preparation stages. For oil and natural gas systems, it is necessary to apply more complicated procedures involving bottom-up approaches. Examples of these are referenced in the IPCC 2006 Guidelines, such as the API Compendium and similar guidelines published by other relevant industry associations.

Document in the CDM-PDD and monitoring reports:

- Activities within the stage that are associated with each emission source, and boundary of, the upstream emissions stage *i* (to assist with this, information is given in Table 3 about potential activities and emission sources that occur within each upstream emissions stage); and
- The calculation of emissions for each emission source.

III. MONITORING METHODOLOGY

Monitoring Procedures

No monitoring is required for application of this tool.

IV. SUMMARY DATA PARAMETER TABLES

Data / Parameter:	NCV_x
Data unit:	TJ / t
Description:	Net calorific value of the fossil fuel *x*
Source of data:	Use IPCC default net calorific values (country-specific, if available), that reasonably represent local circumstances. Choose the values in a conservative manner and justify the choice
Value applied	Table 1.2 of Volume 2 – Energy, IPCC 2006 Guidelines, converting values to TJ / t
Any comment:	---

Data / Parameter:	$DT_{i,j,x,r,t}$
Data unit:	km
Description:	Distance that fossil fuel *x* from fuel origin *j* was transported by mode *r* in upstream emissions stage *i* in the time period *t*
Source of data:	Relevant transportation statistics may be available from national statistics or transportation departments, or from relevant trade associations
Value applied	Document the basis for the applied values
Any comment:	GHG emissions from international shipping must be ignored, because they are excluded from reduction targets under the Kyoto Protocol. Thus, exclude the length of any international transportation segments when assessing the value of $DT_{i,j,x,r,t}$

Data / Parameter:	$FP_{i,j,x,y}$
Data unit:	TJ / yr
Description:	Fuel output from upstream emissions stage *i* of fossil fuel type *x* from fossil fuel origin *j* in the time period *t*
Source of data:	Relevant production statistics may be available from national statistics or energy departments, or from relevant trade associations
Value applied	Document the basis for the applied values
Any comment:	---

V. REFERENCES

Alberta Energy Research Institute. 2009. Life Cycle Assessment Comparison of North American and Imported Crudes Prepared by Jacobs Consultancy and Life Cycle Associates LLC.

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ANNEX 1: DEFAULT EMISSION FACTORS FOR UPSTREAM EMISSIONS STAGES

Information about potential key activities and emission sources that occur within each upstream emissions stage is presented in Table 3 for context. This information can also assist with the determination of refined emission factors, if the project proponent selects this option instead of using default emission factors.

Table 3: Default upstream emission factors presented by upstream emissions stage for each type of fossil fuel

[Please note: The default emission factors in the table below, intended to be averages, as well as the upstream emission stages applicable to each fuel type will undergo a peer review. Therefore there is potential that they may change. Comments that could be taken into account in this peer review, such as on the information sources referenced, are welcome.]

Fossil fuel type x	Potential upstream emissions stage i	Potential key activities undertaken	Typical relative emission contributions by type of emission source			Default Emission Factor	Mand-atory stage	Option to calculate refined emission factor	Reference
			Fossil fuel consumption	Electric power consumption	Fugitives	(t CO2e / TJ)			
Natural Gas (NG)	NG Exploration & Production *(mandatory stage)*	Drilling, well testing & servicing, field gas gathering (including compression and hydrate control), and produced water separation and disposal, plus associated gas conservation at oil production facilities	Moderate to High	Zero to moderate	Small to moderate	1.9 to 2.8[1]	yes	yes	Centre for Liquefied Natural Gas (2009) and CAPP (2004)
	NG Processing	Separation, sweetening, dehydration, hydrocarbon dew point control, produced water disposal and compression	Moderate to High	Zero to moderate	Small to moderate	16.1	no	yes	Centre for Liquefied Natural Gas (2009)
	NG Transmission	Transport of market-ready NG using high pressure pipeline systems	Moderate to High	Small	Small to moderate	6.4	no	yes	Centre for Liquefied Natural Gas (2009)

	NG Storage	NG re-compression back into the transmission system and potentially dehydration and processing	Moderate to High	Small to moderate	Small to moderate	1.6	no	yes	Unpublished data from industry
	NG Distribution	Pressure letdown from the transmission system and transport in medium and low pressure pipelines to the end users	Zero to small	Zero to small	Small to moderate	0.7 to 1.6[2]	no	yes	IPCC (2006)
Natural Gas Liquids (NGL)	NGL Exploration & Production *(mandatory stage)*	Storage of NGL at field facilities and gas processing plants, as well as transportation to central facilities (i.e., by truck, rail, ship and/or pipelines)	Small to moderate	Zero to small	Moderate	1.3	yes	yes	Calculated based on unpublished industry data
	NGL Stabilization & Treating	Vapour pressure control and potentially treating to remove reduced sulphur compounds.	Small to moderate	Zero to small	Small to moderate.	2.1	no	yes	Assumed to be the same as a de-butanizer
	NGL Transportation *(mandatory stage)*	Potentially by truck, rail, ship and/or pipelines	Small to moderate	Small to moderate	Nil.	1.1 to 2.8[3]	yes	yes	AERI(2009)
Liquefied Natural Gas (LNG)	NG Exploration & Production *(mandatory stage)*	Drilling, well testing & servicing, field gas gathering (including compression and hydrate control), and produced water separation and disposal, plus associated gas conservation at oil production facilities	Moderate to High	Zero to moderate	Small to moderate	1.9	yes	yes	Centre for Liquefied Natural Gas (2009)
	NG Processing	Separation, sweetening, dehydration, hydrocarbon dew point control, produced water disposal and compression	Moderate to High	Zero to moderate	Small to moderate	16.1	no	yes	Centre for Liquefied Natural Gas (2009)

	NG Transmission	Transport of market-ready NG using high pressure pipeline systems	Moderate to High	Small	Small to moderate	6.4	no	yes	Centre for Liquefied Natural Gas (2009)
	NG Liquefaction & LNG Storage *(mandatory stage)*	Compression, refrigeration, expansion cooling, storage and management of boil-off losses	Moderate to High	Small to moderate	Small to moderate	4.8 to 13.3[4]	yes	yes	Jaramillo et al. (50.6 at Q1)
	LNG Transportation *(mandatory stage)*	Tanker fuel and management of boil-off losses	Small to moderate	Small	Small to moderate	5.9	yes	yes	Centre for Liquefied Natural Gas (2009)
	LNG Vaporization & Compression *(mandatory stage)*	Vaporization through heat addition and re-compression of the produced gas	Moderate	Small	Small to moderate	0.8	yes	yes	Centre for Liquefied Natural Gas (2009)
	NG Transmission	Transport of market-ready NG using high pressure pipeline systems	Moderate to High	Small	Small to moderate	6.4	no	yes	Centre for Liquefied Natural Gas (2009)
	NG Distribution	Pressure letdown from the transmission system and transport in medium and low pressure pipelines	Zero to small	Zero to small	Small to moderate	0.7 to 1.6[2]	no	yes	IPCC (2006)
Compressed Natural Gas (CNG)	NG Exploration & Production *(mandatory stage)*	Drilling, well testing & servicing, field gas gathering (including compression and hydrate control), and produced water separation and disposal, plus associated gas conservation at oil production facilities	Moderate to High	Zero to moderate	Small to moderate	2.8	yes	yes	Centre for Liquefied Natural Gas (2009) and CAPP (2004).

	NG Processing	Separation, sweetening, dehydration, hydrocarbon dew-point control, produced water disposal and compression	Moderate to High	Zero to moderate	Small to moderate	16.1	no	yes	Centre for Liquefied Natural Gas (2009)
	NG Transmission	Transport of market-ready NG using high-pressure pipeline systems	Moderate to High	Small	Small to moderate	6.4	no	yes	Centre for Liquefied Natural Gas (2009)
	NG Storage	Re-compression and potentially dehydration and processing	Moderate to High	Small to moderate	Small to moderate	N/A	no	yes	Unpublished data from industry.
	NG Distribution *(mandatory stage)*	Pressure letdown from the transmission system and transport in medium- and low-pressure pipelines	Zero to small	Zero to small	Small to moderate	0.7 to 1.6[2]	yes	yes	IPCC (2006)
	Production of CNG at the final sales point. *(mandatory stage)*	NG compression from an inlet pressure of 35 to 2070 kPag up to final pressure of 20,700 kPag	Nil	Small to moderate	Small	2.9	yes	yes	Calculated based on default factor of 1.3 tCO2/MWh from CDM Tool (am-tool-05-v1)

Light Fuel Oil (Diesel)	Crude Oil Exploration & Production *(mandatory stage)*	Drilling, well servicing, artificial lift systems, enhanced recovery (e.g., through secondary and tertiary recovery schemes), transport to central treating facilities (i.e., by truck or pipeline) for solids and water removal, water disposal, waste gas disposal, oil sands mining and extraction, bitumen and heavy oil dilution and/or heating	Moderate to high	Zero to high	Small to high	2.5 to 20.4[5]	yes	no	ICF (2011)
	Crude Oil Transportation	Transport of treated crude oil (including heavy oil and bitumen) to upgraders and/or refineries by truck, rail, ship and/or pipeline, plus (where applicable) diluent recycle	Zero to moderate	Zero to moderate	Nil.	1.1 to 2.8[6]	no	no	AERI(2009)
	Petroleum Upgrading and/or Refining *(mandatory stage)*	Salt removal, distillation, carbon rejection and/or hydrogen addition, followed by product fractionation, storage and blending	Moderate to large	Moderate	Small to moderate	12.0 to 21.4[7]	yes	yes	AERI(2009)
	Refined Product Distribution *(mandatory stage)*	Transport to bulk terminals and to retail distribution sites by truck, rail, ship and/or pipeline	Zero to moderate	Zero to small	Nil	0.9	yes	yes	Assumed to be the same as for gasoline

Heavy Fuel Oil (Bunker or Marine Type)	Crude Oil Exploration & Production *(mandatory stage)*	Drilling, well servicing, artificial lift systems, enhanced recovery (e.g., through secondary and tertiary recovery schemes), transport to central treating facilities (i.e., by truck or pipeline) for solids and water removal, water disposal, waste gas disposal, oil sands mining and extraction, bitumen and heavy oil dilution and/or heating	Moderate to high	Zero to high	Small to high	2.5 to 20.4[5]	Yes	no	ICF (2011)
	Transportation	Transport of treated crude oil (including heavy oil and bitumen) to upgraders and/or refineries by truck, rail, ship and/or pipeline	Zero to moderate	Zero to moderate	Nil	1.1 to 2.8[6]	no	no	AERI(2009)
	Upgrading or Refining *(mandatory stage)*	Salt removal, distillation, carbon rejection and/or hydrogen addition, followed by product fractionation, storage and blending	Moderate to large	Moderate	Small to moderate	4.1	yes	yes	Toyoto Motor Corporation (2004)
	Distribution *(mandatory stage)*	Transport to bulk terminals and to retail distribution sites by truck, rail, ship and/or pipeline	Zero to moderate	Zero to small	Nil	0.9	yes	yes	Assumed to be the same as for gasoline

Gasoline	Crude Oil Exploration & Production *(mandatory stage)*	Drilling, well servicing, artificial lift systems, enhanced recovery (e.g., through secondary and tertiary recovery schemes), transport to central treating facilities (i.e., by truck or pipeline) for solids and water removal, water disposal, waste gas disposal, oil sands mining and extraction, bitumen and heavy oil dilution and/or heating	Moderate to high	Zero to high	Small to high	2.5 to 20.4[5]	yes	no	ICF (2011)
	Transportation	Transport of treated NGL and crude oil (including heavy oil and bitumen) to upgraders and/or refineries by truck, rail, ship and/or pipeline	Zero to moderate	Zero to moderate	Nil	0.9 to 2.8[6]	no	no	ICF (2011)
	Upgrading and/or Refining *(mandatory stage)*	Salt removal, distillation, carbon rejection and/or hydrogen addition, followed by product fractionation, storage and blending	Moderate to large	Moderate	Small to moderate	9.3 to 12.9[7]	yes	yes	ICF (2011)
	Distribution *(mandatory stage)*	Transport to bulk terminals and to retail distribution sites by truck, rail, ship and/or pipeline	Zero to moderate	Zero to small	Nil	0.9	yes	yes	ICF (2011)

Kerosene (household and aviation)	Crude Oil Exploration & Production *(mandatory stage)*	Drilling, well servicing, artificial lift systems, enhanced recovery (e.g., through secondary and tertiary recovery schemes), transport to central treating facilities (i.e., by truck or pipeline) for solids and water removal, water disposal, waste gas disposal, oil sands mining and extraction, bitumen and heavy oil dilution and/or heating	Moderate to high	Zero to high	Small to high	2.5 to 20.4[5]	yes	no	ICF (2011)
	Transportation	Transport of treated NGL and crude oil (including heavy oil and bitumen) to upgraders and/or refineries by truck, rail, ship and/or pipeline	Zero to moderate	Zero to moderate	Nil	1.1 to 2.8[6]	no	no	AERI(2009)
	Upgrading and/or Refining *(mandatory stage)*	Salt removal, distillation, carbon rejection and/or hydrogen addition, followed by product fractionation, storage and blending	Moderate to large	Moderate	Small to moderate	1.9	yes	yes	Toyoto Motor Corporation (2004)
	Distribution *(mandatory stage)*	Transport to bulk terminals and to retail distribution sites by truck, rail, ship and/or pipeline	Zero to moderate	Zero to moderate	Nil	0.9	yes	yes	Assumed to be the same as for gasoline

Propane & Butane	Processing of High Vapour Pressure Product Streams at Gas Plants, Upgraders and Refineries *(mandatory stage)*	Fractionation (e.g., de-propanizer and/or debutanizer) and storage	Moderate	Small	Nil	*[To be determined]*	yes	yes	Derived from depropanizer and debutanizer data published by Summers et al (2002) and Chen and Lin (2001)
	Distribution *(mandatory stage)*	Transport to bulk terminals and to retail distribution sites by truck, rail, ship and/or pipeline	Zero to moderate	Zero to moderate	Nil.	*[To be determined]*	yes	yes	Assumed to be the same as for gasoline
Coal	Mining *(mandatory stage)*	Mining equipment, seam gas drainage and disposal before and during mining, water drainage and disposal, post mine seam gas emissions, uncontrolled combustion and burning coal dumps.	Moderate	Moderate	Moderate	18.9 (Underground Mines) 3.3 (Surface Mines)	yes	Only if fossil fuel origin is not *global*	Derived from industry fuel use data and maximum IPCC (2006) default CH4 emission Factors
	Ore Processing *(mandatory stage)*	Crushing, screening, cleaning, drying, disposal of rejects and tailings management	Zero to moderate	Moderate	Small		yes	yes	

	Transportation	By truck, rail or barge	Moderate	Zero to small	Nil	2.5	no	yes	Based on 1000 km transport by truck and 6000 km by marine vessel. Truck and marine vessel factors derived from CEFIC (2011)
Lignite	Mining *(mandatory stage)*	Mine mobile equipment, seam gas drainage and disposal before and during mining, water drainage and disposal, post mine seam gas emissions, uncontrolled combustion and burning coal dumps	Moderate	Moderate	Moderate	3.4	yes	Only if fossil fuel origin is not *global*	Derived from industry fuel use data and maximum IPCC (2006) default CH4 emission Factors
	Ore Processing *(mandatory stage)*	Crushing, screening, cleaning, drying, disposal of rejects and tailings management	Zero to moderate	Moderate	Small		yes	yes	
	Transportation	By truck, rail or barge	Moderate	Zero to small	Nil	2.6	no	yes	Based on 500 km transport by truck. Truck factor derived from CEFIC (2011)

1. The emissions intensity of natural gas exploration and production will depend largely on the amount of compression required by the field gas gathering system and this will increase with time as the reservoir pressures decline. For shallow gas production (wells <1000 m deep), associated gas production and deep gas production (wells ≥1000 m deep) from gas fields more than 10 years old use the greater emission factor value. For deep gas production from gas fields less than 10 years old use the lower emission factor value. In the absence of relevant information, apply the average value.

2. The emissions intensity of the natural gas distribution system will depend largely on the type of piping that is used. Interpolate between the two emission factors based on the percentage of the piping that is constructed of cast iron pipe. In the absence of relevant information, apply the average value.

3. The emissions intensity of NGL transportation activities will depend partly on the mode of transportation, but mostly on the transportation distance. For local transportation (intra-state or intra-province) apply the lower emission factor value. For imports, exports and national transportation systems use the greater emission factor value. In the absence of relevant information, apply the average value.

4. The emission intensity of natural gas liquefaction and LNG storage will depend on a variety of factors including the natural gas supply pressure and composition, the scale and design of the liquefaction plant, the time in storage and the systems used to manage boil-off losses. For modern plants (<10 years old) in Annex I countries use the lower emission factor and use the higher emission factor for plants that are more than 10 years old or located outside of an Annex I country. In the absence of relevant information, apply the average value.

5. The fuel–specific emission intensity of crude oil exploration and production activities will depend on the type and ultimate refining yield of the fuel feedstock, as well as the type of feedstock (e.g., crude oil, synthetic crude oil, NGL, bitumen or heavy oil), the feedstock production method, the amount of water production and the water disposal method. The oil-to-water ratio will tend to increase as the reservoir is depleted. For any enhanced recovery techniques (e.g., thermal techniques, water floods, miscible CO_2 floods, fire floods, solvent extraction methods, etc.) use the greater emission factor. For other recovery techniques use the lower emission factor. In the absence of relevant information, apply the average value.

6. The emissions intensity of NGL or crude oil transportation activities will depend partly on the mode of transportation, but mostly on the transportation distance. For local transportation (i.e., intra-state or intra-province) apply the lower emission factor value. For imports, exports and national transportation systems use the greater value. In the absence of relevant information, apply the average value.

7. The emission intensity of petroleum upgrading and refining will depend largely on the degree of upgrading and/or refining that is performed, and the composition of the crude oil feedstock. Interpolate between the two factors based on the percentage of the feedstock originating from heavy oil or crude bitumen. In the absence of relevant information, apply the average value.

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History of the document

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