EIB Project Carbon Footprint Methodologies

Methodologies for the assessment of project greenhouse gas emissions and emission variations

Version 11.3

January 2023

European Investment Bank

The EU bank

EIB Project Carbon Footprint Methodologies

Methodologies for the assessment of project greenhouse gas emissions and emission variations

Version 11.3

January 2023

European Investment Bank

The EU bank

Note to readers

Carbon emissions result from virtually all human and natural activities. For example, even when the best available technologies are used when making cement, paper or steel, inevitably a significant quantity of CO_2 is emitted. The carbon footprint measures greenhouse gas (GHG) emissions. However, evaluating the merit of a project requires comparing the economic costs to the benefits, including the costs and benefits in terms of incremental GHG emissions. Where appropriate, the European Investment Bank (EIB) uses an economic (shadow) price of carbon to convert changes in tonnes of GHG into euros. In short, whilst the carbon footprint is an important metric in its own right, it should be viewed within the context of the overall economic appraisal of a project.

The recommended methodologies are by assumption restricted in scope. The carbon footprint does not purport to be a comprehensive life cycle analysis of a project. Such an exercise can only be done credibly ex-post and with a large amount of information. The carbon footprint calculation takes place ex-ante and with limited information and resources. For instance, downstream emissions that will occur due to the use of the products and services resulting from EIB-financed investment projects are generally not considered. Examples include research and development projects in the area of efficient engines, a project to build a solar panel or wind turbine factory, and a bioethanol refinery project.

In considering the scope and nature of EIB carbon footprint methodologies, readers should be mindful that the carbon footprint of a project in itself cannot and should not be construed as an expression of the merit or value of that project, either broadly or more narrowly in climate change terms alone.

Lastly, the EIB carbon footprint methodology is considered work in progress that is subject to periodic review and revision in the light of experience gained and as knowledge of climate change issues evolves. The EIB's Projects Directorate welcomes comments and suggestions for improvement on the latest draft of the present document.

EIB Project Carbon Footprint Methodologies

For further information on the EIB's activities, please consult our website, www.eib.org.
You can also contact our info Desk, info@eib.org.

European Investment Bank
98-100, boulevard Konrad Adenauer
L-2950 Luxembourg
+352 4379-1
info@eib.org
www.eib.org
twitter.com/eib
facebook.com/europeaninvestmentbank
youtube.com/eibtheeubank

Published by the European Investment Bank.

Printed on FSC® Paper.

REVISION HISTORY

Revision No.	Issue Date	Amendment Description
v1	10 July 2009	First version issued following consultations on two draft editions
v2	10 Sept 2009	Revisions to incorporate changes following internal review
v3	24 Sept 2009	Revisions to incorporate changes following launch of methodologies
v4	22 Oct 2009	Revisions following implementation of methodologies
v5	10 Nov 2009	Revisions to include amended baseline methodologies
v6	23 Nov 2009	Revisions following internal review
v7	24 Feb 2010	Revisions following internal review
v8	15 July 2010	Revision following internal review and comments
v9.1	29 Sept 2010	Revision following internal review and comments
v9.2	Q1 2012	Holding version after preliminary review by the Carbon Footprint Task Force issued before CSO (civil society organisations) Workshop
v10	Q3 2012	Revision following feedback from PJ CFTF,[1] CSOs, MDB (multilateral development banks) Working Group and the completion of the 3-year pilot
v10.1	Q1 2014	Table A1.3 updated with IEA (International Energy Agency) data for the 3-year average, 2009-2011
v10.2 (internal)	Q4 2014	Revisions following CO_2 logic review of v10 and KPMG audit of CFE 2013
v10.3 (internal)	Q2 2016	Table A1.3 updated with IEA data for 3-year average (2011-2013)
v10.4 (internal)	Q4 2017	Improved clarification of absolute and relative boundaries, updated Table A1.3
v11	Q4 2018	Revision of threshold for absolute emissions Including methodologies for ports, airports and forestry Improved definition of scopes and boundaries Updated emission factors Alignment with IFI Framework for a Harmonised Approach to Greenhouse Gas Accounting
v11.1	Q3 2020	Clarification of emission factors for biomass, emissions from purchased renewable electricity and emissions from iron and steel production Improvements to forestry methodology Explanation of the EX-ACT tool for land-use change carbon balance calculation Updated emission factors for electricity
v11.2	Q1 2022	Clarification of emissions from purchased renewable electricity Improved methodologies for electric and hybrid vehicles Updated emission factors for electricity Updated emission calculation for wastewater treatment
V11.3	Q1 2023	Textual improvements Clarification on the use of thresholds for the carbon footprint exercise and for allocations under framework loans

[1] The Carbon Footprint Task Force is a group comprised of experts from each department in the EIB's Project Directorate tasked with reviewing sector methodologies and undertaking the quality assurance of project carbon footprints.

Contents

1. Introduction

This document contains the European Investment Bank's (EIB) carbon footprinting methodology. It provides guidance to EIB staff on how to calculate the carbon footprint of EIB-financed investment projects. The document also presents how the EIB calculates the carbon footprint of its investment projects for its auditors, external stakeholders and other interested parties.

The methodology is used to calculate the carbon footprint of the investment projects financed by the EIB. These carbon footprints are published on the project's environmental and social data sheet. The EIB also publishes the aggregated results annually in the EIB Group's Sustainability Report as part of its Carbon Footprint Exercise (CFE).

Whilst project carbon footprinting is mainstreamed into the Bank's operations, it remains under regular review. The Bank works closely with other financial institutions and stakeholders in its footprinting work and welcomes further feedback on the methodology. The EIB's methodology is in line with the International Financial Institutions (IFI) Framework for a Harmonised Approach to Greenhouse Gas Accounting, published in November 2015, and version 02.0 of the IFI Guideline for a Harmonised Approach to Greenhouse Gas Accounting, published in June 2021.
The methodologies presented here are for project carbon footprinting and should not be confused with the internal carbon footprint of the EIB Group's travel and buildings, which is reported separately. In addition, the carbon footprinting methodology should not be confused with the *European Investment Bank Climate Action - Eligible sectors and eligibility criteria*, which can be found separately on the EIB's website.

2. Background

Most projects financed by the EIB emit greenhouse gases (GHG) into the atmosphere either directly (e.g. through fuel combustion or production process emissions) or indirectly (e.g. through purchased electricity and/or heat). In addition, many projects result in emissions reductions or increases when compared to what would have happened in the absence of the project, which are referred to as baseline emissions.

The EIB's Carbon Footprint Exercise includes direct investment loans and large framework loan allocations that cross the significant emissions thresholds defined in Section 5 of the methodologies. Other intermediated lending is not currently included due to the limited information available to carry out a meaningful calculation for numerous sub-projects.

This document sets out the methodologies to calculate these projects' carbon footprints. The methodologies enable two measures of GHGs from investment projects financed by the Bank to be estimated:

- the absolute GHG emissions or sequestration of the project, and;
- the emissions variation of the project, in other words, the relative GHG emissions of the project, which is the difference in emissions between the "with" and "without" project scenarios. Relative emissions can be either positive or negative, based on whether there is an increase or decrease in emissions.

The methodologies set out below are based upon the internationally recognised Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories, the World Resource Institute (WRI) and World Business Council for Sustainable Development (WBCSD) GHG Protocol Corporate Accounting and Reporting Standard and the International Financial Institutions (IFI) Framework for a Harmonised Approach to Greenhouse Gas Accounting. In the absence of project-specific factors, the methodologies adopt an IPCC factor applicable at the global or trans-national level (termed Tier 1). The development of the methodologies has also been informed by ISO 14064 Parts 1 and 2 and the Verified Carbon Standard which provide guidelines for the development of greenhouse gas inventories at the corporate and project levels.

3. Objective

The EIB calculates and reports the carbon footprints of the projects it finances to provide transparency on the GHG emissions footprints of its financing activities. The GHG footprint of an individual investment project is reported in its environmental and social data sheet. Aggregated results are reported as part of the annual Carbon Footprint Exercise (CFE) published in the EIB Group's Sustainability Report.

4. Guiding principles

Certain principles underpin the estimation of project-based absolute and relative GHG emissions. These principles should guide users in cases where the EIB methodologies afford flexibility or discretion, or where a particular situation requires the application of a case-specific factor. The application of these principles will help ensure the credibility and consistency of efforts to quantify and report emissions. These principles are listed below.

Completeness

All relevant information should be included in the quantification of a project's GHG emissions and in the aggregation of the total EIB-induced GHG footprint. This ensures that there are no material omissions from the data and information that would substantively influence the assessments and decisions of the users of the emissions data and information.

Consistency

The credible quantification of GHG emissions requires that methods and procedures are always applied to a project and its components in the same manner, that the same criteria and assumptions are used to evaluate significance and relevance, and that any data collected and reported allow for meaningful comparisons over time.

Transparency

GHG emissions are assessed for individual investment projects, with emissions calculated according to the EIB methodologies during the appraisal reported in the project's environmental and social data sheet, which is published on the EIB's website in the public register.

For the purposes of annual reporting in the CFE, the project figures are prorated in proportion to the EIB funding for the project (financed contract amounts signed in that year compared to its total investment costs). Thus, if the EIB signs a contract for 25% of a project in a particular year, 25% of the project emissions will be reported in that year. Further contracts may be signed for the same project in subsequent years and will be accounted for separately in the respective year, again using a prorated approach based on the finance contract amount in that year, ensuring that there is no double counting of the impact of a project.

Clear and sufficient information should be available to allow for the credibility and reliability of reported GHG emissions to be assessed. Specific exclusions or inclusions should be clearly identified and assumptions should be explained. Appropriate references should be provided for both data and assumptions. Information relating to the project boundary, the explanation of the baseline choice, and the estimation of baseline emissions should be sufficient to replicate results and comprehend the conclusions drawn.

Conservativeness

The EIB should use conservative assumptions, values and procedures. Conservative values and assumptions are those that are more likely to overestimate absolute emissions and "positive" relative emissions (net increases) and underestimate "negative" relative emissions (net reductions).

Balance

Objective threshold values are used to determine which investment projects are included in the portfolio carbon footprint. This includes investment projects with positive as well as negative impacts.

Accuracy

Carbon footprinting involves many forms of uncertainty, including uncertainty about the identification of secondary effects, the identification of baseline scenarios, and baseline emission estimates. Therefore, GHG estimates are, in principle, approximate. Uncertainties with respect to GHG estimates or calculations should be reduced as far as is practical, and estimation methods should avoid bias. Where accuracy is reduced, the data and assumptions used to quantify GHG emissions should be conservative.

Relevance

GHG sources, GHG sinks, GHG reservoirs, data and methodologies appropriate to the needs of the intended user should be selected.

5. Significant emissions

Not all investment projects require a carbon footprint assessment to be undertaken. Only investment projects with significant emissions must be assessed according to the EIB methodologies, and these carbon footprints are included in the CFE. Based on the results of the GHG footprint pilot, it was decided to set minimum project thresholds for inclusion in the GHG footprint at 100 000 tonnes CO_2e/year for absolute emissions and 20 000 tonnes CO_2e/year (positive or negative) for relative emissions. Investment projects were included if either of the thresholds is crossed. When included, both absolute and relative emissions need to be calculated and reported.

The coverage of these thresholds was reassessed in 2018, and the threshold for absolute emissions was lowered to guarantee the desired level of coverage for the EIB. The thresholds are as follows:

- Absolute emissions or carbon sequestration exceeding 20 000 tonnes CO_2e/year
- Relative emissions exceeding 20 000 tonnes CO_2e/year (positive or negative)

Research indicates that they capture approximately 95% of the absolute and relative GHG emissions from projects. Investment projects with absolute and relative emissions that do not cross these thresholds are not included in the footprint since they are not considered significant.

Table 1 below illustrates the project types that may be included in the calculation of the CFE. This list and categorisation are for guidance only. Project teams may use a quantitative assessment, expert knowledge based on previous projects, or other published sources to determine whether a project is likely to be above or below the threshold. Where there is uncertainty, the full carbon footprint calculation should be undertaken to assess whether the project should be included in the CFE.

The EIB reports 100% of a project's emissions in the ESDS even if the Bank is only contributing a portion of the total project investment cost. At the CFE reporting stage, the results are prorated to the EIB's share of the financing plan.

Table 1: Illustrative examples of project categories for which a GHG assessment is required

In general, depending on the scale of the project, a GHG assessment IS NOT required	• Telecommunications services • Drinking water supply networks • Rainwater and wastewater collection networks • Small-scale industrial wastewater treatment and municipal wastewater treatment • Property developments (including infrastructure such as social housing, schools and hospitals) • Mechanical/biological waste treatment plants • R&D activities • Pharmaceuticals and biotechnology • Mobile asset projects, trams and bus rapid transit systems
In general, a GHG assessment IS required	• Municipal solid waste landfills • Municipal waste incineration plants • Large wastewater treatment plants • Manufacturing industry • Chemicals and refining • Mining and basic metals • Pulp and paper • Rolling stock (including metros and larger train fleets), ships, transport fleet purchases • Road and rail infrastructure • Power transmission lines • Renewable sources of energy • Fuel production, processing, storage and transportation • Cement and lime production • Glass production • Heat and power-generating plants • District heating networks • Natural gas liquefaction and regasification facilities • Gas transmission infrastructure

6. Greenhouse gases included in the carbon footprint

The GHGs included in the footprint include the seven gases listed in the Kyoto Protocol, namely: carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulphur hexafluoride (SF6) and nitrogen trifluoride (NF3). The GHG emissions quantification process converts all GHG emissions into tonnes of carbon dioxide called CO2e (equivalent) using the Global Warming Potentials (GWP), which can be found in Table A1.9 in the Annex.

All of the EIB's footprints, both absolute and relative, include these seven GHGs and are expressed in tonnes of CO2e, as far as data availability allows.

The following processes/activities usually generate GHGs that may be accounted for using the following methodologies:

- CO_2 — stationary combustion of fossil fuels, indirect use of electricity, oil/gas production and processing, flue gas desulphurisation (limestone-based), aluminium production, iron and steel production, nitric acid production, ammonia production, adipic acid production, cement production, lime production, glass manufacture, municipal solid waste incineration, transport (mobile combustion)[2]
- CH_4 — biomass decomposition, oil/gas production and processing, coal mining, municipal solid waste landfill, municipal wastewater treatment
- N_2O — stationary combustion of fossil fuels/biomass, nitric acid production, adipic acid production, municipal solid waste incineration, municipal wastewater treatment, transport (mobile combustion)
- HFCs — refrigeration/air conditioning/insulation industry
- PFCs — aluminium production
- SF_6 — electricity transmission systems, specific electronics industries (e.g. LCD display manufacture)
- NF_3 — plasma and thermal cleaning of Chemical Vapour Deposition (CVD) reactors

Table 2: Selected examples of sources of direct GHG emissions by activity type

ACTIVITY	GHG TYPE	POTENTIAL SOURCES OF EMISSIONS
COMBUSTION FOR ENERGY	CO_2 N_2O CH_4	Energy-related GHG emissions from combustion: boilers; burners; turbines; heaters; furnaces; incinerators; kilns; ovens; dryers; engines; flares; any other equipment or machinery that uses fuel, including vehicles
COMBUSTION GAS SCRUBBERS	CO_2	Process CO_2 from flue gas desulphurisation (limestone-based) units
OIL/GAS PRODUCTION, PROCESSING & REFINING	CO_2 N_2O CH_4	Energy-related GHG emissions from combustion: boilers; process heaters and treaters; internal combustion engines and turbines; catalytic and thermal oxidisers; coke calcining kilns; firewater pumps; emergency or standby generators; flares; incinerators; crackers Process-related GHGs from: hydrogen production installations; catalytic regeneration (from catalytic cracking and other catalytic processes); cokers (flexi-coking, delayed coking) Fugitive emissions of CH_4

[2] Note that emissions from the combustion of biomass in power generation, industry, waste treatment or transport fuels, for example, are considered zero. See footnote 3 and the associated explanation earlier in the text.

ACTIVITY	GHG TYPE	POTENTIAL SOURCES OF EMISSIONS
IRON & STEEL PRODUCTION	CO_2 N_2O	1) Blast furnace/basic oxygen furnace route (BF/BOF): iron ore into steel 2) Direct reduction route (DR): iron ore to direct reduced iron (DRI) 3) Electric arc furnace route (EAF): steel recycling route steel scrap or DRI into steel Sources for 1: BF/BOF 1) Coking plant: transformation of coal to coke; sources: coal and some conventional fuels but limited; output emissions: coke oven gas (COG) 2) Sinter plant/pelletisation: transformation of lump iron ore into sinter or pellets, which is a modified form of iron ore; sources: mainly natural gas and to some degree coke and/or off gases available in the steel plant 3) Blast furnace: transformation from iron ore to pig iron; sources: coke (coming from the coke plant) and coal (pulverised coal injection) and/or natural gas, and/or alternative non-renewable fuels, and process emissions related to the reduction of iron ore 4) Steel shop — basic oxygen furnace (BOF): transformation from pig iron to steel; sources: process emissions related to burning carbon or other elements contained in the pig iron and from burning electrodes (BOFG) COG/BFG/BOFG are mixtures containing N_2, CO, CO_2 and H_2 typically used to fire an electrical power plant. Sources for 2: EAF 1) EAF: transformation from scrap or DRI to steel; sources: electricity from the grid, mainly, and to some degree firing of natural gas and emissions from burning electrodes Sources for 3: DRI processes 1) Different DRI reactors: transformation from iron ore into direct reduced iron (DRI; sources: coal and process emissions or natural gas and process emissions 2) Second step is melting DRI in an EAF, which is described in (2) direct reduction route.
CEMENT & LIME MANUFACTURE	CO_2	Calcination of limestone in the raw materials; conventional fossil kiln fuels; alternative fossil-based kiln fuels and raw materials; refuse-derived fuel (RDF); non-kiln fuels; organic carbon content of limestone and shales; raw materials used for waste gas scrubbing
GLASS PRODUCTION	CO_2	Glass production: decomposition of alkali and earth alkali carbonates during the melting of the raw material; conventional fossil fuels; alternative fossil-based fuels and raw materials; other fuels; carbon-containing additives, including coke and coal dust; waste gas scrubbing
PAPER & PULP MANUFACTURE	CO_2	Pulp and paper manufacture: power boilers, gas turbines, and other combustion devices producing steam or power for the mill; recovery boilers and other devices burning/recycling spent pulping liquors; incinerators; lime kilns and calciners; waste gas scrubbing; fossil fuel-fired dryers (such as infrared dryers). Fuels predominantly process by-products and rejects, such as bark and biomass, and to a lesser extent natural gas and other fossil fuels. The recycled paper sector also typically valorises the pulp process waste that is a mix of cellulose and plastics. The processes wastewater treatment may generate diffuse methane slip from anaerobic digestion.

ACTIVITY	GHG TYPE	POTENTIAL SOURCES OF EMISSIONS
ALUMINIUM PRODUCTION	CO_2 PFCs SF_6	CO_2 from combustion sources Process-related GHG emissions: CO_2 from anode consumption (pre-baked or Søderberg); CO_2 from anode and cathode baking; PFCs from anode effects (or events). Other process-related emissions that may occur, depending on the facility configuration, include: CO_2 from coke calcinations; SF_6 from use as a cover gas; SF_6 from use in on-site electrical equipment.
NITRIC ACID PRODUCTION	CO_2 N_2O	CO_2 from combustion sources and process-related
AMMONIA PRODUCTION	CO_2	CO_2 from combustion sources and process-related
ADIPIC ACID PRODUCTION	N_2O	CO_2 from combustion sources and process-related
WASTEWATER TREATMENT	CH_4 CO_2 N_2O	CH_4 from degradation of organic material in wastewater under anaerobic conditions CO_2 emissions from the consumption of electricity in the treatment process N_2O as an intermediate product from the degradation of nitrogen components in wastewater
MUNICIPAL SOLID WASTE INCINERATION	CO_2 N_2O	GHGs from MSW (municipal solid waste) combustion
MUNICIPAL SOLID WASTE LANDFILLS	CH_4	CH_4 from anaerobic digestion of biodegradable waste
REFRIGERATION/AIR CONDITIONING/INSULATION INDUSTRY	HFCs	Fugitive emissions of HFCs
POWER TRANSMISSION	SF_6	Transmission losses will be derived from power production combustion sources and have an associated emission of CO_2. Fugitive emissions of SF_6
SPECIFIC ELECTRONICS INDUSTRY (SEMICONDUCTORS, LCD)	PFCs NF_3	Fugitive emissions of PFCs and NF_3

7. Project boundaries

The project boundary defines what is to be included in the calculation of absolute and relative emissions. The EIB methodologies use the concept of “scope” based on definitions from the WRI/WBCSD GHG Protocol Corporate Accounting and Reporting Standard when defining the project boundaries.

Scope 1: Direct GHG emissions. Direct GHG emissions are physically emitted from sources that are operated by the project. For example, emissions produced by the combustion of fossil fuels, by industrial processes and by fugitive emissions, such as refrigerants or methane leakage.

Scope 2: Indirect GHG emissions. Scope 2 accounts for indirect GHG emissions associated with energy (electricity, heating, cooling and steam) consumed but not produced by the project. These are included because the project has direct control over energy consumption, for example, by improving it through energy-efficiency measures or by switching to consuming electricity from renewable sources.

Scope 3: Other indirect GHG emissions. Scope 3 emissions are all other indirect emissions that can be considered consequences of project activities (e.g. emissions from the production or extraction of raw materials or feedstock and vehicle emissions from the use of road infrastructure, including emissions from the electricity consumption of trains and electric vehicles).

From the results of the pilot exercise and through working with other IFIs to harmonise approaches to carbon footprinting, it was decided that scope 1 and 2 emissions should be included in the carbon footprint. For the majority of projects financed by the Bank, these are the most significant emissions associated with projects. However, for certain sectors in which scope 3 emissions associated with the projects are significant and can be estimated (e.g. transportation or biofuel production and bioenergy projects, as required for climate action eligibility), scope 3 emissions may be included.

The EIB is currently assessing whether to include the upstream emissions from energy sources in its carbon footprint calculations. This would include the upstream emissions from fossil fuels, electricity generation and biomass. In line with international practice and common practice in the European Union, CO_2 released from the combustion of biomass is accounted for as 0 (zero).[3] Emissions related to off-field logistics and further processing of biomass into chips or pellets shall be accounted for following the provisions of the Renewable Energy Directive (RED) II Directive 2018/2001/EU. In the case of biofuels from agricultural biomass, a full life cycle analysis was already planned under previous versions of the carbon footprint methodologies and taken into account following the methodologies established in the RED.

Setting boundaries for absolute and relative emissions calculations

For some projects, as specified in Table 3, the absolute and relative emissions calculations may have different boundaries.

- Absolute emissions are based on a project boundary that includes all significant scope 1, scope 2 and scope 3 emissions (as applicable) that occur within the project. For example, the boundary for a stretch of motorway would be the length of motorway defined by the finance contract as the project, and the calculation of absolute emissions would cover the GHG emissions of vehicles using that particular stretch of motorway in a typical year.
- Relative emissions are based on a project boundary that adequately covers the “with” and “without” project scenarios. It includes all significant scope 1, scope 2 and scope 3 emissions (as applicable), but it may also require a boundary outside of the physical limits of the project to adequately represent the baseline. For example, without the motorway, traffic would increase on secondary roads outside the physical limits of the project. The relative emissions calculation will use a boundary that covers the entire region affected by the project.

In principle, the absolute and relative emissions footprints are not always directly comparable and should not be added to or subtracted from one another.

[3] GHG emissions and removals due to and related to the management of forest resources and agricultural land are accounted under LULUCF Regulation 2018/841 EU and shall not be taken into account for energy combustion purposes. It is scientifically demonstrated that wood removals as part of sustainable forest management practices (such as tending, thinning, and final cuts followed by forest regeneration) increase carbon sequestration at a general forest inventory level in comparison to unmanaged or poorly managed forests. Following IPPC and EU conventions, the accounting of GHG balances at forest level has to be done according to LULUCF regulations, and the carbon footprint of forest biomass for energy purposes is considered as 0 (zero) as long as this forest biomass comes from sustainably managed forests (Regulation (EU) 2018/841, Directive 2018/2001, Regulation (EU) No 601/2012 (3), and Regulation (EU) No 525/2013).

Table 3: Carbon footprinting of projects: boundary clarifications

PROJECT TYPE	FOOTPRINT BOUNDARY CLARIFICATION
ALL PROJECTS (OTHER THAN THOSE EXCEPTIONS SPECIFIED BELOW)	INCLUSION: Scope 1 and 2 emissions for a typical year of operation. EXCLUSION: Scope 1 and 2 emissions associated with the commissioning, construction and decommissioning of the project. EXCLUSION: Scope 3 emissions. INCLUSION: Scope 3 emissions from 100% dedicated sources upstream or downstream that would not otherwise exist, and a number of specific cases below. An example of the first case would be a power plant that exists solely to supply the project (upstream) or a waste disposal site for the exclusive use of the project (downstream) that would not have otherwise existed.
TRANSPORT MOBILE ASSETS AND INFRASTRUCTURE	INCLUSION: Scope 3 emissions from vehicles travelling on the financed physical infrastructure links or fleets departing from or arriving at a transport node are included in the absolute and the relative emissions calculations. GHG-relative emissions are calculated based on the displacement of passengers from one type of transport to another (modal shift effects), shifts in travel patterns (one road to another or from one time of day to another) and the induced increase in passengers and freight traffic. If the project includes the replacement of rolling stock, the savings in emissions from this intervention should also be taken into account.
ENERGY NETWORK PROJECTS	INCLUSION: Scope 3 emissions from outside the boundary defined by the physical limits of the project are included in the relative emissions calculation where they are considered significant. For example, a district heating network project typically has a boundary that includes the losses of the heat network and any sources of heat generation under the control of the operator. If the project results in fuel switching (individual heating to district heating) or results in a change in the operational regime of a heat plant outside the control of the project operator, significant GHG emissions from these sources are included.
INDUSTRIAL PRODUCTION FACILITIES	INCLUSION: Scope 3 emissions from outside the boundary defined by the physical limits of the project are included in the relative emissions calculation where they are considered significant. For example, the installation of a combined heat and power plant that provides waste heat to a residential area can lead to large GHG savings outside of the project boundary. If an industrial project leads to large energy or GHG emissions outside the direct project, these should be included. EXCLUSION: Scope 3 emissions upstream and downstream of the industrial production are generally not considered (see exception above under “All Projects” covering 100% dedicated upstream and downstream sources). For example, the use of steel to make wind turbines or glass to double glaze windows would not be considered part of the absolute or relative emissions calculation.

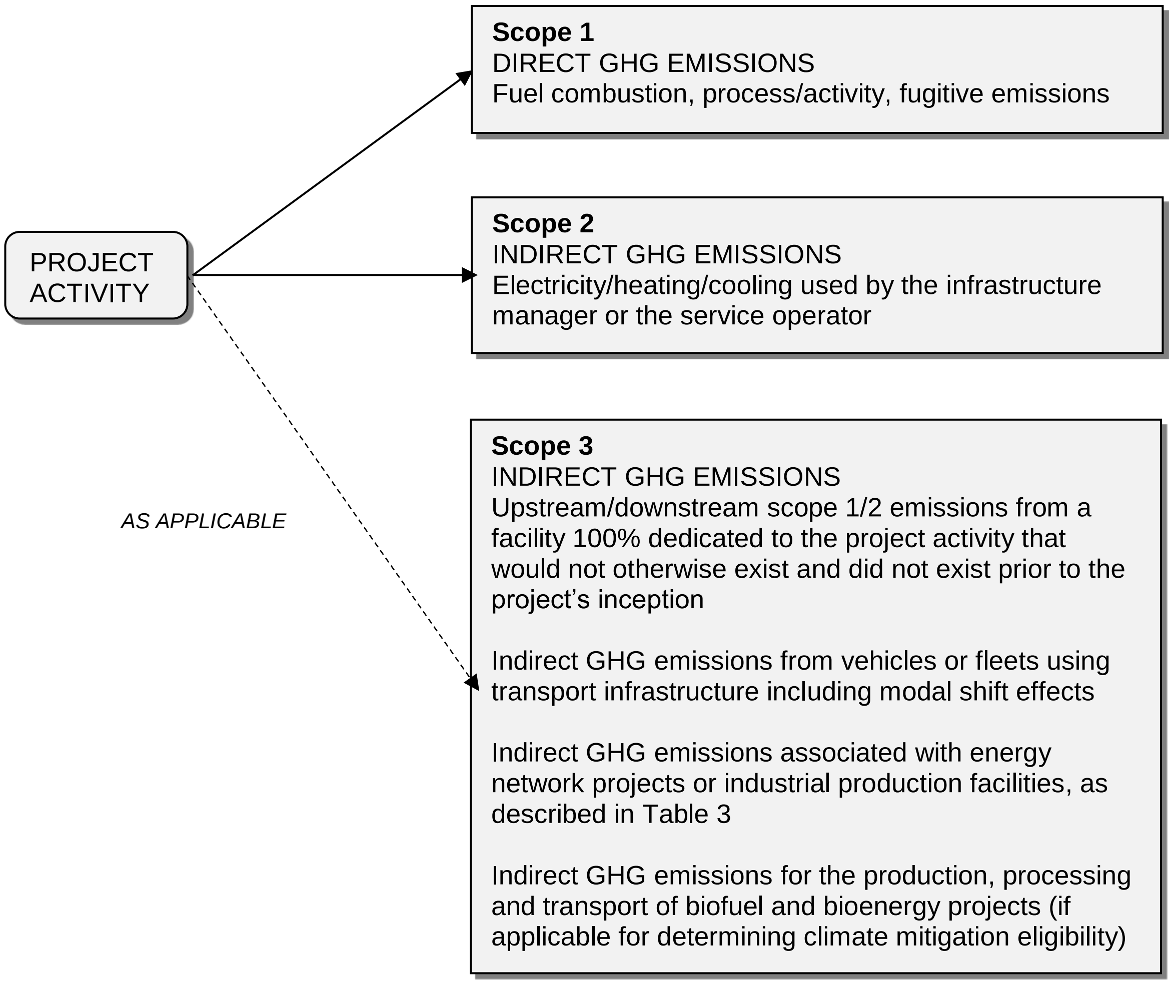
PROJECT TYPE	FOOTPRINT BOUNDARY CLARIFICATION
ALL REHABILITATION/REFURBISHMENT PROJECTS	CLARIFICATION: The boundary for absolute emissions calculations for projects that rehabilitate or refurbish existing facilities corresponds to the boundary of the rehabilitation or refurbishment project and not the GHG emissions for the whole facility. If, however, the GHG emissions of the facility are significantly modified because of the project, the relative emissions calculation shall use a boundary that includes the entire facility. Example 1: The EIB invests in a project to rehabilitate a boiler house in a manufacturing facility. The EIB reports the scope 1 and 2 emissions of the boiler house for the absolute and relative emissions. If the GHG emissions of the rest of the refinery are not affected by the project, the EIB does not report the GHG emissions for the whole refinery. Example 2: The EIB invests in a project to replace 5% of an electricity network. The EIB calculates the emissions associated with the project (losses for 5% of the network). The EIB does not report losses for the whole network.

Carbon leakage. Carbon leakage is not considered in carbon footprint calculations. Leakage normally occurs as a result of one country's climate policies leading to a shift in the emissions sources to another country, but may also occur as the result of an EIB-financed project, for example, when an old technology is replaced and sold on to be used elsewhere (see "Inclusion" under "Industrial Production Facilities" in Table 3).

Rebound effects. Rebound effects in energy-efficiency investments occur when additional energy is consumed because energy efficiency measures make the use of equipment cheaper. This can occur in households (e.g. not switching off energy-saving lights because they consume such little energy) or in industry. These potential effects are not included in the methodology.

Emissions from purchased renewable electricity. For a project's purchased renewable electricity (e.g. guarantee of origin-labelled green electricity), the emissions need to be calculated using the electricity emission factor for that country, not using an emission factor of zero unless there is a dedicated renewable electricity plant or dedicated renewable electricity infrastructure that provides electricity directly to the project.

Figure 1: Project scope — all projects



8. Metrics

8.1 Emission factors

The EIB carbon footprint methodology provides a series of emission factors from which GHG emissions can be calculated. These were derived from internationally recognised sources (e.g. WRI/WBCSD's GHG Protocol Corporate Accounting and Reporting Standard and IPCC Guidelines for National GHG Inventories). These default factors can be used where no other relevant factor is available or where factors that have been provided — by the promoter, for example — appear to be unsubstantiated. Where possible, it is preferable to use project-specific factors in place of the defaults given here, provided that the source of the factors used is consistent with the guiding principles described in Section 4 of the methodologies.

8.2 Absolute emissions (Ab)

A project's absolute emissions (gross emissions, or Ab) will be quantified and included in the footprint if the emissions are greater than positive or negative 20 000 tonnes CO_2e/year (as defined in Section 5). Absolute emissions concern a project's emissions during a typical year of operation (that is, not including its commissioning or unplanned shutdowns). The appraisal team calculates and reports the project's absolute emissions even if the EIB is only contributing part of the total financing.

The absolute emissions should be calculated based on project-specific data. Where project-specific data are not available, it is good practice to use default factors based on sector-specific activity data and the application of documented emission factors. A compilation of default methodologies by sector is attached as Annex 1 to this note for guidance. Emissions will be estimated by multiplying activity data, such as the volume of fuel used or product produced, by a project-specific or an industry default emission factor.

The default methodologies are separated into combustion emissions and those emissions arising from processes other than combustion, normally the result of a chemical reaction during a production process or because of a processing stream. Emissions may also be fugitive, where a leak or vent of a GHG occurs from some part of the project installation, such as a valve or transformer.

A combination of methodologies can be used where appropriate. For example, a project which:

- has on-site energy generation through fuel combustion (e.g. generators, boilers or kilns);
- uses purchased electricity from the national grid; and
- has an associated process-type emission (e.g. cement production)

may use a combination of Annex 1 methodologies to calculate the project's absolute emissions, as follows:

1A Stationary fossil fuel combustion + 1E Purchased electricity + 6 Cement (clinker) production

8.3 Baseline emissions (Be)

Measuring baseline emissions (Be) is a useful complement to absolute emissions. It provides a credible alternative scenario "without" the project, against which the "with" project scenario[4] can be compared, giving an indication of how — measured in GHG metrics — the proposed project performs. However, the "without" project scenario, or baseline, is clearly theoretical and hence incorporates an additional level of uncertainty beyond that involved in estimating absolute emissions.

The project baseline scenario (or "without" project scenario) is defined as the expected alternative means to meet the output supplied by the proposed project.[5]

The baseline scenario must therefore propose the likely alternative to the proposed project which (i) in technical terms can meet the required output; and (ii) is credible in terms of economic and regulatory requirements.[6]

The first step is to propose a baseline scenario that meets demand in technical terms. Three examples are detailed below:

- Example 1: A gas-fired combined heat and power plant (CHP). Without the new plant, the existing power from the grid (the combined margin for firm electricity generation) would have continued to meet demand. The heat co-generated from the CHP would have been provided by a natural gas-fired industrial boiler.
- Example 2: Modernising a cement plant. Without the project, alternative regional plants both existing and newly built or modernised would have met demand.
- Example 3: Rehabilitation of a double-track railway line. New demand is assumed to come from two sources: (i) diverted from existing modes, namely the existing rail service and its main competitors — private cars and buses; and (ii) induced rail trips.

In a second step, it is necessary to check that the proposed scenario is credible. The baseline scenario should meet three conditions:

- The socioeconomic test: In general terms, the baseline scenario should show an economic rate of return above the social economic discount rate.[7] In the specific case that external costs are internalised through public policy (carbon tax, emissions trading scheme, etc.) the financial rate of return of the baseline scenario should not differ significantly from the economic rate of return.
- The legal requirement test: The baseline alternative should comply with binding legal requirements (whether technology, safety or performance standards, including portfolio standards, such as 10% biofuels in the fuel mix requirement).
- The life-expired asset test: The baseline alternative could not assume to continue using existing assets beyond their economic life (based on regular operations and maintenance), at least not without an appropriate deterioration in the quality of service.

[4] In this case, the "with" project scenario is the expected emissions from the project.

[5] In general, the baseline scenario is based on a combination of best-available technology and least-cost principles. In some circumstances, one could also assess alternative scenarios in which prices or regulatory requirements are used to determine options or constrain demand to existing supply. This is relevant where current pricing is clearly inefficient or when regulatory requirements impose specific conditions on all installations.

[6] A baseline that is consistent with the best economic alternative is not necessarily identical to it. The best economic alternative is defined as the most competitive and viable alternative investment to which the project is compared, whereas the baseline for the carbon footprint is the most likely outcome in the absence of the project (e.g. meeting demand through a combination of existing and new infrastructure). The baseline is expected to include the best economic alternative as a component of the emissions calculation.

[7] Note that economic rates of return are not always calculated, for example, in cases of rail/urban asset renewal.

This baseline definition differs in general from an evaluation of emissions “before and after” the investment.

- By definition, emissions prior to developing on a greenfield site are zero. Hence, applying a simple ‘’before and after’’ approach gives rise to a zero baseline. By contrast, the baseline scenario defined above (without a project scenario) places no weight on whether a development is greenfield, brownfield or a partial replacement — the key issue is how the projected demand could otherwise have been met, which is not addressed in the “before and after” scenario.
- If the project is designed to replace a life-expired asset, a ‘’before and after’’ approach would use previous emissions as the baseline. However, this approach would lack credibility in many cases if, for example, the existing asset were life-expired and could not have continued over the course of the asset life of the proposed project.

8.4 Relative emissions (Re)

Relevant emissions (Re) concern a project’s emissions from a typical year of operation (that is, not including its commissioning or unplanned shutdowns). The appraisal team calculates and reports the project’s relative emissions even if the EIB is only contributing part of the total financing. Relative emissions are defined simply as:

Relative Emissions = “With” Project Emissions (Wp) — “Without” Project Emissions, or Baseline Emissions (Be)

(Re = Wp — Be)

The “with” project emissions must have the same boundary as the “without” project emissions in terms of scope but can differ from the boundary used for absolute emissions because the boundary is sometimes extended for relative emissions, such as in the case of networks (see boundary conditions in Section 7 of the methodology above).

Relative emissions may be positive or negative. Where negative, the project is expected to result in savings in GHG emissions relative to the baseline and vice versa (subject to the general caveats surrounding the carbon footprint methodologies). Expressing a project’s relative carbon footprint is one way of evaluating the impact of a project in emissions terms since it provides a context to the absolute emissions of the project (whether the project reduces or increases GHG emissions overall). This can then be used as an indicator, along with others, of the project’s environmental performance.

The examples below present the approach the EIB typically adopts for carbon footprinting in three sectors: energy, industry and transport. All emissions are calculated for a typical year of operation during the economic lifespan of the project.

Example 1: A gas-fired combined heat and power plant (CHP) in Germany

Absolute emissions

The CHP plant is expected to co-generate approximately 800 GWh of electricity per annum and 900 GWh of useful heat. On average, it consumes 2 000 GWh of natural gas per year. The CHP plant’s absolute CO_2 emissions are estimated on the basis of the default emission factor for natural gas: 56 200 kg CO_2e/TJ, or 0.202 kg CO_2e/kWh (including the correction factor for unoxidised carbon). Therefore, the absolute emissions are:

Ab = (2 000 * 0.202 * 1 000 000) / 1 000 = **404 000 tonnes CO_2e/year**

Baseline emissions

In Germany, the combined margin for firm electricity generation would be 0.307 kg CO_2/kWh. This is the carbon intensity of electricity substituted by the project's power output.

In addition, the CHP plant's co-generated useful heat substitutes heat supply from other sources. In this case, the substitution of hot water from a natural gas-fired industrial boiler is assumed. The boiler's direct CO_2 emissions are estimated by multiplying annual heat production (900 GWh/year) by the specific emission factor of such boilers (0.216 kg CO_2e/kWh). Therefore:

Be = (800 * 0.313 * 1 000 000) / 1 000 + (900 * 0.216 * 1 000 000) / 1 000 = **444 800 tonnes CO_2e/year**

Relative emissions

In this example, in the "with" project, emissions are equivalent to the calculation of absolute emissions. Therefore:

Re = 404 000 – 444 800 = **– 40 800 tonnes CO_2e/year**

Overall, when compared to the baseline scenario, the project is expected to result in an emissions reduction of 40 800 tonnes of CO_2 per annum due to the displacement of both less-efficient firm generation that is currently produced on the German grid and the supply of heat from an industrial natural gas boiler.

Example 2: Modernisation of a cement plant in Italy

Absolute emissions

The cement plant substitutes in part clinker with slag from a nearby steel plant. The plant produces 1 200 000 tonnes of cement using 800 000 tonnes of clinker. The conversion factor for clinker production is 0.83 t CO_2e/t. The plant also purchases electricity at 40 kWh/t of cement produced converted to CO_2e using the Italian emission factor for electricity consumption for heavy industry (HV grid) of 0.228 kg CO_2/kWh.

Ab = (800 000 * 0.83) + (1 200 000 * 40 * 0.2228 / 1 000) = **674 953 tonnes CO_2e/year**

Baseline emissions

Cement markets are predominantly regional, so the baseline reflects how cement production would be met using local plants. Assuming one tonne of cement produced locally requires 0.889 tonnes of clinker, in order to produce the same amount of cement, 1 066 800 tonnes of clinker would be required. Purchased electricity is 50 kWh/t cement-produced.

Be = (1 066 800 * 0.83) + (1 200 000 * 50 * 0.228 * 1000) = **899 135 tonnes CO_2e/year**

Relative emissions

Re = 674 953 – 899 135 = **–224 182 tonnes CO_2e/year**

Overall, the project, compared to the baseline scenario, is expected to result in a reduction in emissions of 224 182 tonnes CO_2e/year. This is due to the partial replacement of high CO_2-emitting clinker with slag from a neighbouring steel plant.

Example 3: Rehabilitation of a railway line in Poland

For rail infrastructure projects, when a cost–benefit analysis (CBA) is prepared with the Bank's proprietary Excel-based model, RAILMOD, the carbon footprint is calculated using this model.

Absolute emissions

The project concerns the modernisation of an existing double-track electrified railway line in Poland of about 140 km. The line usage at opening is forecast to be about 60 electric-powered trains per day. With 365 days in a year, this means 21 900 trains per year. The absolute emissions are calculated by multiplying the assumed power consumption; in this case, 10.5 kWh/train-km, by the Polish emission factor for electricity consumption for railways (HV grid) of 543 g/kWh, the total train-km per year and the assumed growth in train-km over time, including for demand induction as a result of the project (EIB services' assumption based on national plans).

The absolute emissions based on these inputs is estimated to be 17 471 tonnes of CO_2e per average operating year: 140 km * 21 900 trains/year * 10.5 kWh/train-km * 543 g/kWh / 1 000 000.[8]

Baseline emissions

Usage of the line without modernisation is about 56 electric powered trains per day. Using the assumptions above for emissions calculation (10.5 kWh/train-km and an emission factor for electricity of 543 gCO_2/kWh), the emissions for the existing 140 km of double-track railway are estimated to be 16 307 tonnes per average operating year.

Opening-year passenger demand is assumed to come from two sources: (i) diverted from existing modes, namely the existing rail service as well as the main competitors (private cars and buses); and (ii) induced rail trips. In this example, the vast majority of opening-year passenger traffic is forecast to be diverted from existing rail. A portion will also be diverted from buses (4%) and cars (4%), and a portion is induced (about 10% on average). Passenger demand diverted from other modes is captured in the baseline emissions (in the baseline, a portion of traffic is assumed to be travelling by car/bus at a higher emission rate per passenger/km).

As per RAILMOD, the baseline forecast comes to 22 800 tonnes per average operating year.

Relative emissions

In this example, the "with" project emissions are equivalent to the calculated absolute emissions. Therefore:

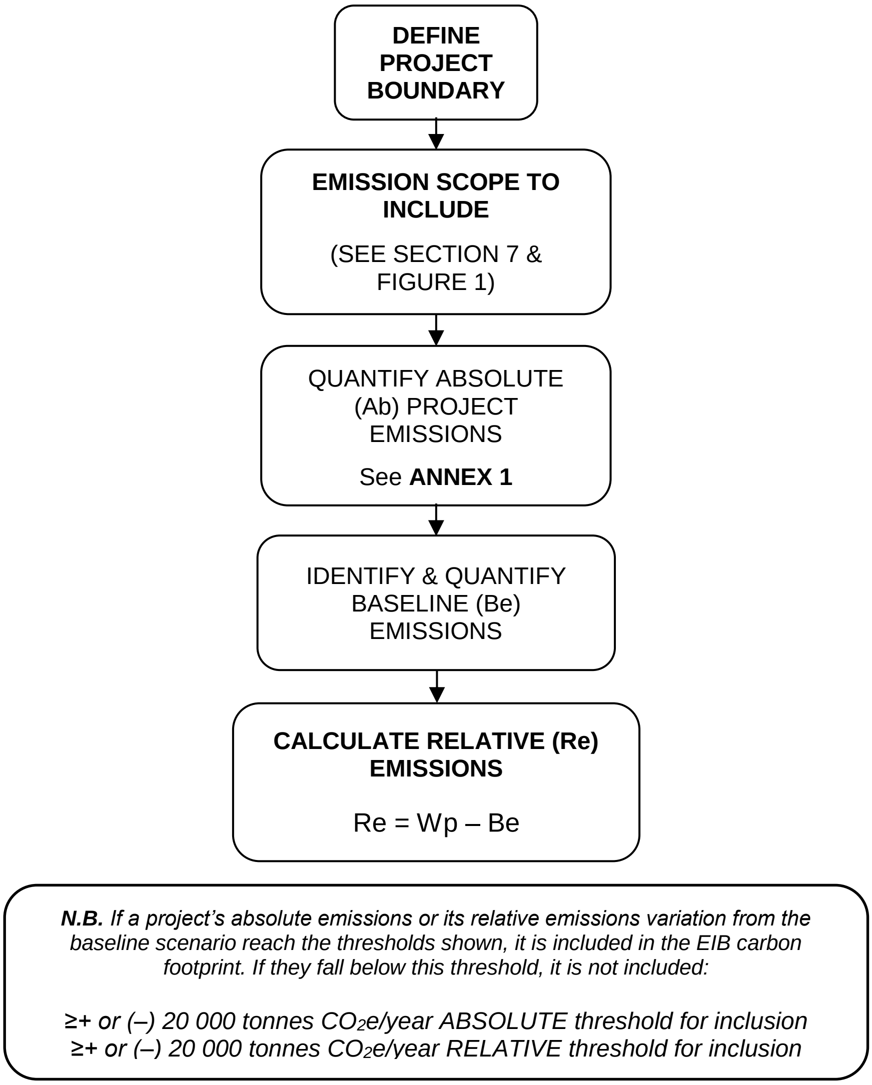
Re = 17 471 – 22 800 = **– 5 329 tonnes CO_2e/year**

[8] Small difference due to rounding error emission factor.

9. Quantification process and methodologies

Figure 2 illustrates the overall series of activities to quantify the EIB's carbon footprint for investment projects and the associated relative emissions compared to the baseline.

Figure 2: Project carbon footprint calculation flow



9.1 Assessment of intermediated projects

Quantifying the carbon footprint for multi-investment (intermediated) projects (e.g. multi-beneficiary intermediated loans, framework loans, green bond purchasing programmes, global loans, equity and debt funds) poses challenges. Information on the large number of sub-projects financed under these operations is highly limited, which does not enable a reasonable assessment of GHG emissions from the sub-projects, especially smaller ones and those targeting small and medium-sized enterprises. Intermediated lending through these types of vehicles is not currently included in the carbon footprint, except for allocations of framework loans[9] that are subject to individual appraisal and submission to the Board. These should be treated as investment loans and included in the footprint if emissions cross the thresholds in the year the allocation is approved by the Bank.

[9] The threshold for allocations of a framework loan requiring an individual appraisal is normally those exceeding €50 million in project investment costs.

ANNEX 1: DEFAULT EMISSIONS CALCULATION METHODOLOGIES

<table>
<tr><th>Method #</th><th>Sector and GHG</th><th>Calculation Input Data Requirements</th><th>Calculation Method</th></tr>
<tr><td>1A</td><td>Stationary fossil fuel combustion
CO_2e</td><td>(i) Annual fuel use in energy units (e.g. TJ), volume or mass units
(ii) Default emission factor (see Table A1.1)</td><td>CO_2e (t) = fuel energy use * emission factor</td></tr>
<tr><td>1B</td><td>Stationary fossil fuel combustion
N_2O</td><td>(i) Annual fuel energy input (derive from data above)
(ii) Default emission factor (see Table A1.1)</td><td>N_2O (t) = fuel energy input * emission factor</td></tr>
<tr><td>1C</td><td>Stationary biomass fuel combustion[10]
CH_4 and N_2O</td><td>(i) Fuel energy input (derive from data above)
(ii) Default emission factors (CH_4 and N_2O expressed as CO_2e):
<table>
<tr><th></th><th>t CO_2e/TJ</th></tr>
<tr><td>Energy/Manufacturing</td><td></td></tr>
<tr><td>- Gaseous</td><td>0.0545</td></tr>
<tr><td>- Liquid</td><td>0.243</td></tr>
<tr><td>- Solid</td><td>1.9</td></tr>
<tr><td>- Municipal waste</td><td>1.9</td></tr>
<tr><td>- Unknown</td><td>1.37</td></tr>
<tr><td>Commercial/Residential</td><td></td></tr>
<tr><td>- Gaseous</td><td>9.46</td></tr>
<tr><td>- Liquid</td><td>0.439</td></tr>
<tr><td>- Solid</td><td>0.1665</td></tr>
<tr><td>- Municipal waste</td><td>9.46</td></tr>
<tr><td>- Unknown</td><td>3.33</td></tr>
</table>
(iii) In line with international practice and common practice in the European Union, CO_2 releases from the combustion of biomass is accounted as 0 (see footnote 3 earlier in the text).
(iv) Emissions associated with the production of agricultural biomass fuel and the processing of agricultural and forest biomass include, where significant:
Fertilisers for purpose-grown energy crops (N_2O); fuel oil consumed to run machinery at the farm level; chipping; drying, torrefaction and pelletising solid biomass (CO_2); long-distance transportation (CO_2); factors on a case-by-case basis</td><td>CH_4 (t) = fuel energy input * emission factor
N_2O (t) = fuel energy input * emission factor

Conversion factors to convert to CO_2e (see Table A1.9)</td></tr>
<tr><td>1D</td><td>Co-generation combined heat and power (CHP)
CO_2e</td><td>Direct emissions from fuel combustion to follow methodologies 1A and 1C, as applicable, above.</td><td></td></tr>
<tr><td>1E</td><td>Purchased electricity
CO_2</td><td>(i) Energy purchased for use in project activities
(ii) Country-specific emission factors (see Table A1.3) for electricity consumption or in special cases, such as electricity for pumped storage, the appropriate combination of marginal plants</td><td>CO_2 (t) = energy use * country-specific emission factors for electricity consumption</td></tr>
<tr><td>1F</td><td>Renewable energy</td><td>(i) Zero or minor absolute emissions except for hydropower with large reservoir storage</td><td>CO_2 (t) = energy generated * country-</td></tr>
</table>

[10] Note that emissions from the combustion of biomass in power generation, industry, waste treatment or transport fuels, for example, are considered zero, as explained previously (see footnote 4 and associated explanation).

Method #	Sector and GHG	Calculation Input Data Requirements	Calculation Method
	CO_2e	capacity (see hydro reservoir emissions in Table A1.8) (ii) Renewable energy is assumed to displace (at least in part) fossil fuels (see electricity-generation baseline assumptions in Annex 2).	specific emission factor for electricity combined margin
1G	**Stationary combustion of waste-type fuels** **CO_2e**	(i) Annual fuel use (ii) Default emission factor (see Table A1.1) (iii) Zero or minor absolute emissions for organic portion of waste fuels	CO_2 (t) = fuel use * fuel emission factor
2	**Oil/gas production, processing, storage and transport** **CO_2, CH_4**	All combustion, including flare emissions, may be derived from 1a above. Emissions of N_2O are not considered significant in petroleum refining and gas processing (IPIECA GHG Guidelines, 2003). Compressor emissions are calculated from fuel combustion as above or from purchased energy. **Fugitive emissions** Fugitive emissions are leaks from components such as pipe connections, valves, rotating shafts etc. The calculation of fugitive emissions is insensitive to the number of components, and the benefit to be derived from identifying the precise number of components is negligible. A coarse estimate of component numbers, focusing on large potential sources such as compressors, is recommended. (i) Facility production of transport system flow rates (ii) Emission factors (see Table A1.2) (iii) API Compendium lists a default approach: assume that storage tank working and breathing loss emissions are negligible for CO_2 and CH_4. **Storage tank fugitive emissions** (i) API Compendium lists a default approach: assume that tank working and breathing loss emissions are negligible for CO_2 and CH_4. **Catalytic regeneration** (i) Rated throughput of the unit (ii) Benchmark energy consumption for the unit; and verified feed or product density data as appropriate in kWh fuel (net)/t throughput (iii) Catalytic cracking unit factor (pet coke) = 0.358 kg CO_2/kWh* **Hydrogen generation** (i) Hydrogen feed processed (conservatively based on ethane) (ii) Hydrogen gen. emission factors 2.19 t CO_2/t feed* *EU ETS 2007 **Liquefied natural gas (LNG) production** Liquefaction of natural gas utilises part of the supply of gas to the plant for energy consumption: 7.7 t CO_2/TJ of LNG **LNG vaporisation** There are two common methods of vaporisation. The first is to use heated water baths in a submerged combustion vaporisation process. CO_2 emissions arise from the combustion of fuel gas.	Fugitive emissions and venting t CO_2/year = Volume or mass of ref. gas * emission factor ref. gas Fugitive CH_4 = emission factor * production Catalytic regeneration kg CO_2 = throughput kWh x 0.358 Hydrogen gen. CO_2 (t) = Hydrogen feed x 2.19 Note: Detailed emission factors are known to show wide variation. SCV t CO_2 = tonnes LNG design capacity * load % * 0.393 1 t LNG = 0.0545 TJ 1 t LNG = 15.14 MWh

Method #	Sector and GHG	Calculation Input Data Requirements	Calculation Method
		(i) LNG design throughput (ii) Load factor (iii) Apply 00.98 t CO_2/TJ of LNG. The second process is an open-rack seawater system which involves no combustion but may use significant amounts of imported electricity to power water pumps. Emissions from the storage of LNG are not considered material. *(LNG emission factor for liquefaction is based on emissions for LNG liquefaction terminals in Egypt. The value for regasification is based on a regasification plant in Greece.)* **LNG transportation** Transport of natural gas utilises LNG boil-off for fuel, on-board electricity generation, refrigeration and gas compression. The energy intensity of LNG shipping is: 1.13 t CO_2/TJ for a shipping transport duration of 100 hours.	
3	**Coal mining** **CH_4**	(i) Annual mass of coal mined (ii) Default emission rates: • underground coal: 10–25 m^3 CH_4/t coal • surface-mined coal: 0.3–2 m^3 CH_4/t coal • underground, post-mining: 0.9–4 m^3 CH_4/t coal • surface-mined, post-mining: 0–0.2 m^3 CH_4/t coal	CH_4 (t) = coal mined (t) * (emission per tonne mined + emission per tonne post-mining) * 0.00067 Conversion factors to convert to CO_2e (see Table A1.9)
4	**Electricity, gas and heat transmission and distribution** **CO_2 and SF_6**	Scope 1 direct emissions and scope 2 electricity consumption and fugitive emissions from equipment and the network, over an average year. (i) Distribution losses for the part of the network (energy) affecting the project (ii) Electricity consumption based on the country electricity emission factor (Table A1.3) (iii) Total quantity of SF_6 in switchgear and circuit breakers (iv) Switchgear and circuit breakers: SF6 leakage rate: total life cycle: 0.4%, only operation phase: 0.13% (v) Fugitive emissions (see methodology 2) If GHG emissions are only quantifiable for the whole network, then a pro-rata proportion must be calculated for the extension/rehabilitation only. All network losses associated with incremental supply are attributed to network extensions (see Annex 2). If the secondary effects of the project on GHG emissions are significant and there is no risk of double counting, these effects are included as emissions outside the project boundary for the assessment of baseline and relative emissions. Examples include the impact of redispatch of existing generation connected to an electricity network, de-bottlenecking existing RES generation or heat fuel switching of customers connected to gas or district heating networks. Due to the risk of double counting, the impact of future new infrastructure connected to the network (e.g. new power or heat plants, industrial facilities or buildings) should not be included.	GHG emissions for electricity transmission and distribution losses = energy loss * country-specific emission factor for electricity consumption. Assume high-voltage losses of 2%, medium-voltage losses of 4% and low-voltage losses of 7% (non-cumulative). For electricity, the baseline without the project is to meet market demand, assuming increased network losses. In such cases, baseline losses are assumed to be equal to: current % of network losses x (1 + % demand growth) SF_6 (CO_2 t/y) = SF_6 project inventory(t) * SF_6 leakage rate * SF_6/CO_2 emission factor Conversion factors to convert to CO_2e (see Table A1.9)

Method #	Sector and GHG	Calculation Input Data Requirements	Calculation Method
5	**Flue gas desulphurisation (limestone-based)** **CO_2**	(i) Annual usage of limestone (t) (ii) Calcium carbonate content (% wt) (iii) Magnesium carbonate content (% wt)	CO_2 (t) = annual usage (t) x [(% $CaCO_3$ * 12/100) + (% $MgCO_3$ * 12/84)] * 3.664
6	**Industrial processes** **All GHGs**	The main emissions sources from industrial processes are those which chemically or physically transform materials. Industrial processes include: • Metal industry processes, such as aluminium, iron, steel, lead, copper and zinc production. • Chemical industry processes, such as the production of nitric acid, ammonia and adipic acid • Mineral industry processes, such as cement, lime, glass and soda ash production • Other industry processes, such as pulp and paper production The footprint calculation will include: (i) Emissions from 1A stationary combustion of fossil fuels (ii) Emissions from 1E purchased electricity (iii) Plant-specific process emissions Plant-specific process emissions are those produced for industrial activities not related to energy.	If plant-level information is not available, use 2006 IPCC Guidelines for National Greenhouse Gas Inventories Volume 3 for default factors available on PJ's intranet page.
7	**Wastewater and sludge treatment** **CO_2, CH_4, N_2O**	Significant CH_4 emissions from wastewater treatment only arise from the anaerobic part of the process. Sludge disposal (e.g. landfill, use in agriculture, incineration) may also be responsible for CH_4 emissions. Collection of wastewater in underground sewers is not a significant source of CH_4 emissions, and these emissions are included in the emission factors covered by the IPPC methodology. For regular cases, the emissions can be calculated according to the emission factors set out in the table in Annex 6. This table includes the most utilised wastewater treatment technologies and sludge disposal routes and was calculated using the EIB's own tool for calculating carbon footprints in the water sector. These values include the emissions in CO_2e (t/y) produced in the wastewater treatment process (CH_4, N_2O), the indirect emissions due to electricity consumption and the emissions in CO_2e (t/y) produced by the final disposal of sludge (CH_4). They have been calculated by the EIB using its own tool based on the 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, which was adopted and accepted during the 49th Session of the IPCC in May 2019. For more complex cases, EIB personnel can calculate the emissions using the same tool. This tool can also be used for other water-related projects, such as drinking water treatment and supply.	See table in Annex 6.
8	**Road transport** **CO_2**	A proprietary model, ERIAM, is used. This takes project input data in the form of traffic data and costs data and calculates the emissions without the project and emissions with the project for third-party use of the project infrastructure in the form of existing and induced traffic indirect emissions. Induced traffic is determined by the analyst on a case-by-case basis according to the	ERIAM.xls

Method #	Sector and GHG	Calculation Input Data Requirements	Calculation Method
		project's circumstances, usually by applying an appropriate elasticity to the percentage change in expected time savings in the opening year. The model has an assumed set of relationships relating to speed and fuel use, speed and traffic flow and fuel use and GHG emissions. The sector expert can select the relative ratio of diesel and gasoline vehicles in use and the type of vehicles considered light-vehicle diesel and gasoline- and heavy-goods vehicle diesel. Emission factors for fuel types can be entered by the user into the model. Emission factors may be found in Table A1.7 but can also be included based on specific promoter information or sector expertise. Emissions from the project construction phase are not included.	
9	**Rail transport** **CO_2**	A proprietary model, RAILMOD, is used. This takes project input data on rail line lengths and uses and calculates the avoided emissions, absolute emissions and baseline emissions. Alternative modes that are considered are rail, high-speed rail, car (truck for freight), bus and plane. Modal shift is accounted for. Emission factors for fuel types can be entered by the user into the model. Emission factors may be found in Table A1.7 but can also be included based on specific promoter information or sector expertise. If the project concerns rolling stock replacement, the project boundary is the fleet being replaced and the operation to which it is dedicated. Absolute emissions are those related to the operation carried out by these vehicles: the total yearly production in train-km for the replaced fleet is calculated. Based on this, on the average consumption (per car-km or train-km) of fossil fuel or of electric energy, and on the CO_2 emission factor (grams of CO_2 per litre of fossil fuel or per kWh), total fleet emissions per year are calculated (scope 1 or 2 emissions). For baseline emissions, either the replaced fleet is taken as a conservative assumption (if the old fleet can still be legally operated) or, if sufficient information is available, any modal shift and induced traffic is calculated. Emissions from the project construction phase are not included.	RAILMOD.xls
10	**Urban public transport** **CO_2**	A proprietary model, URBMOD, is used to calculate emissions. This takes project input data from the promoter's traffic model and calculates absolute, baseline and relative emissions. Absolute emissions are calculated as those stemming from the project's operation. The calculation of baseline emissions is based on the change in emissions for all other modes stemming from the reduction of mileage of competing modes resulting from the shift in demand to the project. Relative emissions therefore represent the net change across the network as a result of the project. Reported emissions are the average over the entire project's economic life. URBMOD appraises different urban public transport modes including electricity-based systems, such as suburban railways, metro and	UTD/URBMOB proprietary model (URBMOD) which uses distance travelled and an emission factor for the mode of transport.

Method #	Sector and GHG	Calculation Input Data Requirements	Calculation Method
		tramway lines, light rail systems and trolley/electric buses, as well as standard buses. Default emission factors in URBMOD are based on COPERT/TREMOVE values for the urban cycle and are country-specific. The user can overwrite default values and enter specific emission factors into the model using values found in Table A1.7 or based on specific promoter information or sector expertise. For electricity-based systems, the user enters a project's specific consumption rate in the model (kWh/km), which is then converted into GHG emissions (gCO_2/kWh) through average electricity emission factors reported in Table A1.3. URBMOD is typically used for new infrastructure with significant impacts on service supply and demand. It is not used for asset renewal with marginal impact on supply and demand, for which a demand estimate based on a traffic model is normally not available. For the type of operations where modal shift is limited, absolute emissions are calculated as those stemming from the project's operation, while baseline emissions are calculated in relation to a credible alternative consistent with the guiding principles set out in this methodology. Emissions from the project construction phase are not included.	
11	**Other transport** **CO_2e**	**<u>Vessels</u>** If the project is financing a new fleet of vessels, the project boundary is the financed vessels and the expected operations. Absolute emissions of a new fleet/vessel are the average annual emissions of the vessel(s) included in the project. This estimation is based on expected annual fuel use per fuel type of the project vessel(s) (if available, otherwise averages will be used) and standard fuel emission factors. No absolute emissions are calculated for retrofit operations. Relative emissions are calculated as the average per unit emissions savings between the project and the "without project" scenario over the economic life of the project, multiplied by the traffic in the project scenario. In competitive markets, the relative emissions are expected to be limited. **<u>Ports</u>** A detailed methodology for the calculation of the carbon footprint of a port project can be found in ANNEX 5: PORTS AND AIRPORTS CARBON FOOTPRINT CALCULATION METHODOLOGY. **<u>Air</u>** If the project is financing new aircraft, the project boundary is the financed aircraft and the operation to which the aircraft is dedicated. Absolute emissions are those related to the operation of these assets: the total yearly production in km is estimated based on the routes taken and number of trips per annum. Using this figure and the average occupancy of the plane in number of passengers, the emissions can be expressed by multiplying by the efficiency factor of the aircraft expressed in gCO_2/pax*km.	Absolute emissions = project fleet energy consumption per fuel type * emission factors Relative emissions = (average per unit emissions without project – average per unit emissions with project) * project traffic

Method #	Sector and GHG	Calculation Input Data Requirements	Calculation Method
		Airports A detailed methodology for the calculation of the carbon footprint of an airport can be found in ANNEX 5: PORTS AND AIRPORTS CARBON FOOTPRINT CALCULATION METHODOLOGY. **E-mobility, including hybrids, full battery electric and hydrogen fuel cell vehicles, and its charging infrastructure** If the project concerns fleet replacement, the project boundary is the fleet financed and the operation to which it is dedicated. If the project is recharging or refuelling infrastructure, the project boundary is the energy dispensed by the infrastructure to a fleet being served. Absolute emissions are those related to the operation carried out by these fleets: the total yearly production in vehicle-km or vessel-km. Based on the average consumption of electric energy or hydrogen (combined with any other (fossil) fuel consumption in the case of hybrid vehicles), and on the CO_2 emission factor (grams of CO_2 per kWh or per kg of H_2), the annual total fleet direct emissions are calculated (scope 1 or 2 emissions). Average consumption is based on (industry) standards if no other information is available (e.g. WLTP (Worldwide Harmonised Light Vehicle Test Procedure) for cars and vans and VECTO (Vehicle Energy Consumption Calculation Tool) for heavy-duty vehicles).If VECTO data are not (yet) available, a reasonable proxy is assumed. CO_2 emission factors for electricity consumption are based on the electricity emission factor for that country unless justified in line with guidance in paragraph 7. For hydrogen, as "grey" hydrogen is the dominant type of hydrogen, scope 2 emissions will need to be based on this type of hydrogen unless another source can be assumed over the lifetime of the vehicle (9.98 kg CO_2-eq/kg H_2).[11] Baseline emissions are calculated in relation to a conventional fleet (internal combustion engines running on fossil fuels). **For all of the above**: Emissions from the project construction phase are not included.	
12	**Reservoirs** **CO_2, CH_4**	(i) Flooded total surface area (ii) CO_2 diffusive emission factor (Table A1.8) (iii) CH_4 diffusive emission factor (Table A1.8) (iv) CH_4 bubbles emission factor (Table A1.8) The large uncertainties associated with IPCC emission factors should be noted.	CO_2 = 365 * ii * i CH_4 = (365 * iii * i) + (365 * iv*i) Conversion factors to convert to CO_2e. (See Table A1.9.)
13	**Waste treatment facilities**	Absolute process emissions are calculated using default emission factors (IPCC 2006). Baseline scenario for waste treatment facilities in the European Union: basic MBT (mechanical biological treatment) facility with separation of large bulky fractions and subsequent aerobic stabilisation of biodegradable waste fractions, landfill disposal of all residues with insignificant GHG emissions from residue disposal.	Composting: 4 kg CH_4 per tonne of waste 0.24 kg N_2O per tonne of waste Anaerobic digestion: 0.8 kg CH_4 per tonne of waste Waste incineration: 91.7 t CO_2 / TJ fossil

[11] Source for emission factors: https://www.ademe.fr/sites/default/files/assets/documents/panorama_autobus_urbain_2018.pdf

Method #	Sector and GHG	Calculation Input Data Requirements	Calculation Method
		Baseline scenario for waste treatment facilities beyond Europe: an engineered landfill with minimum landfill gas collection and flaring.	municipal solid waste input 143.0 t CO_2 / TJ industrial waste input or 91.7 t CO_2 / TJ fossil share of input if characteristics are similar to MSW. 0.03 t CH_4 / TJ fossil municipal solid waste input 0.004 t N_2O / TJ fossil municipal solid waste input Relevant CO_2 default emission factor for auxiliary fuel used
14	**Municipal solid waste landfill** **CH_4**	CH_4 emissions are calculated using the IPCC 1996 Default Methodology Tier 1. This evaluates the total potential yield of methane from the waste deposited, expressed as an average annual emission. The following data are required: (i) Annualised mass of MSW to be deposited, MSWT (t/y) (ii) Methane correction factor (MCF) — reflecting the nature of waste disposal practices and facility type. Recommended values are: a. Managed (anaerobic) (controlled waste placement, fire control, and including some of the following: cover material, mechanical compacting or levelling): MCF = 1 b. Managed (semi-aerobic) (controlled placement and all structures for introducing air to waste layer: permeable cover material, leachate drainage system, regulating pondage and gas ventilation system): MCF = 0.5 c. Unmanaged — deep (> 5 m waste): MCF = 0.8 d. Unmanaged — shallow (< 5 m waste): MCF = 0.4 e. Uncategorised (default): MCF = 0.6 (iii) Degradable organic carbon (DOC) — fraction of MSW that is degradable carbon. Default values are: food waste (0.15), garden (0.2), paper (0.4), wood and straw (0.43), textiles (0.24), disposable nappies (0.24), sewage sludge (0.05), rubber (0.39), bulk MSW (0.18) and industrial waste (0.15). (iv) Fraction of DOC dissimilated (DOCF) — (the fraction that is ultimately degraded and released): default = 0.5 (v) Fraction by volume of CH_4 in landfill gas (vi) Mass of CH_4 recovered per year for energy use or flaring, R (t/y) (vii) Fraction of CH_4 released that is oxidised below surface within the site, OX. Default is OX = 0.1 for well-managed sites, otherwise 0.	CH_4 (t/y) = [MSWT x L0 - R] x [1 - OX] where L0, the methane generation potential in t CH_4 / t MSWT is calculated as: L0 = MCF x DOC x DOCF x F x (16/12) The CO_2 fraction of landfill gas and CO_2 from landfill gas flaring is assumed to be GHG-neutral as part of the biological cycle.
15	**Refrigeration/air conditioning/insulation industry HFCs**	A variety of industrial processes involve refrigeration and air conditioning and thus indirectly employ HFCs. It is recommended that only where the manufacture and use of such equipment is a major aspect of a project should	

Method #	Sector and GHG	Calculation Input Data Requirements	Calculation Method
		an assessment be undertaken. In such cases, the user is referred to the IPCC 1996 Reference Manual for recommended sector-specific calculation methods. See Table A1.9 for the global warming potential of HFCs.	
16	**Semiconductor and LCD manufacturing — construction and operation wafer plants**	Electronics manufacturing processes utilise polyfluorinated compounds (PFCs) for plasma etching, intricate patterns, cleaning reactor chambers and temperature control. The gases include CF_4, C_2F_6, C_3F_8, c-C_4F_8, c-C_4F_8O, C_4F_6, C_5F_8, CHF_3, CH_2F_2, NF_3 and SF_6. In addition, more than 20 different liquid PFCs are marketed, often as mixtures of fully fluorinated compounds to the electronic sector. Evaporative losses contribute to total FC emissions.	Gas into the process chamber, gas out of the process chamber and % of the gas out that is being retained by abatement systems.
17	**New buildings and refurbishment** **CO_2**	(i) Electric energy purchased for use in the buildings (ii) Thermal energy/fuel purchased for use in the buildings (iii) Project-specific heat emission factors (district heating, fossil fuel boilers, building or apartment level) (iv) Country-specific emission factors (See Table A1.3.)	CO_2e (t) = electric energy use * country-specific emission factor for electricity consumption + heat energy use * project-specific heat emission factor
18	**Forestry** **CO_2, N_2O**	A detailed methodology for the calculation of the carbon footprint of a forestry project can be found in ANNEX 3: FORESTRY CARBON FOOTPRINT CALCULATION METHODOLOGY.	
19	**Installation, upgrading and/or expansion of fixed telecommunications network**	1E purchased electricity for the full network (core, backhaul, access, network operation centre, etc.). 1E purchased electricity of the CPEs (if included in the project scope). For new network roll-out, the baseline should refer to state-of-the-art equipment. If the project includes a swap-out of existing equipment, previous technological generation should be used for the baseline to allow for capturing the increase in energy efficiency.	
20	**Installation, upgrading and/or expansion of mobile telecommunications network**	1E purchased electricity Where significant diesel generation capacity is installed for the base stations, then also use 1A stationary combustion. Power consumption of mobile handsets is not to be included. For new network roll-out, the baseline should refer to state-of-the-art equipment. If the project includes a swap-out of existing equipment, previous technological generation should be used for the baseline to allow for capturing the increase in energy efficiency.	
21	**Installation, upgrading and/or expansion of submarine cables, satellite networks and infrastructure or data centres**	1E purchased electricity	

Table A1.1: Default emission factors

TJ (terajoule) factors are from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories. These factors assume no unoxidised carbon. To account for unoxidised carbon, the IPCC suggests multiplying by these default factors: solid = 0.98, liquid = 0.99, and gas = 0.995. Other factors are from the WRI/WBCSD GHG Protocol Corporate Accounting and Reporting Standard.

GASEOUS FOSSIL FUELS

Fuel name	Amount of fuel	Units	kg CO_2	kg CH_4	kg N_2O	kg CO_2e	kg CO_2e incl. unoxidised carbon
Natural gas	1	Cubic metre (m^3)	1.9	0.0	0.0	1.9	1.9
Natural gas	1	TJ	56 100	1.0	0.1	56 155	55 874
Refinery gas	1	metric tonne (t)	2 851	0.0	0.0	2 851	2 837
Refinery gas	1	TJ	57 600	1.0	0.1	57 655	57 367
Liquefied petroleum gases	1	litres (l)	1.6	0.0	0.0	1.6	1.6
Liquefied petroleum gases	1	TJ	63 100	1.0	0.1	63 155	62 839
Blast furnace gas	1	metric tonne (t)	642	0.0	0.0	642	639
Blast furnace gas	1	TJ	260 000	1.0	0.1	260 054	258 754
Coke oven gas	1	metric tonne (t)	1 718	0.0	0.0	1 718	1 709
Coke oven gas	1	TJ	44 400	1.0	0.1	44 454	44 232
Oxygen steel furnace gas	1	metric tonne (t)	1 284	0.0	0.0	1 284	1 278

LIQUID FOSSIL FUELS

Fuel name	Amount of fuel	Units	kg CO_2	kg CH_4	kg N_2O	kg CO_2e	kg CO_2e incl. unoxidised carbon
Gas/diesel oil	1	litres (l)	2.7	0.0	0.0	2.7	2.7
Gas/diesel oil	1	TJ	74 100	3.0	0.6	74 343	73 600
Crude oil	1	litres (l)	2.5	0.0	0.0	2.5	2.5
Crude oil	1	TJ	73 300	3.0	0.6	73 543	72 808
Refinery feedstocks	1	metric tonne (t)	3 152	0.1	0.0	3 155	3 123
Refinery feedstocks	1	TJ	73 300	3.0	0.6	73 543	72 808
Motor gasoline	1	litres (l)	2.3	0.0	0.0	2.3	2.3
Motor gasoline	1	TJ	69 300	3.0	0.6	69 543	68 848
Aviation/jet gasoline	1	litres (l)	2.2	0.0	0.0	2.2	2.2
Aviation/jet gasoline	1	TJ	700 000	3.0	0.6	700 243	693 241
Aviation/jet gasoline	1	metric tonne (t)	3 101	0.1	0.0	3 104	3 073
Jet kerosene	1	TJ	71 500	3.0	0.6	71 743	71 026
Naphtha	1	litres (l)	2.5	0.0	0.0	2.5	2.5
Naphtha	1	TJ	73 300	3.0	0.6	73 543	72 808
Shale oil	1	litres (l)	2.8	0.0	0.0	2.8	2.8
Shale oil	1	TJ	73 300	3.0	0.6	73 543	72 808
Residual fuel oil/HFO	1	litres (l)	2.9	0.0	0.0	2.9	2.9
Residual fuel oil/HFO	1	TJ	77 400	3.0	0.6	77 643	76 867
Other kerosene	1	litres (l)	2.5	0.0	0.0	2.5	2.5
Other kerosene	1	TJ	71 900	3.0	0.6	72 143	71 422

SOLID FOSSIL FUELS

Fuel name	Amount of fuel	Units	kg CO_2	kg CH_4	kg N_2O	kg CO_2e	kg CO_2e incl. unoxidised carbon
Anthracite	1	metric tonne (t)	2 625	0.0	0.0	2 625	2 573
Anthracite	1	TJ	98 300	1.0	1.5	98 726	96 751
Bitumen	1	metric tonne (t)	3 244	0.1	0.0	3 247	3 182
Bitumen	1	TJ	80 700	3.0	0.6	80 943	79 324
Lignite	1	metric tonne (t)	1 202	0.0	0.0	1 202	1 178
Lignite	1	TJ	101 000	1.0	1.5	101 426	99 397
Other bituminous coal	1	metric tonne (t)	2 441	0.0	0.0	2 441	2 392
Other bituminous coal	1	TJ	94 600	1.0	1.5	95 026	93 125
Sub-bituminous coal	1	metric tonne (t)	1 816	0.0	0.0	1 816	1 780
Sub-bituminous coal	1	TJ	9 6100	1.0	1.5	10 036	9 835
Brown coal briquettes	1	metric tonne (t)	2 018	0.0	0.0	2 018	1 978
Brown coal briquettes	1	TJ	97 500	1.0	1.5	97 926	95 967
Peat	1	metric tonne (t)	1 034	0.1	0.0	1 037	1 016
Peat	1	TJ	106 000	10	1.4	106 651	104 518
Municipal waste (non-biomass fraction)	1	metric tonne (t)	917	0.3	0.0	925	907
Coking coal	1	metric tonne (t)	2 668	0.0	0.0	2 668	2 615
Coking coal	1	TJ	94 600	1.0	1.5	95 026	93 125
Petroleum coke	1	metric tonne (t)	3 169	0.1	0.0	3 172	3 109
Petroleum coke	1	TJ	97 500	3.0	0.6	97 743	95 788
Coke oven coke	1	metric tonne (t)	3 017	0.0	0.0	3 017	2 957
Coke oven coke	1	TJ	107 000	1.0	1.5	107 426	105 277

SOLID WASTE FUELS

Source: Factors are for non-biomass fractions. IPCC 2006 stationary combustion

Fuel name	Amount of fuel	Units	kg CO_2
Municipal solid waste (non-biomass fraction)	1	TJ	91 700
Municipal solid waste (non-biomass fraction)	1	metric tonne	917
Industrial waste	1	TJ	143 000
Waste oils	1	TJ	73 300

Table A1.2: Default fugitive emission factors: Oil and gas production, storage and transport

Production type	Emission factor
Default fugitive methane emissions[12]	28 tonnes CO_2e/tonne CH_4 20 kg CO_2e/Nm^3 484.1 tonnes CO_2e/TJ
Onshore gas production	2.601E-02 tonnes CH_4/scf (standard cubic feet) 9.184E-01 tonnes CH_4/m
Offshore gas production	1.040E-02 tonnes CH_4/scf 3.673E-01 tonnes CH_4/m
Onshore oil production	2.346E-04 tonnes CH_4/bbl (barrels) 1.476E-03 tonnes CH_4/m
Offshore oil production	9.386E-05 tonnes CH_4/bbl 5.903E-04 tonnes CH_4/m
Gas processing plants	2.922E-02 tonnes CH_4/scf 1.032E+00 tonnes CH_4/m
Gas storage stations	6.767E+02 tonnes CH_4/station
Gas transmission pipelines CH_4 from pipeline leaks CO_2 from oxidation CO_2 from pipeline leaks	Total CH_4 = 2.235 tonnes CH_4/km-yr Total CO_2 = 1.33^{E-1} tonnes /km-yr Total CO_2e = 62.580 tonnes CO_2e /km-yr
Gas distribution pipelines CH_4 from pipeline leaks CO_2 from oxidation CO_2 from pipeline leaks	Total CH_4 = 1.002 tonnes CH_4/km-yr Total CO_2 = 4.12^{E-1} tonnes /km-yr Total CO_2e = 28.056 tonnes CO_2e /km-yr
Crude transmission pipelines	Negligible CH_4 fugitive equipment leak emissions
Refineries	Negligible CH_4 fugitive equipment leak emissions
LNG vaporisation using combustion	Total t CO_2 = Design throughput tonnes * 0.0393

Source: API Compendium, 2009 — Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry.

https://www.api.org/~/media/files/ehs/climate-change/2009_ghg_compendium.ashx

[12] Relative methane density of 0.716 kgCH_4/normal cubic metre (Nm^3) at a reference temperature of 0°C; based on average EU gross calorific value of 11.5 kWh/Nm3 [25/0], equivalent to an energy density of 57.84 MJ/kg CH_4 (from ENTSO-G 2018 TYNDP [Ten-year Network Development Plan] gas quality forecast for 2020; https://www.entsog.eu/sites/default/files/2019-02/entsog_tyndp_2018_GQO_0.pdf)

Table A1.3: Country-specific electricity emission factors

- Table A1.3 provides five different values for national country electricity grids with **all figures expressed in grams CO_2 per kilowatt hour (tonnes CO_2 per GWh)**. The figures are based on the IFI Dataset of Default Grid Factors v.3.2 from April 2022, which was created by the IFI Technical Working Group on GHG Accounting. The IFI dataset can be found here. The calculation methodology for the dataset can be found here.

Table A1.3 includes the following information:

- The combined margin for intermittent electricity generation, which should be used to calculate the baseline emissions for intermittent electricity generation such as solar, wind and tidal electricity generation.
- The combined margin for firm electricity generation, which should be used to calculate the baseline emissions for firm electricity generation such as hydro, geothermal and conventional fossil fuel-powered electricity generation, electricity consumption and electricity savings from energy efficiency measures.
- The emission factors for electricity consumption, including network losses. These emission factors for electricity consumption are used solely as the reference value for the calculation of electricity consumption and for transmission and distribution (T&D) losses and should not be used for the calculation of emissions from electricity generation projects. Where actual T&D losses are known, these can be used instead, as long as the sources are well documented. Typical projects using low-, medium- and high-voltage grids are as follows:
- HV (high voltage) grid — high-speed rail; heavy industry projects (e.g. mining, steel production)
- MV (medium voltage) grid — manufacturing plants; utilities
- LV (low voltage) grid — commercial; residential projects

For mobility projects, the following grid factors should be used:

- Electric trains and conventional rail infrastructure projects:
- > 15 kV: HV grid
- 3 kV: MV grid
- High-speed trains and high-speed rail infrastructure: HV grid
- Tram/metro/light rail projects: MV grid
- Electric vehicles (LDV/cars & vans; HDV/trucks & buses): LV grid
- Electric vehicle (EV) charging: LV grid (higher-power charging likely to be MV grid — to be verified during appraisal)

Emission factors in gCO_2/kWh (The impact of non-CO_2 GHGs is negligible. For calculation purposes, the factors below can be considered as CO_2e.)					
Country/territory/island	Combined margin intermittent electricity generation	Combined margin firm electricity generation/ electricity consumption	Electricity consumption/ network losses HV grid +2%	Electricity consumption/ network losses MV grid +4%	Electricity consumption/ network losses LV grid +7%
Afghanistan	331	193	197	201	207
Albania	0	0	0	0	0
Algeria	479	397	405	413	425
American Samoa (US)	664	516	526	536	552
Andorra	144	70	71	72	75
Angola	1 203	748	763	778	800
Anguilla (UK)	647	472	481	490	505
Antigua and Barbuda	654	489	499	509	524
Argentina	407	288	294	300	308
Armenia	321	205	209	213	219
Aruba	628	421	430	438	451
Australia	663	421	429	437	450
Austria	194	113	115	118	121
Azerbaijan	478	384	392	400	411
Azores (Portugal)	614	384	392	399	411
Bahamas	636	441	450	458	472
Bahrain	624	454	463	472	486
Bangladesh	484	412	420	428	441
Barbados	650	484	494	503	518
Belarus	359	292	297	303	312
Belgium	204	124	127	129	133
Belize	320	183	187	190	196
Benin	682	576	587	599	616
Bermuda (UK)	598	342	348	355	365
Bhutan	0	0	0	0	0
Bolivia, Plurinational State of	525	393	401	409	421
Bonaire (Netherlands)	620	400	408	416	428
Bosnia and Herzegovina	1 025	739	754	769	791
Botswana	1 330	1 070	1 092	1 113	1 145
Brazil	234	150	153	156	161
British Virgin Islands (UK)	628	420	429	437	450
Brunei Darussalam	578	407	415	423	436
Bulgaria	755	495	505	515	530
Burkina Faso	672	539	550	561	577
Burundi	333	197	201	205	211
Cambodia	874	588	600	611	629
Cameroon	545	354	361	369	379
Canada	312	213	218	222	228
Canary Islands (Spain)	633	435	444	452	465
Cape Verde	660	505	515	525	540
Cayman Islands	610	373	380	388	399
Central African Republic	146	77	78	80	82
Chad	688	581	592	604	622
Channel Islands (UK)	616	389	396	404	416

Emission factors in gCO_2/kWh (The impact of non-CO_2 GHGs is negligible. For calculation purposes, the factors below can be considered as CO_2e.)					
Country/territory/island	Combined margin intermittent electricity generation	Combined margin firm electricity generation/ electricity consumption	Electricity consumption/ network losses HV grid +2%	Electricity consumption/ network losses MV grid +4%	Electricity consumption/ network losses LV grid +7%
Chile	499	235	240	245	252
China (PRC and Hong Kong)	744	485	495	505	519
Colombia	334	208	213	217	223
Comoros	691	589	601	613	630
Congo, Democratic Republic of	0	0	0	0	0
Congo, Republic of	564	405	413	421	434
Cook Islands	628	422	430	439	451
Costa Rica	82	39	40	40	42
Côte d'Ivoire	409	314	321	327	336
Croatia	247	168	171	175	180
Cuba	496	391	399	407	419
Curacao/Netherlands Antilles	737	506	516	526	541
Cyprus	633	438	447	456	469
Czech Republic	736	461	471	480	494
Denmark	284	155	158	161	166
Djibouti	686	575	587	598	616
Dominica	633	433	442	450	463
Dominican Republic	536	426	435	443	456
Ecuador	455	280	286	291	300
Egypt	498	406	414	422	434
El Salvador	445	275	280	286	294
Equatorial Guinea	531	361	368	376	386
Eritrea	836	704	718	732	753
Estonia	895	625	638	650	669
Eswatini	0	0	0	0	0
Ethiopia	0	0	0	0	0
Falkland Islands (UK)	589	316	322	328	338
Faroe Islands (Denmark)	590	320	327	333	343
Fiji	525	334	341	348	358
Finland	209	114	116	119	122
France	124	68	69	70	72
French Guiana	340	200	204	208	214
French Polynesia	625	412	421	429	441
Gabon	791	533	544	554	570
Gambia	692	591	603	615	632
Georgia	231	135	138	141	145
Germany	523	313	319	325	335
Ghana	413	276	282	287	295
Gibraltar (UK)	625	369	376	384	395
Greece	447	346	353	360	370
Greenland	204	105	107	109	112
Grenada	666	523	533	544	559
Guadeloupe (France)	633	433	441	450	463
Guam	631	428	436	445	458

Emission factors in gCO_2/kWh (The impact of non-CO_2 GHGs is negligible. For calculation purposes, the factors below can be considered as CO_2e.)					
Country/territory/island	Combined margin intermittent electricity generation	Combined margin firm electricity generation/ electricity consumption	Electricity consumption/ network losses HV grid +2%	Electricity consumption/ network losses MV grid +4%	Electricity consumption/ network losses LV grid +7%
Guatemala	659	427	436	444	457
Guinea	643	460	469	478	492
Guinea-Bissau	687	577	589	600	618
Guyana	760	616	628	640	659
Haiti	942	765	780	795	818
Honduras	548	359	366	373	384
Hungary	257	191	195	199	204
Iceland	0	0	0	0	0
India	822	608	620	632	650
Indonesia	743	675	688	701	722
Iran, Islamic Republic of	528	421	429	438	450
Iraq	971	788	804	819	843
Ireland	309	189	193	197	203
Isle of Man (UK)	349	204	208	212	219
Israel	343	258	264	269	276
Italy	343	224	228	233	239
Jamaica	631	498	508	518	532
Japan	448	408	416	425	437
Jordan	474	382	390	397	409
Kazakhstan	698	532	543	554	569
Kenya	462	274	280	285	293
Kiribati	669	530	540	551	567
Korea (North), Democratic People's Republic of	606	359	367	374	385
Korea (South), Republic of	473	335	342	348	359
Kosovo	1 032	843	860	877	902
Kuwait	572	400	408	416	428
Kyrgyzstan	172	98	100	102	105
Lao People's Democratic Republic	876	555	566	577	593
Latvia	194	117	120	122	125
Lebanon	709	567	578	590	607
Lesotho	0	0	0	0	0
Liberia	564	374	381	389	400
Libya	602	493	503	513	528
Liechtenstein	114	52	53	54	56
Lithuania	170	102	104	106	109
Luxembourg	173	95	97	99	102
Madagascar	760	567	579	590	607
Madeira (Portugal)	552	369	376	383	394
Malawi	397	243	248	252	260
Malaysia	508	436	445	454	467
Maldives	667	524	535	545	561
Mali	906	623	636	648	667
Malta	435	295	300	306	315

Emission factors in gCO_2/kWh (The impact of non-CO_2 GHGs is negligible. For calculation purposes, the factors below can be considered as CO_2e.)					
Country/territory/island	Combined margin intermittent electricity generation	Combined margin firm electricity generation/ electricity consumption	Electricity consumption/ network losses HV grid +2%	Electricity consumption/ network losses MV grid +4%	Electricity consumption/ network losses LV grid +7%
Marshall Islands	681	561	572	583	600
Martinique (France)	623	406	415	423	435
Mauritania	663	513	523	534	549
Mauritius	641	543	554	564	581
Mayotte (France)	662	512	522	532	548
Mexico	467	359	366	373	384
Micronesia	679	557	568	579	596
Moldova, Republic of	488	399	407	415	427
Monaco	124	68	69	70	72
Mongolia	1 230	1 002	1 022	1 042	1 072
Montenegro	739	471	480	490	504
Montserrat	664	517	527	538	553
Morocco	660	547	558	569	585
Mozambique	188	111	113	115	119
Myanmar	602	407	415	423	435
Namibia	274	139	141	144	148
Nauru	666	521	531	542	557
Nepal	0	0	0	0	0
Netherlands	280	203	207	211	217
New Caledonia (France)	654	445	454	463	477
New Zealand	194	108	110	112	115
Nicaragua	562	372	379	387	398
Niger	752	718	732	747	768
Nigeria	463	358	365	372	383
Niue	642	459	468	477	491
North Macedonia, Republic of	743	563	574	585	602
Northern Mariana Islands (US)	626	416	425	433	445
Norway	36	17	17	18	18
Oman	419	320	326	332	342
Pakistan	515	386	393	401	413
Palau	657	497	507	517	532
Palestinian Authority	643	517	527	537	553
Panama	385	230	235	240	246
Papua New Guinea	491	315	321	328	337
Paraguay	0	0	0	0	0
Peru	390	252	257	262	270
Philippines	617	525	535	546	562
Poland	717	532	543	553	569
Portugal	329	228	232	237	244
Puerto Rico (US)	508	362	369	376	387
Qatar	411	258	263	268	276
Reunion (France)	641	421	429	438	450
Romania	414	289	295	301	310
Russian Federation	432	360	367	374	385

Emission factors in gCO_2/kWh (The impact of non-CO_2 GHGs is negligible. For calculation purposes, the factors below can be considered as CO_2e.)					
Country/territory/island	Combined margin intermittent electricity generation	Combined margin firm electricity generation/ electricity consumption	Electricity consumption/ network losses HV grid +2%	Electricity consumption/ network losses MV grid +4%	Electricity consumption/ network losses LV grid +7%
Rwanda	601	416	424	433	445
Saint Helena (UK)	641	456	465	474	488
Saint Kitts and Nevis	649	477	487	496	510
Saint Lucia	666	521	531	542	557
Saint Martin (France)	652	484	493	503	517
Saint Pierre and Miquelon (France)	626	415	423	431	444
Saint Vincent and Grenadines	658	499	509	519	534
Samoa	633	434	443	452	465
San Marino	343	224	228	233	239
São Tomé and Príncipe	682	565	576	587	604
Saudi Arabia	510	374	381	389	400
Senegal	790	656	669	682	702
Serbia	933	678	691	705	725
Seychelles	650	479	488	498	512
Sierra Leone	398	246	251	256	263
Singapore	311	200	204	208	214
Sint Martin (Netherlands)	644	463	472	482	495
Slovak Republic	269	164	167	170	175
Slovenia	494	285	291	296	305
Solomon Islands	681	563	574	585	602
Somalia	689	582	594	606	623
South Africa	964	786	801	817	841
South Sudan	820	704	718	732	753
Spain	329	209	213	217	223
Sri Lanka	646	506	516	526	541
Sudan	609	398	406	414	426
Suriname	855	565	576	587	604
Sweden	52	25	26	26	27
Switzerland	38	20	21	21	22
Syrian Arab Republic	650	546	557	568	585
Taiwan (Chinese Taipei)	427	331	338	344	354
Tajikistan	199	106	108	110	113
Tanzania, United Republic of	458	336	343	349	360
Thailand	413	351	358	365	375
Timor-Leste	691	589	601	613	630
Togo	761	597	609	621	639
Tonga	670	533	543	554	570
Trinidad and Tobago	488	370	377	385	396
Tunisia	423	348	355	362	372
Turkey	351	309	315	321	330
Turkmenistan	833	676	689	703	723
Turks and Caicos Islands (UK)	639	451	460	469	482
Tuvalu	657	497	506	516	531
Uganda	218	116	118	120	124

Emission factors in gCO_2/kWh (The impact of non-CO_2 GHGs is negligible. For calculation purposes, the factors below can be considered as CO_2e.)					
Country/territory/island	Combined margin intermittent electricity generation	Combined margin firm electricity generation/ electricity consumption	Electricity consumption/ network losses HV grid +2%	Electricity consumption/ network losses MV grid +4%	Electricity consumption/ network losses LV grid +7%
Ukraine	643	435	443	452	465
United Arab Emirates	464	310	317	323	332
United Kingdom, UK	320	219	223	227	234
United States, US	352	246	251	256	263
Uruguay	133	65	66	67	69
Uzbekistan	558	467	477	486	500
Vanuatu	659	504	514	524	539
Venezuela, Bolivarian Republic of	582	368	375	382	393
Vietnam	493	381	388	396	407
Virgin Islands (US)	546	373	380	388	399
Yemen	735	615	627	639	658
Zambia	334	197	201	205	211
Zimbabwe	1 315	880	898	915	942
European Union — 27	353	261	266	272	277
World	530	436	444	453	466

Source: Emission factors based on the IFI Dataset of Default Grid Factors v.3.0 from December 2021, created by the IFI Technical Working Group on GHG Accounting. The methodological approach can be found on the UNFCCC's website: https://unfccc.int/sites/default/files/resource/IFITWG_Methodological_approach_to_common_dataset.pdf

Table A1.4: Build margins for electricity and heat generation factors by unit[13]

Unit type	Fuel	Generation efficiency	Emission factor t CO_2e/TJ	Oxidised combustion	Emission factor t CO_2e/GWh
Electricity production					
Combined cycle gas turbine (CCGT)	Natural gas	0.57	56.2	0.995	353
	Light fuel oil	0.55	74.3	0.990	481
Open-cycle gas turbine (GT)	Natural gas	0.35	56.2	0.995	575
	Light fuel oil	0.35	74.3	0.990	757
Steam turbine combustion	Natural gas	0.44	56.2	0.995	457
	Light fuel oil	0.44	74.3	0.990	602
	Heavy fuel oil	0.44	77.6	0.990	629
Diesel engine combustion	Natural gas	0.44	56.2	0.995	457
	Light fuel oil	0.44	74.3	0.990	602
	Heavy fuel oil	0.44	77.6	0.990	629
Supercritical pulverised coal	Coal	0.44	98.7	0.980	791
	Lignite	0.42	101.4	0.980	851
Hydro, geothermal, wind, solar	Renewable	0	0.0	0	0
Nuclear	Uranium	0	0.0	0	0
Heat production					
Industrial steam boiler	Natural gas	0.93	56.2	0.995	216
	Light fuel oil	0.90	74.3	0.990	294
	Heavy fuel oil	0.90	77.6	0.990	308
Residential heat boiler	Natural gas	0.90	56.2	0.995	223
	Light fuel oil	0.85	74.3	0.990	312

Table A1.5: Integrated iron and steel emission factors by unit

Unit type	Emission factor	Units
Coke (excluding lignite coke)	0.24	t CO_2/t coke
Sintered ore	0.24	t CO_2/t sinter
Hot metal (Blast furnace + basic oxygen furnace)	1.44	t CO_2/t iron
Hot wide strip mills	0.10	t CO_2/t steel
Annealing line	0.06	t CO_2/t steel
Billet mills	0.26	t CO_2/t steel
Reversing mills	0.25	t CO_2/t steel
Medium section mills	0.25	t CO_2/t steel
Heavy section mills	0.29	t CO_2/t steel
Bar mills	0.16	t CO_2/t steel
Section mill	0.09	t CO_2/t steel
Secondary steelmaking	0.01	t CO_2/t liquid steel

Source: Refer to EU ETS Phase II New Entrants' Benchmark Review: Integrated Iron and Steel Benchmark Review Report http://www.decc.gov.uk/media/viewfile.ashx?filepath=what we do/global climate change and energy/tackling climate change/emissions trading/eu_ets/euets_phase_2/newenrants/benchmark_revi/file33265.pdf&filetype=4&minwidth=true and EU Taxonomy Climate Delegated Act page 195: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32021R2139&from=EN

[13] Assumptions for build margin technologies can be found in Annex 2.

Table A1.6: Glass production carbonate emission factors

Carbonate	Emission factor [t CO_2/t carbonate]
$CaCO_3$	0.44
$MgCO_3$	0.52
NA1CO_3	0.42
$BaCO_3$	0.22
Li2CO_3	0.60
K2CO_3	0.32
$SrCO_3$	0.30
$NaHCO_3$	0.52

Source: EU ETS Monitoring and Reporting Guidelines 2007 — Establishing guidelines for the monitoring and reporting of greenhouse gas emissions pursuant to Directive 2003/87/EC of the European Parliament and of the Council, Annex IX Table 1 (http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2007:229:0001:0085:EN:PDF)

Table A1.7: Transport emission factors

Road transport						
		EC (MJ/vkm)	TTW gCO_2e/ vkm	Average occupation/load	EC (MJ/pkm)	TTW CO_2e/ pkm or tkm
Cars						
Car average	Average	2.51	180	1.4	1.79	128
	Urban	3.36	240	1.4	2.40	172
Car diesel	Average	2.38	169	1.4	1.70	121
	Urban	3.11	220	1.4	2.22	157
Car gasoline	Average	2.68	195	1.4	1.91	139
	Urban	3.67	268	1.4	2.62	191
Car LPG (liquefied petroleum gas)	Average	2.68	180	1.4	1.91	129
	Urban	3.39	228	1.4	2.42	163
Car CNG (compressed natural gas)	Average	2.86	170	1.4	2.04	121
	Urban	3.86	229	1.4	2.76	164
Hybrid petrol	Average	1.81	128	1.4	1.30	92
	Urban	2.37	168	1.4	1.69	120
Car electric (average size)	Average	0.84	0	1.4	0.60	-
	Urban	0.73	0	1.4	0.52	-
Buses						
Average urban bus	Average	12.18	862	8.9	1.38	97
Urban buses midi <= 15 t	Average	9.96	705	6.7	1.50	106
Urban buses standard 15–18 t	Average	13.45	952	9.5	1.42	100
Urban buses articulated > 18 t	Average	16.89	1 196	19.0	0.89	63
Urban CNG buses (standard)	Average	21.60	1 284	9.5	2.27	135

Road transport						
		EC (MJ/vkm)	TTW gCO_2e/ vkm	Average occupation/load	EC (MJ/pkm)	TTW CO_2e/ pkm or tkm
Urban buses diesel hybrid (standard)	Average	11.42	809	9.5	1.20	85
Urban buses electric (standard)	Average	7.83	0	9.5	0.82	-
Coaches						
Coaches average	Average	11.06	783	34.4	0.32	23
Coaches standard <= 18 t	Average	10.55	746	25.0	0.42	30
Coaches articulated > 18 t	Average	11.92	844	50.0	0.24	17
Two-wheelers						
E-bike	Electric	0.05	0	1.0	0.05	-
Mopeds	Av. petrol	0.93	74	1.1	0.84	67
	Av. elect.	0.15	0	1.1	0.14	-
Motorcycle	Average	1.39	102	1.2	1.21	88
LCVs						
LCV average	Average	3.41	241			
HGVs						
HGV average	Average	8.53	604	7.8	1.09	77
HGV rigid <= 7.5 t	Average	4.44	315	0.9	5.14	364
HGV rigid 7.5–16 t	Average	6.57	465	2.6	2.52	178
HGV rigid 16–32 t	Average	8.90	630	6.0	1.50	106
HGV rigid > 32 t	Average	11.14	789	15.1	0.74	52

Source: COPERT (Emissions calculation tool produced by EEA) completed with STREAM (CE Delft)

Rail passenger						
		EC (MJ/seat-km)	TTW gCO_2e/ seat-km	Average occ. rate (%)	EC (MJ/tkm)	TTW CO_2e/ pkm
Electric	Average	0.11	-	35%	0.31	0.0
	Regional/suburban	0.09	-	25%	0.35	0.0
	Intercity	0.12	-	36%	0.34	0.0
	High-speed	0.11	-	48%	0.22	0.0
Diesel	Average	0.26	18.5	24%	1.09	76.9
	Regional/suburban	0.22	15.4	20%	1.10	76.9
	Intercity	0.31	21.7	28%	1.09	76.9
Average	Average	0.00	0.0			6.4

Source: Union internationale des chemins de fer

Rail freight						
		EC (MJ/vkm)	TTW gCO_2e/ vkm	Load (tonne)	EC (MJ/tkm)	TTW CO_2e/ tonne-km
Electric average	Av. train (1 000t - 21W)	59.8	-	516	0.116	0.0
Electric bulk	Av. train (1 000t - 18W)	59.8	-	597	0.100	0.0
Electric volume	Av. train (1 000t - 26W)	59.8	-	400	0.150	0.0
Electric container	Av. train (1 000t - 21W)	59.8	-	563	0.106	0.0
Diesel average	Av. train (1 000t - 21W)	161.5	11 434	516	0.313	22.2
Diesel bulk	Av. train (1 000t - 18W)	161.5	11 434	597	0.271	19.2
Diesel volume	Av. train (1 000t - 26W)	161.5	11 434	400	0.404	28.6
Diesel container	Av. train (1 000t - 21W)	161.5	11 434	563	0.287	20.3

Source: Ecotransit 2018

Inland waterways transport						
	Vessel type	EC (MJ/vkm)	TTW gCO_2e/vkm	Load (tonne)	EC (MJ/tkm)	TTW CO_2e/ tkm
Inland ships bulk	Rhine-Herne canal vessel (1 537t)	323	22 865	807	0.40	28.3
	Large Rhine vessel (3 013t)	347	24 564	1 665	0.21	14.8
	4-barge push convoy (11 181t)	1 203	85 161	6 178	0.19	13.8
Container	Europe IIa push convoy (160 TEU)	411	29 095	912	0.45	31.9
	Large Rhine vessel (208 TEU)	307	21 733	1 186	0.26	18.3

Source: STREAM Freight 2016 (CE Delft)

Shipping						
Type (unit)		EC (MJ/vkm)	TTW kg CO_2e/ vkm	Load (tonne)	EC (MJ/tkm)	TTW gCO_2e/ tkm
Bulk carrier (dwt)	0–9 999	730	56.74	2 335	0.313	24.3
Bulk carrier (dwt)	10 000–34 999	1 615	125.63	14 935	0.108	8.4
Bulk carrier (dwt)	35 000–59 999	2 144	166.72	26 089	0.082	6.4
Bulk carrier (dwt)	60 000–99 999	2 633	204.76	35 036	0.075	5.8
Bulk carrier (dwt)	100 000–199 999	3 677	285.99	89 812	0.041	3.2
Bulk carrier (dwt)	200 000+	5 435	422.75	150 873	0.036	2.8
Chemical tanker (dwt)	0–4 999	680	52.91	1 899	0.358	27.9

Shipping						
Type (unit)		**EC (MJ/vkm)**	**TTW kg CO_2e/ vkm**	**Load (tonne)**	**EC (MJ/tkm)**	**TTW gCO_2e/ tkm**
Chemical tanker (dwt)	5 000–9 999	1 270	98.79	5 367	0.237	18.4
Chemical tanker (dwt)	10 000–19 999	1 615	125.63	9 705	0.166	12.9
Chemical tanker (dwt)	20 000+	2 448	190.40	22 346	0.110	8.5
Container (TEU)	0–999	1 299	101.00	5 344	0.243	18.9
Container (TEU)	1 000–1 999	2 694	209.52	12 139	0.222	17.3
Container (TEU)	2 000–2 999	3 262	253.75	18 808	0.173	13.5
Container (TEU)	3 000–4 999	4 002	311.27	26 755	0.150	11.6
Container (TEU)	5 000–7 999	5 239	407.49	36 392	0.144	11.2
Container (TEU)	8 000–11 999	6 460	502.45	51 391	0.126	9.8
Container (TEU)	12 000–14 500	7 292	567.19	78 668	0.093	7.2
General cargo (dwt)	0–4 999	414	32.23	1 545	0.268	20.9
General cargo (dwt)	5 000–9 999	1 090	84.76	4 498	0.242	18.8
General cargo (dwt)	10 000+	2 627	204.33	12 186	0.216	16.8
Liquefied gas tanker (cbm)	0–49 999	735	57.19	3 444	0.213	16.6
Liquefied gas tanker (cbm)	50 000–199 999	4 864	378.28	42 489	0.114	8.9
Liquefied gas tanker (cbm)	200 000+	7 004	544.73	53 619	0.131	10.2
Oil tanker (dwt)	0–4 999	814	63.29	1 655	0.492	38.2
Oil tanker (dwt)	5 000–9 999	1 659	129.06	4 902	0.338	26.3
Oil tanker (dwt)	10 000–19 999	2 429	188.90	9 501	0.256	19.9
Oil tanker (dwt)	20 000–59 999	2 523	196.21	14 968	0.169	13.1
Oil tanker (dwt)	60 000–79 999	2 962	230.39	25 564	0.116	9.0
Oil tanker (dwt)	80 000–119 999	3 476	270.36	37 499	0.093	7.2
Oil tanker (dwt)	120 000–199 999	4 406	342.68	58 092	0.076	5.9
Oil tanker (dwt)	200 000+	6 202	482.36	134 417	0.046	3.6
Refrigerated bulk (dwt)	0–1 999	2 467	191.87	3 810	0.647	50.4

Source: IMO-UCL Study 2015

Passenger aviation							
	Type	**EC (MJ/seat-km)**	**TTW gCO_2e/ seat-km**	**Average occ. rate (%)**	**EC (MJ/pkm)**	**Without RF TTW g CO_2e/ pkm**	**With RF TTW gCO_2e/ pkm**
Domestic	Average passenger	1.61	116	74%	2.2	158	298
Short-haul	Average passenger	0.95	69	80%	1.2	86	162
Long-haul	Average passenger	1.15	83	74%	1.6	112	212
International	Average passenger	1.07	77	80%	1.3	97	183
	Economy class	0.82	59	80%	1.0	74	140
	Premium economy class	1.31	94	80%	1.6	118	224
	Business class	2.37	171	80%	3.0	215	406
	First class	3.27	236	80%	4.1	296	560

Source: DEFRA (Department for Environment, Food and Rural Affairs)

Aviation freight				
	Type	**EC (MJ/tkm)**	**Without RF TTW gCO_2e/ tkm**	**With RF TTW gCO_2e/tkm**
Freight	Domestic, to/from UK	42.8	3 084	5 833
	Short-haul, to/from UK	14.3	1 029	1 946
	Long-haul, to/from UK	9.0	651	1 232
	International, to/from non-UK	9.0	651	1 232

Source: DEFRA

Table A1.8: Reservoir GHG emission factors

Source: IPCC Good Practice Guidance for LULUCF (land use, land-use change and forestry), 2003, Table 3A.3.5

GUIDANCE: *The key default values needed to implement the EIB methodologies are emission factors for CO_2, CH_4 and N_2O via the diffusion pathways and an emission factor for CH_4 via the bubbles pathways. The table below provides default emission factors for various climate zones that can be used. These default emission factors integrate some spatial and temporal variations in the emissions from reservoirs, as well as fluxes at the water–air interface of reservoirs. All default data have been obtained from measurements in hydroelectric or flood control reservoirs. The emission factors for the ice-free period should be used for the entire year.*

	Diffusive emissions (ice-free period) Ef (GHG)diff (kg ha-1 d-1)		
Climate	**CH_4**	**CO_2**	**N_2O**
Boreal, wet	0.11 ± 88%	15.5 ± 56%	0.008 ± 300%
Cold temperate, wet	0.2 ± 55%	9.3 ± 55%	nm
Warm temperate, dry	0.063 ± 0.032	-3.1 ± 3.6	nm
Warm temperate, wet	0.096 ± 0.074	13.2 ± 6.9	nm
Tropical, wet	0.64 ± 330%	60.4 ± 145%	0.05 ± 100%
Tropical, moist — long dry season	0.31 ± 190%	11.65 ± 260%	nm
Tropical, moist — short dry season	0.44 ± 465%	35.1 ± 290%	nm
Tropical, dry	0.3 ± 115%	58.7 ± 270%	nm
	Bubbles emissions (ice-free period) Ef (GHG) bubble (kg ha-1 d-1)		
Boreal, wet	0.29 ± 160%	ns	ns
Cold temperate, wet	0.14 ± 70%	ns	ns
Tropical, wet	2.83 ± 45%	ns	ns
Tropical, moist — long dry season	1.9 ± 155%	ns	ns
Tropical, moist — short dry season	0.13 ± 135%	ns	ns
Tropical, dry	0.3 ± 324%	ns	ns
	Emissions associated with the ice cover period Ei (GHG) diff + Ei (GHG) bubble (kg ha-1 d-1)		
Boreal, wet	0.05 ± 60%	0.45 ± 55%	nm

Note: nm = not measured, ns = not significant.

Table A1.9: IPCC global warming potential factors

Source: IPCC Fifth Assessment Report, 2014 (AR5) from the GHG Protocol Corporate Accounting and Reporting Standard, 2018

Gas	Chemical formula	Global warming potential (100-year time horizon)
Carbon dioxide	CO_2	1
Methane	CH_4	28
Nitrous oxide	N_20	265
Hydrofluorocarbons (HFCs)		
HFC-23	CHF_3	12 400
HFC-32	CH_2F_3	677
HFC-41	CH_3F	116
HFC-43-10mee	$C_5H_2F_{10}$	1 650
HFC-125	C_2HF_5	3 170
HFC-134	$C_2H_2F_4$ (CHF_2CHF_2)	1 120
HFC-134a	$C_2H_2F_4$ (CH_2FCF_3)	1 300
HFC-143	$C_2H_3F_3$ (CHF_2CH_2F)	328
HFC-143a	$C_2H_3F_3$ (CF_3CH_3)	4 800
HFC-152a	$C_2H_4F_2$ (CH_3CHF_2)	138
HFC-227ea	C_3HF_7	3 350
HFC-236fa	$C_3H_2F_6$	8 060
HFC-245ca	$C_3H_3F_5$	716
Hydrofluoroethers (HFEs)		
HFE-449sl (HFE-7100)	$C_4F_9OCH_3$	421
HFE-569sf2 (HFE-7200)	$C_4F_9OC_2H_5$	57
Perfluorocarbons (PFCs)		
Perfluoromethane (tetrafluoromethane) PFC-14	CF_4	6 630
Perfluoroethane (hexafluoroethane) PFC-116	C_2F_6	11 100
Perfluoropropane PFC-218	C_3F_8	8 900
Perfluorobutane PFC-3-1-10	C_4F_{10}	9 200
Perfluorocyclobutane PFC-318	c-C_4F_8	9 540
Perfluoropentane PFC-4-1-12	C_5F_{12}	8 550
Perfluorohexane PFC-5-1-14	C_6F_{14}	7 910
Sulphur hexafluoride	SF_6	23 500

ANNEX 2: APPLICATION OF ELECTRICITY GRID EMISSION FACTORS FOR PROJECT BASELINES

1. ELECTRICITY-GENERATION PROJECTS

With respect to energy-generation projects, it is recommended that for grid-connected electricity generating projects, a combined margin, which is a weighted average of operating margin and build margin, should be used to define the baseline emissions of the project. For this purpose, the EIB will use the figures from the IFI Dataset of Default Grid Factors v.2.0 from July 2021, which was created by the IFI Technical Working Group on GHG Accounting.

1.1 Operating margin

The operating margin (OM) is the emission factor associated with power plants' current electricity generation that would be affected by the proposed project activity. In principle, it would comprise power plants operating on the margin of the generation dispatch merit order and could include any type of generation. For special cases (peak power, pumped storage or direct replacement), specific marginal plants can be assumed for the OM. However, as a reference for most projects, it is assumed that the OM consists of generation from the power plants with the highest variable operating costs in the electricity system, mainly natural gas and oil, and coal and lignite generation if solid fossil fuels make up a large proportion of the generation mix. Renewable, nuclear and "must-run" fossil fuel-fired generation — such as combined heat and power plants for district heating, which would not be affected by the project — are generally excluded from the OM.

1.2 Build margin

The build margin (BM) is the emission factor that refers to power plants' construction and future operations that would be affected by the proposed project activity. The EIB takes a five-year forward-looking perspective when determining the BM technologies.

In principle, gas, fuel oil, coal, lignite, renewable energy (mainly intermittent) and nuclear plants may be built and could be part of the BM. However, for simplicity and taking a conservative position on CO_2 emissions savings made by renewable energy, in mainland Europe, where natural gas is available, the BM for base load power plants connected to the grid will be assumed to be 100% based on the emissions from combined cycle gas turbine (CCGT) technology. On isolated islands, grids where gas is not available or where large-scale power plants are not feasible, the BM will be based on the most appropriate fuel oil alternative (CCGT or diesel engine). For peak load generation, the most appropriate alternative may include a combination of base load and peak load power plants (open cycle gas turbines or diesel engines). The BM for heat boilers will be based on natural gas, where gas distribution networks are available, or on fuel oil otherwise.

The same principles apply for the baseline in countries beyond Europe, except for countries where large-scale power plants are required and gas is not available. In these countries, the only viable thermal alternative will include coal. In addition, where significant sources of hydro and geothermal power are available (firm as opposed to intermittent), renewable energy may also make a significant contribution to the baseline.

A harmonised approach to calculating the BM has been agreed with IFIs[14] and a harmonised dataset has been produced. It can be found in Table A1.3.

[14] IFI Approach to GHG Accounting for Renewable Energy Projects, November 2015 (www-wds.worldbank.org)

2. PURCHASED ELECTRICITY

Projects that purchase electricity from the grid must take into account the losses from the transmission and distribution (T&D) of the electricity. The size of the losses will depend on the project's capacity (that is, whether it is connected to the high-, medium- or low-voltage grid). The grid emission factors, including T&D losses, are located in Table A1.3 in the methodologies. For simplicity, T&D losses are assumed to be as follows:

- High-voltage grid: 2% T&D losses. Projects with > 10 MW consumption generally will be connected to the high-voltage grid (e.g. high-speed rail, large heavy industry projects)
- Medium-voltage grid: 4% T&D losses. This includes most industry projects.
- Low-voltage grid: 7% T&D losses. This includes all residential and commercial projects.

3. NETWORK INVESTMENTS — GAS AND ELECTRICITY

Networks are transporters of energy and are usually mandated to meet supply requirements/demand growth. The baseline will usually supply the same amount of energy as the project, either less efficiently (without the project) or using similar new infrastructure (no economic alternative). For the purposes of the EIB's carbon footprint methodology, the investments in gas and electricity transmission and distribution networks are divided into three categories. Each category is characterised by its objectives and its contribution to GHG emissions:

i) Some investments are primarily intended to improve commercial operations, service quality and/or security of supply. These investments may facilitate customer billing or reduce operation and maintenance costs, or they may be required by the regulator or mandated to meet new environmental/safety standards. The investments are characterised as having little or no impact on GHG emissions, and their effects are excluded from the carbon footprint calculation.

ii) Other investments are required to maintain the condition of the existing network. These investments are characterised by the **rehabilitation/replacement** of existing assets and are intended to ensure the long-term supply of electricity or gas. Energy losses (for electricity transmission and distribution networks), energy consumption (for gas transmission and distribution networks) and fugitive emissions (for gas distribution networks) are the main sources of GHG emissions. The carbon footprint for these investments is based on a percentage share of the total emissions for the network that is in proportion with the percentage share of the network assets replaced or rehabilitated.

   Calculation: CO_2 emissions are estimated for the entire network, and an emission factor per unit of supply is calculated. The volume of supply used is that of the last year of operation prior to the project construction starting. Assumptions are made about the emission factor with and without the project. In most cases, emissions for the current level of supply would go up without the investment. The percentage share of the network assets replaced/rehabilitated is estimated. Carbon footprints (absolute and baseline) are calculated using this percentage share of the total emissions of the network (with and without the project) for the pre-project levels of demand.

iii) Still other investments are required to meet growing demand. These investments are characterised by **network extensions**, upgrades of capacity and new connections. In reality, these investments are difficult to separate physically from the rehabilitation and replacement of assets or even from those required for commercial or regulatory reasons, but their GHG emissions impact is related to increasing the supply of electricity or gas through the entire network.

   Calculation: CO_2 emission factors (with and without the project) per unit of supply are estimated as above. These factors are applied to the incremental demand that is accommodated as a result of the project (typically 3–4 years of demand growth). All emissions associated with the incremental demand are attributed to the project.

ANNEX 3: FORESTRY CARBON FOOTPRINT CALCULATION METHODOLOGY

The operational boundary of forestry projects, which defines the emission sources to be included for forestry projects, includes:

- **Scope 1 emissions**
  - Fuel consumption associated with site preparation, management, etc.
  - Emissions from fertiliser use
- **Scope 2 emissions**
  - Electricity consumption
- **Scope 3 emissions**
  - Not included
- **Carbon sequestration**
  - Carbon sequestration due to biomass growth
  - Loss of carbon sequestration due to biomass removals (e.g. thinning and harvesting)

The absolute emissions are measured as the average annual emissions over the project lifetime:

$$\begin{aligned} Absolute\ emissions \left(\frac{t\ CO_2e}{year}\right) &= average\ annual\ fuel\ consumption\ emissions \left(\frac{t\ CO_2e}{year}\right) \\ &+ average\ annual\ fertiliser\ consumption\ emissions \left(\frac{t\ CO_2e}{year}\right) \\ &+ average\ annual\ scope\ 2\ emissions \left(\frac{t\ CO_2e}{year}\right) \\ &- average\ annual\ carbon\ sequestration \left(\frac{t\ CO_2e}{year}\right) \end{aligned}$$

Emissions and carbon sequestration levels are calculated on an average annual basis over the full rotation cycle (economic lifetime) of the forest and not only the project lifetime. Taking an average over this time period is important as biomass growth and carbon sequestration is not linear for forest growth due to changing growth rates depending on the forest management regime applied, the impact of thinning and harvesting, other management interventions and natural conditions. GHG emissions and removals related to the management of forest resources are accounted for as per the LULUCF Regulation (EU) 2018/841. Wood removals, as part of sustainable forest management practices (such as tending, thinning and final cuts followed by forest regeneration), increase carbon sequestration at a general forest inventory level in comparison to unmanaged or poorly managed forests.

Unmanaged or poorly managed forests have much lower growth rates as compared to sustainably managed forests. In addition, sustainable forest management activities also apply the concept of preserving high biodiversity and high carbon stock areas such as peatlands. The economic lifetime is generally aligned with the time of harvesting, meaning that GHG removals from harvesting are accounted for when calculating the average annual carbon sequestration.

The *average annual fuel consumption emissions* related to forest management are calculated by multiplying the average annual fuel consumption over the forest's economic lifetime (e.g. diesel, gasoline, etc.) with the standard fuel-specific emission factor (e.g. kg CO_2e/litre).

The *average annual fertiliser consumption emissions* (on the field) are calculated by multiplying the input consumption (e.g. tonnes of fertiliser) with an input-specific emission factor (t CO_2e/t of input) from acknowledged databases such as Ecoinvent or emission factor information from the input producer.

When calculating the *average annual carbon sequestration* in forest biomass, the EIB accounts for annual forest biomass growth (annual increment) as well as forest biomass reductions due to forest tending, thinning and harvesting activities within the full economic lifetime (rotation cycle) of the forest (which is typically longer than the project lifetime). Such biomass reductions are directly subtracted from the carbon sequestered.

Carbon sequestration is accounted for both below-ground and above-ground biomass. Based on the IPCC Guidelines for National GHG Inventories,[15] the following formula is used to calculate the average annual carbon sequestration of the EIB's forestry projects, measured in t CO_2e/year:

$$Average\ annual\ carbon\ sequestration\ \left(\frac{t\ CO_2e}{year}\right) = \left[MAI\left(\frac{\frac{m^3}{ha}}{year}\right)\right] x\ [BCEF]\ x\ [1 + R]\ x\ \left[CF\ \left(\frac{t\ C}{t\ dry\ matter}\right)\right] x\ \left[CCF\ \left(\frac{t\ CO_2e}{t\ C}\right)\right] x\ [Forest\ area\ (ha)],$$

where:

- *MAI*, which is the *mean annual increment* (or mean annual growth), refers to the average growth per year of a forest stand, which is a variable depending on the specific local site and climate conditions, tree species, rotation period, forest management practices applied (e.g. intensity of tending/thinning operations), etc. The MAI used by the EIB is calculated for the local specific conditions and forest management practices applied in each project. The information on MAI is provided by project promoters at the project appraisal stage and then scrutinised against the EIB's own expert knowledge and default MAI values from sources such as the Food and Agriculture Organisation of the United Nations (FAO)'s data on forest growth[16] or the IPCC Guidelines for National GHG Inventories.
- *BCEF*, which is the *biomass conversion and expansion factor*, refers to the expansion factor of merchantable growing stock volume to above-ground biomass. BCEF transforms the merchantable volume of growing stock directly into its above-ground biomass. BCEF values are more convenient because they can be applied directly to volume-based forest inventory data and operational records without having to resort to basic wood densities (D). They provide the best results when they have been derived locally and based directly on merchantable volume. However, if BCEF values are not available, and if the biomass expansion factor (BEF) for wood removals — which is dimensionless — and wood density (D) values are separately estimated, the following conversion can be used:

  $$BCEF = BEF\ x\ D\ (\frac{t}{m^3})$$

  If country-specific data on roundwood removals are not available, expert knowledge or FAO statistics on wood harvests will be used. Given that FAO statistical data on wood harvests exclude bark, the FAO statistical wood harvest data without bark will be multiplied by a default expansion factor of 1.15 to convert it into merchantable wood removals including bark.
- *D (wood density)* refers to basic wood density (expressed in tonnes/m^3), which varies by species and climate conditions (0.2 to 0.9 in tropical forests and 0.3 to 0.6 in temperate forests). Wood density is conservatively estimated based on expert knowledge and available reference documents,[17] and the default value used is 0.5 tonnes/m^3.

[15] 2006 IPCC Guidelines for National Greenhouse Gas Inventories — Volume 4: Agriculture, Forestry and Other Land Use.
[16] FAO's Global Planted Forests Assessment: Global Planted Forests Thematic Study (2006).
[17] Overview of wood densities for several different tree species from Estimating Biomass and Biomass Change of Tropical Forests: A Primer. (FAO Forestry Paper - 134); 2006 IPCC Guidelines for National Greenhouse Gas Inventories – Volume 4: Agriculture, Forestry and Other Land Use.

- *R* refers to the *ratio of below-ground biomass to above-ground biomass*, or the root-to-shoot ratio for a specific vegetation type in tonnes of dry matter below-ground biomass (tonnes of dry matter above-ground biomass)$^{-1}$. R is conservatively estimated based on expert knowledge and available reference documents and must be set to zero when assuming no changes in below-ground biomass allocation patterns.
- *CF* is a conversion factor that refers to the *carbon fraction of dry matter* expressed in tonnes of carbon per tonne of dry matter. Using a conservative approach of default values for wood carbon content,[18] the default CF *value* assumed in calculations is 0.5 (t C/t dry matter).
- CCF is the carbon conversion factor from C to CO_2e, calculated as follows:

$$conversion\ factor\ from\ C\ to\ t\ CO_2e = \frac{12 + (16\ x\ 2)}{12} = 3.67$$

- *Forest area (ha)* is the project's forest area provided by the promoter and verified by the EIB.

After having calculated the absolute emissions from the project and the absolute emissions of the baseline (calculated based on the same methodology as in the "with" project scenario), the relative emissions can be estimated. The relative emissions are calculated by subtracting the baseline absolute emissions from the project absolute emissions:

$$Relative\ emissions\ \left(\frac{t\ CO_2e}{year}\right) = Project\ absolute\ emissions\ \left(\frac{t\ CO_2e}{year}\right) - \ Baseline\ absolute\ emissions\ \left(\frac{t\ CO_2e}{year}\right)$$

For the baseline definition, the EIB assumes a zero baseline absolute emissions/sequestration for afforestation projects, while it does not assume a zero baseline for forest rehabilitation where, for example, the MAI is improved through forestry management practices in comparison to the baseline. The reason is that in case of forest rehabilitation, a forest is generally already existing but is either unmanaged or poorly managed, meaning that carbon is also sequestered in the baseline scenario, however at a lower level when compared to sustainably managed forests.

Alternatively, in the absence of reliable data for calculating the GHG emissions based on the methodology described above, the Bank may use the default emissions/sequestration values from the IPCC Guidelines for National GHG Inventories[19] or the Ex-Ante Carbon-balance Tool (EX-ACT),[20] which is an appraisal system developed by the FAO to provide estimates of the impact of agriculture and forestry development projects, programmes and policies on the carbon balance.

[18] At present, 50% carbon content (w/w or "weight by weight", the proportion of carbon compared to wood mass, as measured by weight) is widely promulgated as a generic value for wood. Carbon in kiln-dried hardwood species, for example, ranges from 46.27% to 49.97% (w/w) and from 47.21% to 55.2% in conifers. See Lamlom and Savidge's (2003) "A Reassessment of Carbon Content in Wood: Variation Within and Between 41 North American Species."
[19] 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 4: Agriculture, Forestry and Other Land Use, Chapter 4 — Forest Land, Section 4.5.
[20] FAO Ex-Ante Carbon-balance Tool (EX-ACT): http ://www.fao.org/tc/exact/ex-act-home/en/.

ANNEX 4: LAND USE CHANGE CARBON-BALANCE CALCULATION USING EX-ACT

The agriculture and forestry sectors are of key concern in meeting climate change challenges, both because these sectors are responsible for a significant share of GHG emissions and because they could potentially play an important role in climate change mitigation at the same time. For instance, well-designed forestry and agriculture projects can play an important role in climate change mitigation, either by reducing emissions or by sequestering carbon in soil and biomass.

However, one of the main barriers to embracing the mitigation potential of the agriculture and forestry sectors is the lack of methodologies or approaches that would help project designers to integrate significant mitigation effects into agriculture and forestry development projects.

The IPCC has published guidelines and good practices for GHG accounting (IPCC, 2006), and various tools have been developed to help those performing GHG assessments within these guidelines. These tools provide a framework for the assessments and a database of emission factors and can be classified as calculators, protocols, guidelines and models.

The EX-ACT was developed by the FAO to provide ex ante measurements of the impact of agriculture and forestry development projects on GHG emissions and carbon sequestration, indicating their effects on the carbon balance. The EIB can use EX-ACT for projects in the agriculture, forestry and other land use (AFOLU) subsectors including (among others) cropland agriculture, forestry, livestock and fisheries.

EX-ACT version 8 was developed using primarily the 2006 Guidelines for National Greenhouse Gas Inventories (IPCC, 2006) and the 2013 Supplement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories: Wetlands (IPCC, 2013). It was complemented by other existing methodologies and reviews of default coefficients, where available. Embodied GHG emissions for farm operations, inputs, transportation and irrigation systems implementation are from Lal (2004). Emission factors for the fisheries sector are based on the scientific literature from Parker and Tyedmers (2014), Sciortino (2010), Winther *et al.* (2009) and Irribaren *et al.* (2010, 2011). EX-ACT (version 9) is currently being upgraded according to the IPCC's Refinement to the 2006 Guidelines for National Greenhouse Gas Inventories (IPCC, 2019).

Structure of EX-ACT.[21] EX-ACT consists of a set of 18 linked Microsoft Excel sheets into which project sector experts insert information on dominant soil types and climatic conditions of the project area, together with basic data on land use, land use change and land management practices anticipated under projects' activities as compared to a "business-as-usual" scenario. EX-ACT adopts a modular approach. Each "module" describes a specific land use and follows a three-step logical framework:

(i) General description of the project (geographic area, climate and soil characteristics, duration of the project);
(ii) Identification of changes in land use and technologies anticipated in line with project components (deforestation, afforestation/reforestation, annual/perennial crops, rice cultivation, grasslands, livestock, inputs, energy); and
(iii) Computation of the carbon balance with and without the project using IPCC default values and, when available, ad hoc coefficients.

[21] http://www.fao.org/tc/exact/ex-act-home/en/

Methodologies behind EX-ACT.[22] EX-ACT is based on the six broad categories (and sub-categories) proposed for reporting GHG inventories but is focused mostly on three categories: forestland, cropland and grassland. Three approaches may be used to represent areas under a specific land use depending on the level of detail of the available information. The tool considers information on conversions between categories but without full, spatially explicit, location data. The result of this approach can be represented as a land-use change matrix between categories.

When performing an ex ante analysis, the user should have an idea of:

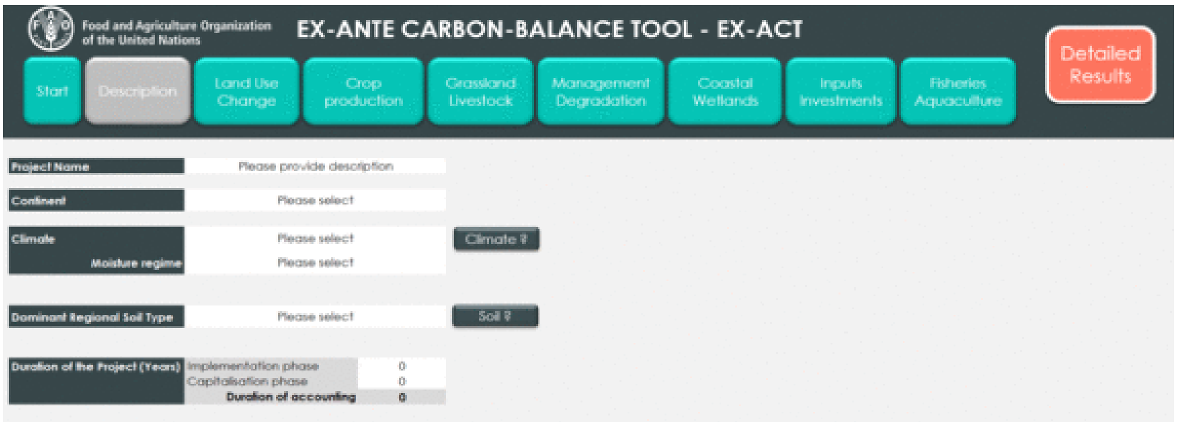
(i) What would happen without the project (the business-as-usual scenario, or as it is referred to in this document, the "baseline" linking to the overall EIB GHG footprint methodology). Thus, the final balance is the comparison between the GHG emissions associated with the project versus the baseline scenario.

(ii) The definition of the two time periods — one for the implementation phase (the active phase of the project commonly corresponding to the funding and investment phase) and another for the capitalisation phase (a period where the benefits of the investment are still occurring and may be attributed to the changes induced by the adoption of the project).

Generic methodologies for estimating carbon pools changes (CO_2 balance): Changes in carbon pools are calculated using methods that can be applied in a very similar way to the type of land use change (generic methods). Generic methodologies are used mainly to account for changes between two categories during conversion and concern the five pools defined by IPCC guidelines and the UNFCCC: above-ground biomass, below-ground biomass, soil, deadwood and litter. Most calculations, except where specified, use a default value with a stock difference method for CO_2 emissions, calculated as the change of carbon stocks for the different pools. Default values are proposed for each pool of each category (or sub-category, or even main vegetation type).

Generic methodologies for non-CO_2 GHG: For N_2O and CH_4 emissions, the generic approach consists of multiplying an emission factor for a specific gas or source category with activity data related to the emission source (e.g. area, animal numbers or mass unit). Emissions of N_2O and CH_4 are either associated with a specific land use category or sub-category (e.g. CH_4 emissions from rice) or are estimated using project-aggregated data (e.g. emissions from livestock and N_2O emissions from fertilisers). CH_4 and N_2O emissions are converted into CO_2e emissions based on the global warming potential of each gas. The user has the ability to use either the official values under the Kyoto Protocol of the UNFCCC or the last update provided by the IPCC (2007).

The tool can be downloaded from the http://www.fao.org/tc/exact/ex-act-home/en/ website, where the user manual is available in various languages.



[22] Bernoux *et al.* (2010). Ex-ante greenhouse gas balance of agriculture and forestry development programs. Sci. Agric. (Piracicaba, Braz.), v.67, n.1, pp. 31–40.

ANNEX 5: PORTS AND AIRPORTS CARBON FOOTPRINT CALCULATION METHODOLOGY

Airports

Absolute GHG emissions
To calculate the absolute airport GHG emissions, the following formula is used:

$$\begin{aligned}&\mathit{Absolute\ GHG\ emissions}\\&= \mathit{Scope}\ 1\ \&\ 2\ \mathit{GHG\ emissions}\\&+ \mathit{Scope}\ 3\ \mathit{GHG\ emissions\ from\ the\ landing\ and\ takeoff}\ (\mathit{L}\mathrm{TO})\ \text{cycle (including engine run}\\&- \text{up and testing, auxiliary power units (APUs), etc.)}\end{aligned}$$

The ***scope 1 and 2 GHG emissions*** are calculated by multiplying the average additional traffic of an airport project (the additional number of passengers that can be handled through the airport extension) by an average GHG emission factor per passenger. The average GHG emission factor per passenger is calculated as the weighted average scope 1 and 2 GHG emission factors of airports that report their scope 1 and 2 GHG emissions under the Airport Carbon Accreditation (ACA) scheme. The EIB uses GHG emission factors for small and large airports to account for the impact of a scale increase (e.g. larger planes, etc.).

The ***scope 3 emissions from the landing and takeoff (LTO) cycle (including engine run-up and testing, APUs, etc.)*** are based on average GHG emission factors for the LTO and cruise cycle GHG emissions of the average flight operating from the airport. The GHG emission factors are expressed in gCO_2e emissions per passenger.

Relative GHG emissions
The following calculation is used for relative GHG emissions for airports:

$$\begin{aligned}&\mathit{Relative\ GHG\ emissions} =\\&+\mathit{generated\ traffic\ GHG\ emissions} - \mathit{surface\ access\ GHG\ emission\ changes}\end{aligned}$$

$$\begin{aligned}\mathit{with}: &\ \mathit{generated\ traffic\ GHG\ emissions}\\&= \mathit{generated\ \ GHG\ airport\ and\ flight\ emissions}\\&+ \mathit{generated\ hinterland\ GHG\ emissions}\end{aligned}$$

The ***generated traffic GHG emissions*** are the sum of *generated GHG airport and flight emissions* and *generated hinterland GHG emissions.*[23] The first step is to estimate generated demand, which is obtained from the EIB's CBA model.[24] GHG emissions from generated traffic are calculated by multiplying the generated demand (in number of passengers) by an emission factor. This emission factor includes scope 1, scope 2, LTO and cruise phases, all expressed in gCO_2e/passenger. To calculate the generated hinterland GHG emissions, generated traffic (in number of passengers) is multiplied by the average hinterland distance travelled to the airport per transport mode (the transport modes selectable are car and bus). This value is multiplied by an emission factor per transport mode in gCO_2e/pkm to calculate the generated hinterland GHG emissions.

[23] Hinterland emissions are those emissions that occur due to the transport of passenger to and from the airport, while generated hinterland emissions are those hinterland emissions that would not have happened without the new project (the baseline to compare against).
[24] The EIB's CBA for airports models the generated demand based on the generalised cost of travel and price elasticities of demand.

The ***surface access GHG emission changes*** are calculated using data from the EIB's CBA for airports. Firstly, the traffic to alternative airports being avoided due to transport distribution changes to/from the airport is estimated per transport mode in km (the transport modes selectable are car and bus). Then the distance is multiplied by an emission factor per transport mode in kg CO_2e/pkm to calculate the emission changes from surface access (surface access GHG emission changes).

In keeping with standard carbon footprinting methodology, the measure of relative emissions excludes the effects of any carbon offsetting schemes that may apply to the project. In the case of EIB aviation projects, the schemes that most commonly apply are the EU Emissions Trading Scheme (ETS) and the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA) of the United Nations. This means that a project where the ETS and/or the CORSIA may apply shows the same relative footprint measure as if neither the ETS nor the CORSIA applied. In this case, the resulting relative carbon footprint is therefore incompatible with the CBA.

Ports

Absolute GHG emissions

The EIB uses the following formula to calculate the average annual absolute GHG emissions for port projects:

$$\begin{gathered} Absolute\ GHG\ emissions = \\ Scope\ 1\ \&\ 2\ GHG\ emissions + Scope\ 3\ GHG\ emissions\ from\ manoeuvring\ and\ hotelling \end{gathered}$$

The ***scope 1 and 2 GHG emissions*** are calculated by multiplying the average additional traffic (the number of TEU for containers, tonnes, roll-on/roll-off (RORO) units or number of passengers) from a port project by an average GHG emission factor. The GHG emission factor is calculated based on available carbon footprints for scope 1 and 2 emissions of comparable facilities in the port (if available) or for comparable facilities in other ports (if publicly available).

The ***scope 3 GHG emissions from manoeuvring and hotelling*** are calculated by multiplying the average additional traffic by the average manoeuvring and hotelling emission factors.

Relative GHG emissions

The EIB uses the following formula for the calculation of average annual relative GHG emissions for ports:

$$\begin{gathered} Relative\ GHG\ emissions = \\ generated\ traffic\ GHG\ emissions + hinterland\ GHG\ emission\ changes \\ + shipping\ GHG\ emission\ changes + cargo\ handling\ GHG\ emission\ changes \end{gathered}$$

$$\begin{aligned} with: generated\ traffic\ GHG\ emissions \\ &= generated\ shipping\ GHG\ emissions + generated\ hinterland\ GHG\ emissions \\ &+ generated\ cargo\ handling\ GHG\ emissions\ (scope\ 1\ and\ 2\ GHG\ emissions) \end{aligned}$$

Handling GHG emission changes and generated cargo handling emissions are only taken into account if considered significant in the overall relative GHG emissions.[25]

[25] If significant in view of overall relative emissions.

The ***generated traffic GHG emissions*** are the sum of *generated shipping GHG emissions (including manoeuvring)*, *generated hinterland GHG emissions*[26] and *generated cargo handling (scope 1 and 2) GHG emissions* (if significant). To calculate these values, at first, the generated shipping demand needs to be obtained from the EIB's CBA model.[27] The generated shipping demand is measured in tonnes, TEU, RORO freight units or number of passengers and multiplied by a GHG emission factor in gCO_2e/TEU (or tonnes or number of passengers or RORO units) to calculate the generated shipping GHG emissions.[28] This calculation assumes an average shipping distance for the project traffic.

The generated shipping demand in tonnes, TEU, RORO freight units or number of passengers is combined with the estimated average hinterland distance travelled to the port per transport mode to estimate the total generated hinterland transport in tkm, TEUkm or pkm (the transport modes selectable are road, rail and inland waterway). This value is multiplied by a GHG emission factor in gCO_2e/tkm, gCO_2e/TEUkm or gCO_2/pkm to calculate the generated hinterland GHG emissions.

The ***hinterland GHG emission changes***[29] are calculated using data derived from the EIB's CBA for ports. Firstly, the traffic to alternative ports being avoided due to transport distribution changes to/from the port is estimated per transport mode in unitkm. Then, the traffic in unitkm is multiplied by a GHG emission factor in gCO_2e/unitkm per transport mode to calculate the GHG emissions from hinterland transport changes.

The ***shipping GHG emission changes*** are calculated using data derived from the EIB's CBA for ports. These changes are mentioned separately because they are not limited to the generated traffic. The impact of the project on the average GHG emission per tonne, TEU, RORO unit or passenger as a result of a scale increase or other efficiencies are thereby taken into account using different GHG emission factors for different average ship sizes calling at the project facilities in the with and without project scenarios.

The ***cargo handling GHG emission changes*** are calculated using project-specific data if the project leads to a significant change in cargo handling GHG emissions (e.g. when the project port terminal is operating significantly more efficiently or less carbon-intensively than the terminals in the without project scenario). As with shipping emissions, these changes are mentioned separately because they are not limited to the generated traffic.

[26] Generated hinterland emissions are emissions that occur due to the transport of generated traffic in the hinterland as a result of additional capacity and total transport cost reduction.
[27] The EIB's CBA for ports models the generated demand based on the generalised cost of transport and price elasticities of demand.
[28] It is important to note (as is also highlighted in the Word document on EIB's port methodology) that there is significant uncertainty regarding the different assumptions, meaning that the results for the generated traffic emissions are only order-of-magnitude estimates.
[29] Hinterland emission changes are the emissions saved by avoiding a traffic diversion as a result of additional project capacity.

ANNEX 6: CALCULATION OF CARBON FOOTPRINT FOR WASTEWATER TREATMENT FACILITIES

The calculation for the indirect emissions was done in the table using the EU average grid factor 245 gCO2/kWh. For a calculation in a specific country, please see the text below.

Wastewater treatment process	Carbon footprint wastewater treatment (CFWW) (t.CO2e/PE.y)	Indirect emissions (ID) (t.CO2e/PE.y)	Sludge disposal	Carbon footprint sludge disposal (CFSD) (t.CO2e/PE.y)	Total (t.CO2e/PE.y)
Septic tanks, IMHOFF tanks	0.091	0.0000	Landfill	0.194	0.285
			Septic sludge treatment plant	0.083	0.174
			Wastewater treatment plant	0.055	0.146
			Not specified	0.111	0.202
Primary treatment	0.039	0.0044	Landfill	0.067	0.110
			Land use without further treatment	0.045	0.088
			Composting	0.033	0.076
			Incineration	0.022	0.065
Primary treatment and anaerobic digestion	0.039	0.0024	Landfill	0.030	0.071
			Land use without further treatment	0.020	0.061
			Composting	0.015	0.056
			Incineration	0.010	0.051
Secondary treatment without anaerobic digestion	0.014	0.0134	Landfill	0.112	0.139
			Land use without further treatment	0.075	0.102
			Composting	0.056	0.083
			Incineration	0.037	0.064
Secondary treatment with anaerobic digestion	0.014	0.0073	Landfill	0.052	0.073
			Land use without further treatment	0.035	0.056
			Composting	0.026	0.047
			Incineration	0.017	0.038
Secondary treatment with enhanced anaerobic digestion	0.014	0.0064	Landfill	0.041	0.061
			Land use without further treatment	0.027	0.047
			Composting	0.020	0.040
			Incineration	0.013	0.033
Tertiary treatment (nitrogen, phosphorus removal) without anaerobic digestion	0.01	0.0156	Landfill	0.112	0.138
			Land use without further treatment	0.075	0.101
			Composting	0.056	0.082
			Incineration	0.037	0.063

Wastewater treatment process	Carbon footprint wastewater treatment (CFWW) (t.CO2e/PE.y)	Indirect emissions (ID) (t.CO2e/PE.y)	Sludge disposal	Carbon footprint sludge disposal (CFSD) (t.CO2e/PE.y)	Total (t.CO2e/PE.y)
Tertiary treatment (nitrogen, phosphorus removal) without anaerobic digestion	0.01	0.0086	Landfill	0.050	0.069
			Land use without further treatment	0.034	0.053
			Composting	0.025	0.044
			Incineration	0.017	0.036
Tertiary treatment (nitrogen, phosphorus removal) with enhanced anaerobic digestion	0.01	0.0075	Landfill	0.041	0.059
			Land use without further treatment	0.027	0.045
			Composting	0.020	0.038
			Incineration	0.013	0.031
Other processes					
Trickling filters, bio filters	0.017	0.0092	Landfill	0.112	0.138
			Land use without further treatment	0.075	0.101
			Composting	0.056	0.082
			Incineration	0.037	0.063
Carrousel (extended aeration)	0.015	0.0180	Landfill	0.056	0.089
			Land use without further treatment	0.037	0.070
			Composting	0.028	0.061
			Incineration	0.019	0.052
UASB (uplift anaerobic sludge blanket)	0.041	0.0110	Landfill	0.062	0.114
			Land use without further treatment	0.041	0.093
			Composting	0.031	0.083
			Incineration	0.021	0.073

How to use this table:

First, choose the process of your project and the expected sludge disposal. The carbon footprint is calculated as follows.

CF= (CFWW + ID + CFSD) x PE (population equivalent)

Where:

- CF is the carbon footprint of the project expressed in t CO_2e/year.
- CFWW is the CO_2e emitted per PE and per year in the wastewater treatment process (including CH_4 and N_2O).
- ID is the CO_2e indirect emissions produced by the consumed electricity per PE. The electricity was evaluated for every process, and for the emissions the grid factor used was the EU average of 245 gCO_2/kWh.
- ID can be increased or reduced proportionally to the grid factor of the country's project. For example, if the project is in a country with a grid factor of 442, then the ID has to be multiplied by the factor 442/245 = 1.80.
- CFSD is the CO_2e indirect emissions produced by the sewage sludge disposal and depends on the final destination of the sludge (landfill, land use, composting etc.).

GLOSSARY

Absolute (Ab) GHG emissions. Annual emissions estimated for an average year of operation.

Baseline (Be) GHG emissions. The project baseline emissions arise from the expected alternative scenario that reasonably represents the anthropogenic emissions by sources of GHGs that would have occurred in the absence of the project, estimated for an average year of operation.

Carbon footprint. A carbon footprint is the climate impact (GHG emissions) of a project.

Direct GHG emissions. Fugitive, combustion or chemical processes-related emissions from sources that are owned or controlled by the reporting company inside the project boundary. See scope 1 emissions.

Emissions. The release of GHGs into the atmosphere.

Emission factor. A factor allowing GHG emissions to be estimated from a unit of available activity data (e.g. tonnes of fuel consumed, tonnes of product produced) and gross GHG emissions.

Fugitive emissions. Emissions that are not physically controlled but result from the intentional or unintentional release of GHGs. They commonly arise from the production, processing, transmission, storage and use of fuels and other chemicals, often through joints, seals, packing, gaskets, etc.

Greenhouse gases (GHGs). GHGs are the seven gases listed in the Kyoto Protocol: carbon dioxide (CO_2); methane (CH_4); nitrous oxide (N_2O); hydrofluorocarbons (HFCs); perfluorocarbons (PFCs); sulphur hexafluoride (SF_6); and nitrogen trifluoride (NF_3).

Global warming potential (GWP). A factor describing the radiative forcing impact (degree of harm to the atmosphere) of one unit of a given GHG relative to one unit of CO_2 over a given period of time.

Indirect GHG emissions. Emissions that are a consequence of the operations of the project but occur at sources owned or controlled by another company (e.g. purchased electricity). See scope 2 and scope 3 emissions.

Process emissions. Emissions generated from manufacturing processes, such as the CO_2 that arises from the breakdown of calcium carbonate ($CaCO_3$) during cement manufacturing.

Project boundaries. The boundaries that determine the direct and indirect emissions associated with operations owned or controlled by the project. This assessment enables a project developer (investor) to establish which operations and sources cause direct and indirect emissions and decide which indirect emissions to include that are a consequence of the project operations.

Relative emissions. The difference (delta) between the absolute project emissions and the baseline scenario emissions.

Typical year of operation. In calculating the absolute or relative emissions of a project, a typical year of operation is used in which the project operates at normal capacity. This means excluding emissions from construction or decommissioning and unexpected outages and maintenance activities. In many cases, it is the average year over the lifetime of the project.

EIB Project Carbon Footprint Methodologies

Methodologies for the assessment of project greenhouse gas emissions and emission variations

Version 11.3

January 2023

European Investment Bank
The EU bank

European Investment Bank
98-100, boulevard Konrad Adenauer
L-2950 Luxembourg
+352 4379-22000
www.eib.org – info@eib.org