



Guidelines for the greenhouse gas calculation tool

for the pulp &
paper sector in Mexico

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Executive Summary

In August 2004, Mexico adopted the Greenhouse Gas Protocol Corporate Accounting and Reporting Standard, an internationally accepted standard to estimate corporate carbon dioxide and five other pollutant emissions that cause global warming, as the basis for a national corporate greenhouse gas reporting program. The GHG Protocol Accounting and Reporting Standard was developed by more than 500 experts from businesses, non-governmental organizations and governments. The GHG Protocol Standard has been adopted by more than 200 companies for reporting their GHG emissions and is used by both voluntary and mandatory GHG programs around the world as a framework for their program specifications and guidelines.

In order to undertake the Mexico GHG project, the Ministry of the Environment and Natural Resources (SEMARNAT), the World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD) formed an alliance known as the Mexico GHG Program (Pilot Program to Calculate and Report GHGs). The program seeks to help businesses prepare GHG inventories and identify opportunities to reduce them and participate in programs that lead to decreased emissions.

To further encourage and support reporting from one of the larger sectors in Mexico—the Pulp and Paper sector—SEMARNAT, WRI and the United States Environmental Protection Agency (EPA) signed an agreement with the United States – Mexico Foundation for Science (USMFS/FUMEC) to customize a GHG emissions calculation tool (i.e., guidance document and Excel worksheets) to the conditions of the Mexican pulp and paper sector. In addition, SO₂ was added as it is a significant pollutant for this sector and an important local pollutant in Mexico. A simplified emissions calculation tool for Mexico is expected to gain better acceptance among the Mexican pulp and paper industry and improve the consistency and accuracy in the measurement of source-specific emissions by local businesses and stakeholders.

The GHG accounting guidance follows the GHG Protocol Corporate Standard. The GHG calculation methodologies incorporated in this tool are based primarily on the guidance and worksheets developed for the pulp and paper sector by the National Council for Air and Stream Improvement, Inc. (NCASI)¹.

The greenhouse gases quantified by the tool customized for the pulp and paper sector in Mexico are CO₂, CH₄ and N₂O. As noted above, sulfur dioxide (SO₂) was also quantified given its dual importance as a local pollutant in Mexico and significance for the pulp and paper sector. Furthermore, though it is not directly considered a GHG, it does react with photochemical oxidants to produce sulfate aerosols that can modify climate.

The calculation tool provides guidance and Excel worksheets to help develop estimates of carbon dioxide (CO₂) emissions from stationary combustion sources based on the carbon content of fossil fuels used, the amount of these used and emission factors developed for the different types of fuels and the equipment that uses them. Carbon dioxide (CO₂) from burning biomass fuels are calculated and reported separately. In addition guidance and worksheets are provided to calculate methane and oxides of nitrogen emissions from combustion and other processes based on emission factors primarily from the IPCC. In the case of SO₂, emissions are reported separately and estimated based on fuel

¹ While the GHG methodologies included in this tool were developed based on the NCASI tool, NACASI is not to be held accountable for any errors etc. that may be found in the tool.

consumption, their sulfur content and emission factors developed in Mexico or calculated by the user.

This is the guidance document that accompanies the Excel worksheets designed to facilitate GHG emissions calculations discussed in this document.

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Acronyms

BNE: National Energy Balance

CHP: Combined Heat and Power (CHP) Systems

CEEE: Specific Electrical Power Consumption

CO₂: Carbon Dioxide

COA: Annual Operation Fact Sheet

CH₄: Methane

EF: Emissions Factor

GCV: Gross Heat Value

GDP: Gross Domestic Product

GHG: Greenhouse Gas

GWP: Global Warming Potential

HHV: Higher Heating Value

IPCC: International Panel for Climate Change

IPCC GP: International Panel for Climate Change Good Practice guidance

J: Joule

LHV: Low Heating Value

Mg: Mega Gram

N₂O: Nitrous Oxide

NCGs: Non-condensable Gases

NCV: Net Heat Value

PCC: Precipitated Calcium Carbonate

PEMEX: Petroleos Mexicanos

RETC: Emissions Registry and Transfer of Pollutants

SEMARNAT: Ministry of the Environment and Natural Resources

SO₂: Sulfur Dioxide

TJ: Tera Joule

U.S. EPA: United States Environmental Protection Agency

USMFS/FUMEC: US-Mexico Foundation for Science

WBSCD: World Business Council for Sustainable Development

WRI: World Resources Institute

1. Introduction

This tool, The Calculation Tool for the Pulp and Paper Sector in Mexico (Version 1.0), was customized by USMFS/FUMEC from the original version developed by the National Council for Air and Stream Improvement² in order to meeting the following conditions and needs of the Mexican Pulp and Paper sector:

- To be applicable to the common pulp and paper production processes in Mexico,
- To cover the GHG emission sources most commonly found in the pulp and paper sector in Mexico,
- To be compatible with GHG estimation guidelines set forth by the International Panel for Climate Change (IPCC),
- To be compatible with SEMARNAT GHG and SO₂ estimation and reporting guidelines, and
- To simplify, where possible, the NCASI tool while still providing a transparent, consistent and credible integrated air emissions quantification tool to estimate both GHG and criteria air pollutants (SO₂) emissions for various Mexican programs.
- Facilitate collection of climate relevant data and improve national data statistics for the sector

This calculation tool consists of this document and Excel worksheets to help users from the Pulp and Paper sector. The tool should be used in conjunction with the GHG Protocol Calculation and Reporting Corporate Standard, revised edition provided by WRI/WBCSD and available at:

<http://www.semarnat.gob.mx/spp/sppa/DOCUMENTOS/cclimatico/programa%20GEI%20Mexico/protocolodegei.pdf>

It is recommended that users consult the aforementioned document before using the tool where they will find a detailed description of the GHG calculation and reporting principles, and guidelines to establishing inventory boundaries and other issues related to estimating GHGs.

This tool builds on international best practices for estimating GHG and SO₂ from the pulp and paper sector and is intended to simplify reporting to different programs in Mexico – i.e., the Emissions Registry and Pollutant Transfer (RETC), or voluntary programs such as the Mexico GHG Program, as well as to help business identify and manage their risks related to GHG emissions.

² The original tool can be found on the GHG Protocol website, www.ghghprotocol.org, with information on how to contact the original authors of that tool. While the GHG methodologies included in this tool were developed based on the NCASI tool, NACASI is not to be held accountable for any errors etc. that might be found in the tool or for the SO₂ methodologies.

2. Pulp and Paper in Mexico

The pulp and paper sector in Mexico consists of 44 companies with 64 plants distributed throughout the country. Total production for 2003 was 334,600 tons of cellulose and 4,080,200 tons of paper, which amounts to 1.99% of the manufacturing contribution to the GDP (Gross Domestic Product) and generates 26,700 direct jobs. The different products manufactured by this sector include: cellulose pulp (3 companies), writing paper (9 companies), toilet and facial tissues (5 companies), cardboard (28 companies), and special papers (6 companies). Kraft is the most prevalent process in Mexican pulp plants and recycling of the chemicals utilized in this process is prevalent. Due to the great variety of paper products generated, it is not possible to focus on a single manufacturing process for paper (Annex 1 of this guidance document presents a general scheme of pulp and paper production). Pulp and paper plants are located in six states: Chihuahua, Durango, Jalisco, Michoacan, Oaxaca, and Veracruz. Paper plants are spread out in 16 states: Baja California, Chihuahua, Coahuila, Federal District (DF), Guanajuato, Jalisco, Mexico, Michoacan, Morelos, Nuevo Leon, Puebla, Queretaro, San Luis Potosi, Sonora, Tlaxcala, and Veracruz.

Pulp and paper is one of eleven manufacturing sectors required to submit a yearly Annual operation fact sheet (COA) (soon to change into the RETC), regarding each plant's atmospheric emissions. It is also one of the sectors that has entered with all of their members into the National Environmental Audit Program, a voluntary compliance assessment tool used by the authorities to encourage Mexican industry to work within environmental regulations and standards.

3. Customization of Calculation Tools for Estimating GHG and SO₂ Emissions from Mexican Pulp and Paper Mills

In order to use this tool, it is necessary to: 1) establish boundaries for the corporate inventory, 2) identify the type and quantity of fuel used, as well as fixed and mobile combustion sources that are at the facility, 3) the addition of chemicals to the process, and 4) identify the type of wastewater treatment process and 5) if the remaining biomass is burnt. Once the former has been established, it will be possible to estimate emissions of the following gases: CO₂, CH₄, N₂O and SO₂.

To develop a corporate inventory, e.g., for the Mexico GHG Program, this guidance document should be used in conjunction with:

- The Excel worksheets to calculate GHG and Mexican local pollutant emissions, and
- Greenhouse Gas Protocol – Corporate Calculation and Reporting Standard (revised edition),
- The program specifications of the program being applied to, if applicable.

If using this tool only to report GHG and SO₂ emissions to the RETC program, sections 6 through 12 of this guidance document should be used in conjunction with the Excel worksheets to calculate GHG and Mexican SO₂ emissions.

3.1 Objectives for Development of the Tool

In addition to the larger objectives defined above, the simplified, user-friendly air emissions quantification tool has been developed to contribute to additional objectives:

- To be consistent with national and international protocols for reporting GHG emissions.
- To insure credibility and transparency in estimating GHG emissions for pulp and paper mills.
- To provide companies the appropriate and easy to implement calculation methodologies representative of conditions that are generally found in pulp and paper mills in Mexico.
- To maximize comparability between companies nationally, and internationally.

3.2 Data Quality and its Relation to Inventory Objectives

The quantification methodologies described in this document can be used to develop estimations of emissions for a great number of purposes. Depending on the purpose of the emissions that are quantified, the quality of data applied in the calculations may differ. As the inventory has greater meaning for company objectives, the quality of the data used for its development must be greater. In Mexico for example, if the company objective is to prepare an inventory for the Emissions Registry and Pollutant Transfer (RETC) through the Annual Operation Fact Sheet (COA), the data should be as specific as possible to the processes, equipment and fuels used, since it is required information from high risk companies. On the other hand, if information is being collected for an internal benchmark inventory of a company's GHG emissions, the data need not be as precise and proxy/average data from similar processes may be used. Companies are encouraged to estimate emissions using company or facility specific activity data and emissions data where available. Use of this data will produce a higher quality inventory, more appropriate for future uses.

For most purposes, it is acceptable for companies to estimate GHG and SO₂ emissions using emission factors and corresponding "activity data" (e.g., amount of fuel consumed). For most mills, the largest sources of GHG and SO₂ emissions are fossil fuel-fired stationary combustion units. Fortunately, in most cases these emissions can be accurately estimated because facilities usually have excellent records of the types and amounts of fossil fuel being consumed, and CO₂ and SO₂ emissions from these sources are directly related to fuel carbon and sulfur content of the fuel, as reflected in widely accepted emission factors. For emission sources within the mill other than stationary combustion units, the quality of GHG emission estimates may be lower, due either to inadequate activity data, or emission factors based on insufficient data.

GHG inventories are reliant upon the quality of the emission factors used and activity data (as noted above). This guidance document includes a reporting template ([Annex 8](#)) that companies are encouraged to use to track the emission factors used in developing their inventory. This allows companies to be more transparent when presenting their calculations, and also allows for easier tracking of any adjustments to the inventory that may occur over time as emission factors are refined.

Companies may choose to use a less rigorous quantification methodology to estimate those GHG emissions in their inventory that are so small that they do not have a significant

impact on the total. Often this is done if there is a lack of data or the cost of gathering good data is very high. Some companies may also wish to exclude these emissions from their inventory, however if done so, they should be prepared to justify why those emissions were excluded to any outside stakeholder/GHG program/verifier that may be looking at the inventory. Before excluding any emissions from the inventory, companies should read the discussion on significant and minimum emissions that should be taken into consideration provided in detail in the original tool for the pulp and paper sector developed by NCASI (Section 7). In addition companies may want to read the sections on accounting principles (Chapter 1) and inventory quality (Chapter 7) in the GHG Corporate Standard for further guidance GHG Protocol WRI/WBCSD/SEMARNAT 2005.

It can be expected that many more emission measurements will be made in coming years which inform the development of improved emission factors will be developed reflecting these new data. Users of emissions inventory data need to understand this process and the resulting impact it will have on GHG and SO₂ inventory results. One can be certain that the quality of the estimates will improve over time, but it is impossible to forecast whether the estimates will be adjusted upward or downward in the process. The changes are expected to be relatively unimportant to the GHG profile of most mills, however, because the largest sources of GHGs and SO₂ from most pulp and paper mills, stationary fossil fuel combustion units, are well understood.

3.3 Units

The International Metric System is the official measuring system used in Mexico and thus it is used in this report; however, in the annexes other systems are used for emission factors and other parameters preferred by the authorities or countries responsible for their development.

3.3.1 Units of Measure for Greenhouse Gases

In Mexico, depending on the inventory objectives, GHGs can be reported as individual gases or in their CO₂ equivalents. For instance, when reporting GHGs for the RETC inventory, GHGs are reported as individual gases (CO₂, CH₄ and N₂O). On the other hand, in case of the inventory for the Mexican GHG Program they can be reported as their CO₂-equivalents. The Excel worksheets that come with this document allow the user to calculate GHGs independently or as their CO₂-equivalents.

Greenhouse gases are often compared on the basis of their estimated potential to cause global warming. Factors called Global Warming Potentials (GWPs) have been developed, and can be used to convert a quantity of non-CO₂ greenhouse gas into an amount of CO₂ with an equivalent warming potential. Although the derivation of these factors involves a large number of assumptions, GWPs are almost universally used to compare one greenhouse gas to another. The GWP for CH₄ is 21 so, from the standpoint of potential global warming, every gram of CH₄ is equivalent to 21 grams of CO₂. The GWP for N₂O is 310. When an emission estimate is the sum of several GHGs expressed as the equivalent amount of CO₂, the estimate is said to be in CO₂-equivalents, sometimes abbreviated as CO₂e, CO₂eq, or CO₂-equiv. To convert CO₂, CH₄, and N₂O emissions into CO₂-equivalents, multiply CH₄ emissions by 21 and N₂O emissions by 310, then add both to the corresponding CO₂ emissions.

SO₂, as mentioned earlier, is not a GHG, can not be converted into CO₂-equivalents and must be reported separately.

CO₂-equivalents are also sometimes reported as the weight of carbon in CO₂-equivalents, usually in metric tons of carbon equivalents (MTCEs). MTCEs are calculated by multiplying the weight (in tons, equal to 1000 kg) of CO₂-equivalents by 12/44, the weight fraction of carbon in carbon dioxide.

3.4 Steps Involved in Applying the Calculation Tool

In general terms, the calculation tools involve the user performing the following four steps:

- Determining the Objectives of the Inventory
- Identifying Boundaries
- Estimating Emissions
- Presenting Results

3.4.1 Determining the Objectives of the Inventory

In México, the pulp and paper companies that adopt the GHG Protocol can use it to:

- Prepare the inventory for the Emissions Registry and Pollutant Transfer (RETC) through the Annual Operation Fact Sheet (COA),
- Public reporting and participation in voluntary GHG programs, i.e., the Mexico GHG Program,
- Manage GHG risks and identify reduction opportunities,
- Participate in market-based mechanisms,
- Gain recognition for early voluntary action and good environmental stewardship.

If the user of this tool is calculating their GHG emissions for RETC only, some of the discussion about organizational boundaries (next section) will not be necessary since facility-level data is required and the facility is defined by the regulation.

However this tool can help the user quantify their GHG and SO₂ emissions for RETC and then guide the user to developing a corporate-level inventory that could be submitted to the Mexico GHG Program.

In order to develop a broader understanding of the risks and opportunities related to the GHG emissions from an entity, it is recommended to develop a corporate-level inventory in addition to collecting the RETC data.

3.4.2. Identifying Boundaries

There are two types of boundaries that must be considered in a GHG inventory: a) organizational boundaries and b) operational boundaries. Organizational boundaries reflect ownership or control of a company's operations and legal structure. Operational boundaries identify emission sources that need to be included in order to satisfy inventory objectives. The GHG Protocol provides extensive guidance regarding determination of

organizational and operational boundaries, which should be read to supplement the information in this guidance document.

3.4.3 Estimating Emissions

The next step is estimating GHG emissions. This calculation tool helps quantify:

- CO₂ emissions from stationary fossil fuel combustion,
- CH₄ and N₂O emissions from fossil fuel-fired units, recovery furnaces, biomass-fired boilers, and lime kilns,
- CO₂ emissions from make-up CaCO₃ or Na₂CO₃ used in pulp mills,
- CO₂, CH₄, and N₂O emissions from transportation and mobile sources (e.g., company-owned harvesting equipment and company-owned truck fleets),
- CH₄ emissions attributable to anaerobic waste treatment and sludge digestion operations,
- Fossil fuel-derived CO₂ exported to satellite precipitated calcium carbonate (PCC) plants,
- Imports of CO₂ (e.g., for pH neutralization),
- GHG emissions associated with power and steam that is purchased and consumed,
- GHG emissions attributable to power and steam exports, and
- SO₂ emissions (local pollutant for Mexico) from stationary fossil fuel combustion.

3.4.4 Presenting Results

The reporting templates provided in [Annex 8](#), emphasize the disaggregated and transparent presentation of results. The suggested format for reporting results provides the company with an opportunity to submit the following information.

- Consolidation methodology chosen (organizational boundary),
- Operations included within the operational boundaries of the inventory,
- Direct emissions,
- Indirect emissions from heat or power purchased and consumed,
- Emissions from burning biomass,
- Exports of power and steam,
- Optional other indirect emission sources,
- Emission factors used to develop the inventory,
- Quantification methodologies followed to develop the inventory.

4. Steps to apply the GHG emissions estimation methodology

Once the objectives of the inventory have been established (GHG report for voluntary and/or required programs), inventory boundaries are defined. As mentioned in section 3.5.2, inventory boundaries are divided into organizational and operational. The user will find in this section information on how to establish these boundaries.

4.1 Determining Inventory Organizational Boundaries

Organizational boundaries define the company for the purpose of calculating GHG and SO₂ (local pollutant for Mexico) emissions. There are a large number of possible ownership arrangements.

Where allocation of GHGs is specified contractually, it is to be used. Otherwise, the WRI/WBCSD GHG Protocol suggests that allocation be done in one of two ways: according to control—either financial or operational—or to equity share. Of course, if the reporting company fully owns all of the operations considered in the inventory, the organizational boundaries will be the same when determined by either approach. The GHG Protocol also outlines different selection criteria that will facilitate the choice of approach, including consistency with financial accounting ([WRI/WBCSD 2004](#)).

Companies developing a corporate inventory may encounter situations where the organizational boundary of the company include sources from which emissions will only be partly reported (or “consolidated”) as direct emissions at the corporate level, as they are from operations or companies jointly owned or controlled. In other cases (e.g., outsourced operations that are not owned or controlled) emissions might be reported fully as indirect. Some examples where one of these two cases may occur include:

- Combined heat and power operations where the mill is a partial owner of the generating facilities,
- Power islands that are owned, at least in part, by other corporate entities,
- Wastewater treatment operations owned or operated by third parties, and
- Mills where multiple parties share ownership of the facility.

It is recommended that companies review Chapter 3 of WRI/WBCSD’s Corporate Standard where more detailed information is found on the methods to establish organizational boundaries.

Note that organizational boundaries may not relate to any physical/site boundaries of a facility within the company, as companies may own facilities, or parts of facilities in locations all over Mexico. Likewise they may have operations on the physical site of one of their facilities, that they do not own or control, and that would therefore be outside their organizational boundaries. For this reason when identifying operational boundaries it is important to only look at the ownership of the process/ equipment/ operation, rather than at its location.

For consolidating corporate emissions; each company will have to decide between the three methods (control—financial or operation—or equity share), or to use more than one method to identify their organizational boundaries.

If using this tool for RETC, an environmental manager or individual responsible for developing the facility inventory to report emissions will need to define how to roll up their emissions to the facility rather than the corporate level. To do so, the reporter should read the RETC regulations for guidance on how a facility is defined for the RETC program.

4.2 Identification of Operational Boundaries and Central Operations to be included within the Inventory

Once the organizational boundaries of the company have been determined, emissions can be categorized into three groups: Scope 1 (direct emissions), Scope 2 (indirect emissions from the generation of purchased electricity consumed by the company) and Scope 3 (other indirect emissions), using the approach chosen under organizational boundaries (either ownership or control). These three scopes define the operational boundaries of the inventory.

The scope is not defined by the process causing the emission, but by the control or ownership of the process/equipment/operation causing the emissions based on the organizational boundaries that have been established for creating the inventory.

For example, the use of purchased power or steam, for processes by the reporting company, will be reported as Scope 2 since power comes from sources not owned or controlled by the company. However, if the power is generated at operations owned or controlled by the company, these emissions will fall within Scope 1 and no Scope 2 emissions are reported for their use.

Scope 1: Direct GHG Emissions and Local Pollutants for Mexico (SO₂).

Direct GHG emissions are from sources that are owned or controlled by the company, for example, emissions from combustion in owned or controlled boilers, furnaces, vehicles, and from chemical production in owned or controlled process equipment.

Direct CO₂ emissions from biomass combustion should not be included in Scope 1, but should be reported in a separate section as part of the inventory.

Sulfur dioxide (SO₂) emissions from stationary combustion sources are also considered direct, but since they are not GHGs, should also be reported separately from the three scopes mentioned above.

Scope 2: Indirect GHG Emissions from Purchased Electricity, Heat or Steam.

Scope 2 includes all estimates of GHG emissions from the electricity, heat or steam purchased and consumed by the company, but produced at facilities not owned or controlled by the company. Although the Scope 2 emissions physically occur at the facility where electricity, heat or steam is generated (and would be reported by that company as Scope 1), they are reported by the company who consumes the electricity, heat or steam as Scope 2, so that the company can keep track of reductions they are making through reducing their use of electricity, heat, and steam either through using more efficient equipment, better management, etc.

For the purposes of a GHG corporate inventory, such as would be developed for the Mexico GHG program, companies must report at least Scope 1 and 2 for the inventory to be considered valid.

Scope 3: Other Indirect GHG Emissions

Scope 3 is an optional reporting category that allows for the treatment of all other indirect emissions. Scope 3 emissions are a consequence of the activities by the company that occur from sources not owned or controlled by the company.

Some examples of Scope 3 activities are extraction and production of purchased materials, transportation of purchased fuels, and use of products and services sold to third parties.

Example of operations Includes within the different scopes

The tool has been developed anticipating that most companies devoted pulp and paper production will chose operational boundaries that include:

- Scope 1: Direct emissions from company central operations (boilers and furnaces that belong to the company)
- Scope 1: Direct emissions from operations outside of company property (company collection and transportation equipment)
- Scope 2: Indirect emissions related to purchasing and consuming electricity, heat or steam.
- Scope 3: All other indirect emissions (i.e., emissions from operations not owned or controlled) that are not related to importing electrical power (e.g., wastewater treatment) but may be important to track for management reasons.

[Annex 2](#) in this report includes Table A 2.1, which can be used to document operations included in the inventory. Companies may use other formats to summarize this information, but a description of inventory boundaries and operations can be very helpful in interpreting results and is highly recommended.

Examples of pulp and paper mill operations with the potential to emit greenhouse gases and SO₂ associated with Scope 1 include:

- Power boilers, gas turbines, and other combustion devices producing steam and/or electricity for the mill,
- Recovery furnaces and other devices burning spent pulping liquors,
- Incinerators,
- Lime kilns and calcination equipment,
- Gas or other fossil fuel-fired dryers (e.g., infrared dryers),
- Anaerobic wastewater treatment or sludge digestion operations (usually included only if owned by the company, or included in Scope 3 if operations are on the company's property),
- Landfills used to dispose of mill wastes (usually included only if owned by the company, or included in Scope 3 if operations are on the company's property),
- Owned vehicles and machinery, (or included in Scope 3 if operations are on the company's property),
- Harvesting equipment used to supply the mill (usually included only if owned by the company), and
- Trucks used to transport raw materials, products, or wastes for the mill (usually included only if owned by the company).

Examples of pulp and paper mill operations that may be associated with Scope 2, because they sometimes consume purchased power or steam include:

- Preparing virgin fiber (debarking, chipping, and other wood yard operations, usually included only if owned by the company),
- Preparing recovered fiber, including de-inking,
- Mechanical pulping,
- Chemical pulping,
- Semi-chemical pulping,
- Other chemical pulping processes,
- Chemical recovery operations,
- Pulp screening, thickening, and washing,
- Virgin fiber bleaching and recovered fiber bleaching and brightening,
- On-site production of chlorine dioxide and other bleaching chemicals,
- Paper and paperboard production, including stock cleaning and refining,
- Coating, including extrusion coating,
- Trimming, roll wrapping, sheet cutting, etc.,
- Normal office and building operations for mill employees,
- Equipment for incoming process water and wastewater treatment, and
- Non-fossil fuel-fired emission control devices (e.g., ESPs, biofilters).

Examples of some operations of pulp and paper mills that most likely can be associated to GHG emissions within Scope 3 include:

- Transportation of plant employees to their work place (public transportation or private automobiles),
- Business trips by executives, employees or sales representatives, and
- Use of purchased products and services,
- Source of emissions that are on a facility's site, but not Scope 1 by control or equity definitions.

5. GHG emissions from fuel consumption

This section is focused on guiding the user in estimating GHG and SO₂ emissions based on fuel consumption and their heat value.

Often, fuel consumption is given physical units (barrels, cubic meters, tons, etc.). In order to convert fuel consumption from physical to energy units, it is necessary to know the heating capacity*¹ of fuels. In Mexico, the Ministry of Energy annually publishes the heating capacity of Mexican fuels. [Annex 3](#) (Table A3) provides net heating capacities for fuels used in Mexico.

If companies require heat capacity values for fuels in other countries, the Revised 1996 IPCC Guidelines suggests values for different regions or Equation 1 can be used to calculate it.

Calculation of heat content of fuel consumed

$$A_{f,h} = A_{f,v}H_v \text{ or } A_{f,h} = A_{f,m}H_m \text{ ----- (equation 1)}$$

Where*²,

- $A_{f,h}$ = Heat content of fuel consumed (GJ or million Btu)
- $A_{f,v}$ = Volume of fuel consumed (e.g., L, gallons, ft³, m³)
- $A_{f,m}$ = Mass of fuel consumed (e.g., short tons or metric tons)
- H_v = Calorific value (i.e., heat content) of fuel on a volume basis (e.g., million Btu/ft³ or GJ/L)
- H_m = Calorific value (i.e., heat content) of fuel on a mass basis (e.g., million Btu/short ton or GJ/metric ton)

*¹ Heat value of a fuel is a basic requirement for estimating GHG and SO₂ emissions, and can be used to establish the efficiency of said fuel for heat production (IPCC, 1996).

*² All units need to correspond to the same system of measurements.

Companies can use data from one of the following sources, with the preferred sources listed first:

- data on the specific fuels being used at the mill,
- the most appropriate data recommended by national authorities, and
- the most appropriate data available from other sources, such as the IPCC.

5.1 Emissions from Stationary Biomass Fuel Combustion

Many pulp and paper mills generate more than half their energy needs from biomass fuels recovered from the industry's waste and process streams. When these biomass fuels are burned—wood chips, bark, sawdust, and pulping liquors recovered from the harvesting and manufacturing processes—the CO₂ emitted during the combustion processes is the atmospheric carbon dioxide that was sequestered during growth of the tree; hence, there is no net contribution to the atmospheric CO₂ level. This carbon cycle is a closed loop. New tree growth keeps absorbing atmospheric carbon dioxide and maintains the cycle. The IPCC has stated that CO₂ emissions from burning biomass do not add to atmospheric concentrations of carbon dioxide ([IPCC 1997a, c](#)) and this accounting convention is also followed by the United Nations Framework Convention on Climate Change national inventory efforts, though biomass that has been combusted is recorded as additional information.

Following this IPCC convention, the GHG Protocol also requires that biomass-derived CO₂ be reported as additional information. Therefore, in keeping with well-established practices, the GHG inventory results generated using this calculation tool do not include CO₂ emissions from biomass burning, but methods are provided for estimating biomass-derived CO₂ so that it can be reported where needed.

IPCC provides a list of biomass fuels ([IPCC 1997a, c](#)):

- Wood and wood residuals (although biogas from wood residuals and other biomass is not specifically listed by IPCC, it clearly falls within the general definition of biomass)
- Charcoal
- Dung
- Agricultural residues and wastes

- Municipal and industrial wastes, where the organic material is biological in origin (this would include wastewater treatment sludge from pulp and paper mills)
- Waste pulp
- Bio-alcohol
- Black liquor
- Landfill gas
- Sludge gas

CO₂ emissions from peat burning are usually considered to be GHGs and are included in the emissions from fossil fuel burning.

Non-condensable gases (NCGs) consist of reduced sulfur compounds and other organic compounds that are formed during the Kraft pulping process. These gases are often collected and burned in boilers, lime kilns, or incinerators as a pollution abatement procedure. Because the carbon in NCGs originated in wood, the CO₂ generated during combustion of NCGs is of biomass origin and is, therefore, not included in a tabulation of direct GHG emissions. The quantities of NCGs combusted at Kraft mills are very low relative to quantities of spent pulping liquors and other wood residuals fuels, but when reported also fall in the additional information category with other combusted biomass. There are limited data on methane or nitrous oxide generation from combustion of NCGs and these emissions are generally not included in the inventory.

5.1.1 Methane and Nitrous Oxide from Burning Biomass Fuels

Although CO₂ from biomass burning is almost universally excluded from GHG inventories—except as an additional category—CH₄ and N₂O from biomass burning are sometimes included because these gases do not participate in the atmospheric CO₂ sequestration-recycling process explained in the last section. Therefore, quantification methodologies are provided to assist in estimating these emissions.

If a company has reliable site-specific data allowing it to estimate CH₄ and N₂O emissions from biomass combustion, it should use those data. Otherwise, it will be necessary to use the most appropriate emission factors available. Unfortunately, there are few data on CH₄ and N₂O emissions from biomass combustion.

[Annex 4](#)³ provides a summary of information available on methane and nitrous oxide emissions from biomass boilers. The variability in the data reflects the many different types and ages of boilers tested, operating conditions, control equipment, and fuel characteristics. As discussed in the previous section there are no data on methane or nitrous oxide emissions from combustion of NCGs generated during the Kraft pulping process.

5.1.2 Combination Fuel-Fired Boilers Burning Biomass and Fossil Fuel

Methane and nitrous oxide releases from boilers are sensitive to combustion conditions, especially combustion temperature. In most cases, combustion conditions in combination fuel boilers are more like those in biomass-fired boilers than fossil fuel-fired boilers. Often,

³ Annex 4 is a summary of NCASI information and of the work that has been developed with the companies that make it up.

methane and nitrous oxide emissions are more directly related to combustion conditions than to fuel type. Because of the high moisture content of most wood-based fuels, a reasonable default is to assume that combustion conditions in combination fuel-fired boilers reflect the impact of wood wastes. Therefore, unless data are available from site-specific testing on similar boilers burning a comparable mix of fuels, or unless combustion conditions in the combination fuel-fired boiler are more like fossil fuel-fired boilers than wood residual fuel boilers, it is recommended that emissions from combination fuel-fired boilers be estimated from the total heat input to the boiler and CH₄ and N₂O emission factors for biomass.

In some cases, a facility may operate a combination fuel boiler where fossil fuel comprises a major portion of the total fuel to the boiler. Although, estimating CH₄ and N₂O emissions using the approach outlined in the previous paragraph is appropriate in these cases, it is also valid to estimate these emissions based on consumption rates of each fossil fuel multiplied by the fuel's emission factors, plus the consumption rate of biomass fuel multiplied by the biomass fuel's emission factors.

Example Calculation: Pulp and Paper Mill with Bark Boiler

A pulp and paper mill operates a circulating fluidized bed (CFB) bark boiler that produces 250,000 kg/hr (550,000 lb/hr) of steam. In a year, the boiler burns approximately 6.9×10^6 GJ of bark and 0.8×10^6 GJ of residual fuel oil. Because the boiler receives supplemental fossil fuel, it is necessary to estimate CO₂ generation from fossil fuel use and CH₄ and N₂O emissions based on total firing rate. The mill decides to use the IPCC emission factor for residual fuel oil (76.6 t CO₂/TJ, after correcting for 1% un-oxidized carbon) and to estimate CH₄ and N₂O emissions based on total firing rate and factors developed by Fortum on CFB boilers. The average emission factor found by Fortum, shown in Table A 4.5 from [Annex 4](#), is 1 kg CH₄/TJ and 8.8 kg N₂O/TJ.

CO₂ emissions from fossil fuel:

- $(0.8 \times 10^6 \text{ GJ/yr}) = (0.8 \times 10^3 \text{ TJ/yr})$
- $(0.8 \times 10^3 \text{ TJ/yr}) \times (76.6 \text{ t CO}_2/\text{TJ}) = 61,300 \text{ t CO}_2/\text{yr}$

CH₄ emissions:

- Total heat input = $(6.9 \times 10^6 \text{ GJ/yr}) + (0.8 \times 10^6 \text{ GJ/yr}) = 7.7 \times 10^6 \text{ GJ/yr} = 7.7 \times 10^3 \text{ TJ/yr}$
 - $7.7 \times 10^3 \text{ TJ/yr} \times 1 \text{ kg CH}_4/\text{TJ} = 7,700 \text{ kg CH}_4/\text{yr} = 7.7 \text{ t CH}_4/\text{yr}$
- Using the IPCC warming potential of 21, this is equal to 162 t CO₂eq/yr.

N₂O emissions:

- Total heat input = $7.7 \times 10^3 \text{ TJ/yr}$
 - $7.7 \times 10^3 \text{ TJ/yr} \times 8.8 \text{ kg N}_2\text{O}/\text{TJ} = 67,800 \text{ kg N}_2\text{O}/\text{yr} = 67.8 \text{ t N}_2\text{O}/\text{yr}$
- Using the IPCC warming potential of 310, this is equal to 21,000 t CO₂eq/yr

Total CO₂ equivalents emitted = 61,300 + 162 + 21,000 = 82,500 t CO₂eq/yr

5.2 Carbon Dioxide (CO₂) Emissions from Stationary Fossil Fuel Combustion

Carbon dioxide emissions from stationary fossil fuel combustion represent the majority of GHG emissions for most pulp and paper mills. Carbon dioxide (CO₂) emissions are estimated from the carbon content of, or emission factors for, all fossil fuels being burned. In some cases, a correction (i.e., a reduction) is made for un-oxidized carbon. The following equation may be used:

Calculation based method for CO₂ emissions

$$E = A_{f,v} \cdot F_{c,v} \cdot F_{ox} \cdot \left(\frac{44}{12}\right) \text{ or } E = A_{f,m} \cdot F_{c,m} \cdot F_{ox} \cdot \left(\frac{44}{12}\right) \text{ or } E = A_{f,h} \cdot F_{c,h} \cdot F_{ox} \cdot \left(\frac{44}{12}\right)$$

(equation 2)

Where,

E = Mass emissions of CO₂ (short tons or metric tons)

A_{f,v} = Volume of fuel consumed (e.g., L, gallons, ft³, m³)

A_{f,m} = Mass of fuel consumed (e.g., short tons or metric tons)

A_{f,h} = Heat content of fuel consumed (GJ or million Btu)

F_{c,v} = Carbon content of fuel on a volume basis (e.g., short tons C/gallon or metric tons C/m³)

F_{c,m} = Carbon content of fuel on a mass basis (e.g., short tons C/short ton or metric tons C/metric ton)

F_{c,h} = Carbon content of fuel on a heating value basis (e.g., short tons C/million Btu or metric tons C/GJ)

F_{ox} = Oxidation factor to account for fraction of carbon in fuel that remains as soot or ash

(44/12) = The ratio of the molecular weight of CO₂ to that of carbon

Note: Activity data and carbon content factors should be in the same basis (i.e., volume, mass, or energy). For gaseous fuel quantities in terms of volume, care should be taken to ensure all data are on a consistent temperature and pressure basis.

EFs (emission factors) and the carbon content of fossil fuels and unburned carbon in Mexico, are not easily available in a database or consolidated format. However, PEMEX and fuel vendors can supply the characteristics (e.g., carbon content) of the products they sell. If provided, these emission factors are likely to be more accurate for calculating CO₂ as they represent more fuel specific information. If such emission factors are not available and there are no sources for more specific information that would justify the use of a different EF then default EFs from IPCC can be used and are provided in [Annex 5](#) - Table A 5.1.

To correct CO₂ emission estimates for un-oxidized carbon⁴, IPCC recommends default correction factors of 0.98 for coal, 0.99 for oil and oil products, 0.995 for gas, and 0.99 for peat (non-household use combustion) ([IPCC 1997c](#)). The IPCC emission factors in Table A 5.1 from [Annex 4](#) are presented uncorrected and corrected for un-oxidized carbon based on these recommendations. IPCC points out, however, that in the case of coal, un-

⁴ The correction is made because a small fraction of the carbon in the fuel can escape oxidation and remain as a solid after combustion in the form of soot or ash

oxidized carbon can be much higher than default values and cites an Australian study of coal-fired boilers where un-oxidized carbon ranged from 1% to 12% of the carbon fed to the boiler. Unfortunately, there is not a consensus among different GHG accounting and reporting protocols with respect to the most appropriate correction factors for un-oxidized carbon, as illustrated by the information in Table A 5.2 from [Annex 5](#). Unless stated otherwise, the factors and example calculations presented in this guidance document incorporate corrections for un-oxidized carbon based on IPCC recommendations.

In many cases, total CO₂ emissions from all sources burning a single fossil fuel at a manufacturing facility can be estimated without considering emissions from each combustion unit separately. For instance, if a mill is burning natural gas in several boilers and infrared dryers, CO₂ emissions from natural gas burning can be estimated from total gas used. In fact, some mills may lack fuel metering devices that would be required to estimate emissions from each combustion unit separately. However, whether or not this approach can be utilized also depends on the purpose of the data. For example, the RETC requires that emissions from each combustion unit be estimated separately and, in the Mexican GHG Program, estimations for combustion units can be made separately or combined.

For more detailed guidance on estimating GHG emissions from stationary combustion sources, the user may also wish to reference the WRI/WBCSD Stationary Combustion Tool directly (see www.ghgprotocol.org).

5.3 Methane and Nitrous Oxide Emissions from Stationary Fossil Fuel Combustion

Methane and nitrous oxide emissions from fossil fuel combustion are usually very small compared to CO₂ emissions. Indeed, some GHG programs do not address CH₄ and N₂O from fossil fuel combustion. However, because both the Mexico GHG Program and RETC require CH₄ and N₂O to be included, they are addressed in this calculation tool.

Emissions of these gases from stationary combustion sources depend upon fuel characteristics, size and vintage of the equipment, type of combustion technology, pollution control equipment, and ambient environmental conditions. Emissions also vary with operation and maintenance practices.

Fuel characteristics (e.g., heating value), the type of technology (e.g., combustion, operating and maintenance regime, size and vintage of equipment), and emission controls, are major factors determining rates of CH₄ and N₂O gas emissions from stationary sources. Specifically, N₂O emissions are closely related to air-fuel mixes and combustion temperatures, as well as the composition and operating temperature of any catalytic emission control equipment employed. Methane emissions from stationary combustion are primarily a function of the CH₄ content of the fuel and combustion efficiency.

Given their dependence on specific combustion conditions and other characteristics, the preferred approach for estimating CH₄ and N₂O emissions is to use a method based on combustion unit-specific data (see [Annex 5](#) Table A 5-3 and Equation 3). The preferred method generally calls for the use of detailed activity data and emission factors that account for these characteristics.

$$E = A * FE * \left(1 - \frac{C}{100}\right) \text{----- (Equation 3)}$$

Where:

E = Emissions (kg)

A = Activity level (e.g., GJ of fuel burned)

FE = Emission factor (kg of pollutant/GJ of fuel burned)

C = Control efficiency/utilization of any emission control equipment (percent)

It is prudent to recognize that the intended purpose of emissions inventories may influence the required level of resolution of these estimates, and thus the required specificity of the emission factors used (i.e., an inventory developed for internal company use may not require the same accuracy and resolution as an inventory developed for participation in an emissions trading program).

Most national authorities⁵ publish factors for estimating emissions of CH₄ and N₂O from fossil fuel-fired boilers and other combustion devices. IPCC provides Tier 1 and Tier 2⁶ emission factors for methane and nitrous oxide (see [Annex 5](#) Tables A 5.4 and A 5.5, respectively). Tier 1 is a method for estimating emissions described by IPCC as one in which emissions from all combustion sources (of a particular fuel) are estimated based on the (total) quantity of fuel consumed and default emission factors (IPCC 1997b,c). IPCC describes the Tier 2 method as one in which emission estimates are based on detailed fuel and technology information. In other words, a Tier 1 analysis could be performed based on facility-level fuel consumption data, whereas a Tier 2 analysis would require source by source fuel consumption data and associated source-specific emission factors.

As an example of a Tier 1 approach, a mill burning natural gas in one boiler, one dryer, and one RTO estimates emissions by summing the total natural gas used in these three devices and multiplies this quantity by an emission factor for natural gas. An example of a Tier 2 approach for the same facility would be to estimate emissions from the boiler by multiplying boiler fuel consumption by an emission factor developed specifically for that type of boiler, estimate emissions from the dryer using specific fuel consumption data and an emission factor developed for that type of dryer, and so on. The Tier 2 method is more detailed than the Tier 1 method, and if source-specific fuel consumption data and emission factors are available, the Tier 2 method may return more accurate results than the Tier 1 method.

IPCC's Tier 1 emission factors for methane and nitrous oxide are presented in [Annex 5](#), Table A 5.4. IPCC's Tier 2 emission factors, shown in Annex 4, Table A 5.5 for many fossil fuels and combustion devices of interest to the forest products industry, are usually preferred because they are more specific to fuel type and combustion device.

⁵ Currently, no national factors have been published for Mexico, but some facilities may have access to factors from source testing.

⁶ Level 1 method is based on estimating emissions from the total amount of fuel used with average EFs. Level 2 is based on detailed fuel consumption and the type of combustion equipment technology. The second method is more detailed than the first and if detailed fuel consumption data and specific EFs for the type of combustion equipment are available, it should be used since it provides more precise results

5.3.1 Summary of Guidelines for Estimating Methane and Nitrous Oxide Emissions

Based on the information in Section 5.2, the following general guidelines are provided for estimating methane and nitrous oxide emissions.

- If the company has access to facility-level fuel consumption data only, this activity data can be used in conjunction with the factors from [Annex 5](#), Table 5.5 to estimate emissions.
- If the facility has access to combustion device-specific fuel consumption data, this activity data can be used with the appropriate (source-specific) emission factors from Table A 5.5, and with those from Table A 5.4 for combustion devices for which no factors are available in Table A 5.5 (e.g., gas-fired dryers, RTOs) to estimate emissions.
- If the facility has access to methane emissions data from source testing of devices such as natural gas-fired dryers and RTOs/RCOs, it can be used to adjust estimates derived from emission factors and fuel consumption (activity) data.

Example Calculation: CO₂, CH₄, and N₂O emissions from natural gas use at a small mill

A mill uses natural gas in a small boiler and in several infrared dryers. The mill's records indicate that over a year's time, it used 17 million standard cubic meters of natural gas. The mill decides to estimate the emissions from overall natural gas consumption instead of attempting to separate boiler emissions from the infrared dryer emissions. The mill does not know the carbon content of its gas supply, but the IPCC emission factor is 55.9 metric tons CO₂/TJ (after correcting for 0.5% un-oxidized carbon). The mill uses the CH₄ and N₂O emission factors from Table A. 4.5 in [Annex 4](#) (5 kg CH₄/TJ and 0.1 kg N₂O/TJ). The mill estimates the heating value of natural gas to be 52 TJ/kiloton and the density to be 0.673 kg/standard cubic meter. Annual emissions are calculated as follows.

CO₂ emissions:

- $(17 \times 10^6 \text{ m}^3 \text{ gas/yr}) \times (0.673 \text{ kg/m}^3) = 11.4 \times 10^6 \text{ kg gas/yr} = 11.4 \text{ kton gas/yr}$
- $(11.4 \text{ kton gas/yr}) \times (52 \text{ TJ/kton}) = 595 \text{ TJ/yr}$
- $(595 \text{ TJ/yr}) \times (55.9 \text{ t CO}_2/\text{TJ}) = 33,300 \text{ ton CO}_2/\text{yr}$

CH₄ emissions

- $(595 \text{ TJ NCV/yr}) \times (5 \text{ kg CH}_4/\text{TJ NCV}) = 2975 \text{ kg CH}_4/\text{yr} = 2.975 \text{ ton CH}_4/\text{yr}$
- Using the IPCC GWP of 21, this is equal to 62.5 ton CO₂eq/yr

N₂O emissions

- $(595 \text{ TJ NCV/yr}) \times (0.1 \text{ kg N}_2\text{O}/\text{TJ NCV}) = 59.5 \text{ kg N}_2\text{O}/\text{yr} = 0.06 \text{ ton N}_2\text{O}/\text{yr}$
- Using the IPCC GWP of 310, this is equal to 18 ton CO₂eq/yr

Total GHG emissions = 33,300 + 62.5 + 18 = 33,400 ton CO₂eq/yr

On a CO₂-equivalents basis, CH₄ and N₂O emissions are approximately 0.25% of CO₂ emissions. These emissions may be very small even if the emission factors are several times larger. Depending on the use of the inventory and/or the program specifications for

which the inventory is being developed, these emissions may not be material to the results of the inventory because they are less than 0.25% of CO₂ emissions.

Example Calculation: CO₂, CH₄, and N₂O emissions from a large dry-bottom, wall fired boiler burning pulverized bituminous coal.

Case 1: CO₂ emissions based on carbon content of fuel

The boiler produces 350,000 kg steam per hour (about 770,000 lb/hr). Over a year's time, the mill's records indicate that the boiler consumed 336,000 Mg (370,000 short tons) of coal, having a higher heating value, on average, of 13,000 Btu HHV/lb.

The mill has information on the carbon content of the coal being burned in the boiler (80.1% carbon, by weight). The mill decides that the default IPCC correction for unburned carbon in coal-fired boilers (2% unburned carbon) is appropriate. The mill decides to use the Tier 2 IPCC emission factors for CH₄ and N₂O from Table A 4.5 in Annex 4. The emission factors from Table A 4.5 for dry bottom, wall fired boilers burning pulverized bituminous coal are 0.7 kg CH₄/TJ NCV and 1.6 kg N₂O/TJ NCV. The mill applies the usual assumption that the NCV (or LHV) for coal is 5% lower than the GCV (or HHV). The annual emissions of CO₂, CH₄, and N₂O are estimated as follows:

CO₂ emissions:

• $(336,000 \text{ Mg/yr coal}) \times (0.801 \text{ Mg carbon / Mg coal}) \times (0.98 \text{ Mg carbon burned}) \times (44 \text{ Mg CO}_2 / 12 \text{ Mg carbon}) = 967,000 \text{ Mg CO}_2/\text{yr}$ or $967 \times 10^3 \text{ ton CO}_2/\text{yr}$

CH₄ emissions:

• $370,000 \text{ short tons coal/yr} = 740 \times 10^6 \text{ lb/yr}$
• $(740 \times 10^6 \text{ lb/yr}) \times (13,000 \text{ Btu HHV/lb}) = 9.62 \times 10^{12} \text{ Btu HHV/yr}$
• for coal, LHV is 0.95 times HHV
• $(9.62 \times 10^{12} \text{ Btu HHV/yr}) \times (0.95 \text{ to correct to LHV}) = 9.14 \times 10^{12} \text{ Btu LHV/yr}$
• $(9.14 \times 10^{12} \text{ Btu LHV/yr}) \times (1055 \text{ J/Btu}) = 9.64 \times 10^{15} \text{ J NCV/yr} = 9.64 \times 10^3 \text{ TJ NCV/yr}$
• $\text{CH}_4 \text{ emissions} = (9.64 \times 10^3 \text{ TJ NCV/yr}) \times (0.7 \text{ kg CH}_4/\text{TJ NCV}) = 6.75 \times 10^3 \text{ kg CH}_4/\text{yr}$
or $6.75 \text{ t CH}_4/\text{yr}$

Using the IPCC GWP of 21 for CH₄, this equates to 142 t CO₂eq/yr

N₂O emissions:

• $\text{N}_2\text{O emissions} = (9.64 \times 10^3 \text{ TJ NCV/yr}) \times (1.6 \text{ kg N}_2\text{O}/\text{TJ NCV}) = 15.4 \text{ t N}_2\text{O/yr}$
Using the IPCC GWP of 310 for N₂O, is to 4,780 ton CO₂eq/yr

Total GHG emissions = $967,000 + 142 + 4,780 = 972,000 \text{ ton CO}_2\text{-equivalents/yr}$
Compared to CO₂, CH₄ and N₂O emissions from this boiler are very small.

CO₂ emissions = 967,000 ton CO₂/yr

CH₄ emissions = 142 ton CO₂eq/yr or 0.015% of CO₂ emissions

N₂O emissions = 4,780 ton CO₂-eq./yr or about 0.5% of CO₂ emissions

Example Calculation: CO₂, CH₄ and N₂O emissions from a large dry-bottom, wall fired boiler burning pulverized bituminous coal.

Case 2: CO₂ emissions based on emission factors

The boiler has the same characteristics: it produces 350,000 kg steam per hour (about 770,000 lb/hr). Over a year's time, the mill's records indicate that the boiler consumed 336,000 Mg (370,000 short tons) of coal having a higher heating value, on average, of 13,000 Btu HHV/lb.

In this case the mill does not have information on the carbon content of the coal being burned in the boiler. The IPCC default emission factor from Table A 4.4 (Tier 1) for CO₂ is 94.6 ton CO₂/TJ NCV. The mill decides that the default IPCC correction for unburned carbon in coal-fired boilers (2% unburned carbon) is appropriate.

CO₂ emissions:

- 370,000 short tons coal/yr = 740×10^6 lb/yr
- $(740 \times 10^6 \text{ lb/yr}) \times (13,000 \text{ Btu HHV/lb}) = 9.62 \times 10^{12}$ Btu HHV/yr
- for coal, LHV is 0.95 times HHV
- $(9.62 \times 10^{12} \text{ Btu HHV/yr}) \times (0.95 \text{ to correct to LHV}) = 9.14 \times 10^{12}$ Btu LHV/yr
- $(9.14 \times 10^{12} \text{ Btu LHV/yr}) \times (1055 \text{ J/Btu}) = 9.64 \times 10^{15}$ J NCV/yr = 9.64×10^3 TJ NCV/yr
- uncorrected CO₂ emissions = $(9.64 \times 10^3 \text{ TJ NCV/yr}) \times (94.6 \text{ t CO}_2 / \text{TJ NCV}) = 912 \times 10^3$ ton CO₂/yr
- CO₂ emissions corrected for 2% unburned carbon = 894×10^3 ton CO₂/yr

Methane and nitrous oxide emissions are calculated as in **Case 1**.

CO₂ emissions = 894,000 t CO₂/yr

CH₄ emissions = 142 ton CO₂eq/yr or 0.016% of CO₂ emissions

N₂O emissions = 4,780 ton CO₂eq/yr or about 0.5% of CO₂ emissions

As in the previous example, this comparison suggests that it may be relatively simple for many mills to document that emissions of CH₄ and N₂O from fossil fuel-fired boilers are not material to the results of their inventory.

5.4 Sulfur Dioxide (SO₂) Emissions from Stationary Fossil Fuel Combustion: local pollutant for Mexico

Sulfur dioxide is not a GHG, but is considered an important pollutant generated by Mexican industry and required by the RETC through the COA (Annual Operation Fact-sheet), thereby included in this tool. SO₂ emissions depend on fuel characteristics and not combustion technologies. SO₂ emissions from stationary sources can be calculated based on the methodology (Equation 4) presented in the Mexican Official Standard, NOM-085-SEMARNAT-1994, for stationary sources that use fossil fuels, either solid, liquid or gas and estimates emissions based on monthly consumption of these sources and sulfur content certified by the supplier, or can also be calculated based on the IPCC methodology that is very similar to the previous one, but also considers emission control equipment efficiencies and the sulfur content trapped in the ash. The Mexican Official Standard methodology is presented as follows:

$$E_{SO_2} = (NA)(FE_{SO_2}) \text{ ----- (Equation 4)}$$

Where:

E_{SO_2} = SO₂ Emissions

NA = Amount of fuel burned within a specified time period

FE_{SO_2} = Emission Factor specific for the type of fuel, according to [Annex 5](#), Tables A 5.6 and A 5.7.

Since the sulfur content of natural gas is expressed in g/m³, and not as a percentage, SO₂ emissions for natural gas must be calculated by means of the same procedure, but taking into account the difference in units.

For the fuels not considered in this table, the emission factor should be calculated according to Equation 5.

$$Emission\ Factor = \frac{\frac{\%S}{100} \left[\frac{KgS}{Kg\ of\ Fuel} \right] * 2 \left[\frac{KgSO_2}{KgS} \right]}{Heating\ value \left[\frac{10^6\ kcal}{kg\ of\ Fuel} \right]} = \left[\frac{KgSO_2}{10^6\ kcal} \right] \text{ (Equation 5)}$$

Where:

% S= weight percentage of sulfur in the fuel

If fuel characteristics data are not available, NOM-086-SEMARNAT-1994 ([Annex 5](#), Table 5.8), has sulfur content specifications for fuels that can be used as default values.

The IPCC methodology, as mentioned earlier, is very similar to the previous and consists of five steps:

1. Calculation of the sulfur content of each fuel (expressed as a percentage, with the exception of natural gas. For the latter, it must be expressed in g/m³),
2. Estimation of sulfur retention in ash,
3. Estimation of control technology efficiencies, and
4. Calculation of emissions according to Equation 6.

$$E_{SO_2} = A * \left(\frac{FE}{1000} \right) \text{ ----- (Equation 6)}$$

The EF is obtained with Equation 7:

$$FE_{SO_2} = 2 \times \left(\frac{\% S}{100} \right) \times \frac{1}{Q} \times 10^6 \times \left(\frac{100 - r}{100} \right) \times \left(\frac{100 - n}{100} \right) = Kg SO_2 / TJ \quad \text{--- (Equation 7)}$$

Where:

FE_{SO_2} = Emission Factor (kg/TJ)

2 = 2 SO₂/S [kg/kg]

S = Sulfur content in fuel [%]

r = Sulfur retention in ash [%]

Q = Net heat value in [TJ/kt]

10⁶ = (Unit) conversion factor, and

n = Efficiency of control technology and/or reduction efficiency (%)

5. Since the sulfur content of natural gas is expressed in g/m³, and not as a percentage, SO₂ emissions for natural gas must be calculated with the same procedure, but taking into account the difference in units.

Sulfur percentages must be obtained from Table A 5.8, since they have been adapted to local conditions in Mexico; however, Table A 4.9 shows sulfur percentages for some fuels that are not included in Table A 5.8. These values come from IPCC and should be used only if local values are not available.

During fuel combustion, part of the sulfur is retained in ash. Sulfur retention in ash for coal ranges from 5 to 60 percent, (usually less than 10 percent, see Table A 5.10 from Annex 5). The percentage depends on ash composition. Sulfur retention in ash for liquid fuels and biomass is minimal and can be neglected.

If abatement technologies are used for SO_x emissions reduction, estimated emission factors for SO₂ should be correspondingly reduced. Reduction efficiency values for different types of abatement technologies may vary between 45 and 95 percent.

SO₂ emissions should not be reported with the GHG inventory results, but should be reported separately.

5.5 CO₂ Emissions from Kraft Mill Lime Kilns and Calciners

Fossil-CO₂ emissions from Kraft mill lime kilns and calciners are estimated using the same approach as used for other stationary fossil fuel combustion devices—by determining how much fossil fuel is used in the kiln and estimating emissions from information on the fuel carbon content or emission factors. These CO₂ emissions are reported together with other fossil fuel-related CO₂ emissions.

Although CO₂ is also liberated from the CaCO₃ burned in the kiln or calciner, the carbon released from CaCO₃ is biomass carbon that originates in wood and should not be included in GHG emissions totals, but reported separately with other emissions from the combustion of biomass. The emission factors suggested for Kraft mill lime kilns and calciners are summarized in [Annex 5](#), Table A 4.5.

Example Calculation: GHG emissions from a natural gas-fired lime kiln.

A 1000 ton/day Kraft mill has a single gas-fired lime kiln. The mill's records indicate that it used 28.6×10^6 pounds of gas last year with a typical heat content of 21,000 Btu HHV/lb and a density of 0.77 kg/m^3 . The IPCC CO_2 emission factor for natural gas from boilers can be used for lime kilns since CO_2 emissions are a function only of gas composition. The IPCC CO_2 emission factor for natural gas is $55.9 \text{ ton CO}_2/\text{TJ}$ (after correcting for 0.5% un-oxidized carbon). For CH_4 , the mill decides to use the only available emission factor for Kraft mill lime kilns ($2.7 \text{ kg CH}_4/\text{TJ}$) and assumes that N_2O emissions are negligible based on the IPCC discussion of temperatures needed to generate N_2O . The kiln's GHG emissions are estimated as follows.

CO_2 emissions:

- $28.6 \times 10^6 \text{ lb gas/yr} \times 21,000 \text{ Btu HHV/lb} = 601 \times 10^9 \text{ Btu HHV/yr}$
- for natural gas, LHV is 0.9 times HHV (see Section 4.4.2)
- $601 \times 10^9 \text{ Btu HHV/yr} \times 0.9$ (to convert to LHV) $= 541 \times 10^9 \text{ Btu LHV/yr}$
- $541 \times 10^9 \text{ Btu/yr} \times (1.055 \times 10^{-6} \text{ GJ/Btu}) = 570,000 \text{ GJ/yr} = 570 \text{ TJ/yr}$
- $570 \text{ TJ/yr} \times 55.9 \text{ ton CO}_2/\text{TJ} = 31,900 \text{ ton CO}_2/\text{yr}$

CH_4 emissions:

- $570 \text{ TJ/y} \times 2.7 \text{ kg CH}_4/\text{TJ} = 1540 \text{ kg CH}_4/\text{yr}$

Using the IPCC CO_2 equivalency factor of 21, this equals 32 ton CO_2 -equivalents. This is a very small number compared to the CO_2 emissions (31,900 ton). In addition, the estimate is based on a small and old data set. Consequently, in the inventory results the mill might decide to report that the CH_4 emissions from this source are non-material to the inventory.

N_2O emissions:

- The IPCC's analysis of the temperatures needed to form N_2O in combustion processes suggests that it is unlikely that significant amounts of N_2O would be formed in lime kilns. The mill would probably decide to note this in the inventory results.

Total GHG emissions = $31,900 + 32 + 0 = 31,900 \text{ CO}_2\text{eq/y}$

5.6 Greenhouse Gas Emissions from Vehicles and Miscellaneous Fossil Fuel-Fired Equipment

Companies often own vehicles to transport raw materials, products, wastes, and employees. Companies may also own off-road vehicles and other types of fossil fuel-fired equipment. Because companies may need to include these emissions to complete their corporate GHG inventory, they are addressed in this tool. Companies should indicate in the results of the inventory whether these emissions have been included.

5.6.1 Greenhouse Gas Emissions from On-Road Vehicles

Companies wanting to include these emissions can base them on either fuel consumption statistics or information on distances traveled. If companies use fuel consumption

statistics to estimate CO₂ emissions, the estimates are derived using the same approach and emission factors as used for stationary fossil fuel combustion sources ([Section 7.1](#)).

Emission factors for CH₄ and N₂O for on-road sources can be found in [IPCC 1997c](#). A variety of parameters affect CH₄ and N₂O emissions from on-road vehicles, including type of vehicle, fuel consumed, operating characteristics, emission controls, maintenance procedures, and fleet age. The impacts of these parameters are reflected in the tables of emission factors for on-road vehicles included in IPCC 1997c. In general, CH₄ and N₂O emission factors for gasoline-fueled on-road vehicles combined and expressed in terms of CO₂-equivalents, range from 1.2 to 13.5 kg/GJ with a median value of 4.6 kg/GJ. Diesel-fueled sources are associated with somewhat lower CH₄ and N₂O emission factors, which range from 0.6 to 4.4 kg CO₂eq/GJ, with a median value of 1.0 kg CO₂eq/GJ. For context, CO₂ emission factors for liquid transportation fuels are usually close to 70 kg CO₂/GJ.

The emission factors in [IPCC 1997c](#) demonstrate that, for some types of on-road transportation sources, CH₄ and N₂O emissions represent only a small fraction of overall GHG emissions, whereas they can be more significant for other types of transportation sources. The guidance provided in the WRI/WBCSD 2004 mobile combustion tool only addresses CO₂ emissions from transportation sources, presumably due to the difficulty in assessing CH₄ and N₂O emissions and the small contribution to overall GHG emissions they represent for many of these sources.

It should be recognized that use of distance-based emission factors may result in less accurate emission estimates than those computed based on actual fuel consumption data. If, however, the company finds it more convenient to develop emissions estimates from statistics on distance traveled the CO₂ emission factors in WRI/WBCSD 2004 (reproduced in Annex C of the original tool) can be used.

5.6.2 Greenhouse Gas Emissions from Off-Road Vehicles and Equipment

Companies may own off-road vehicles and other fossil fuel-powered equipment that they want to include in the operational boundaries of the inventory. Fuel consumption statistics can be used to estimate CO₂ emissions from these sources using the emission factors in Table A 5.1 from [Annex 5](#). CH₄ and N₂O emissions can be a notable fraction of the GHG emissions from some of these sources. N₂O emissions for some of these sources are reported to be near 30 g/GJ or 9 kg CO₂eq/GJ, which can amount to more than 10% of the CO₂ emissions from such sources.

Emission factors for mobile sources have been published in a number of places. Some of the available information is summarized in Annex C of the original tool. IPCC's guidelines contain several different sets of emission factors without recommending a single set (IPCC 1997c). Table A 5.12 from [Annex 5](#) is from one of the sources cited by IPCC. The CO₂ factors in Table A 5.12 are from Table A 5.1 from [Annex 5](#) and are slightly different than those in the original table in IPCC 1997c due to correction for un-oxidized carbon, using IPCC recommendations. Table A 8 also includes overall CO₂-equivalent emission factors developed using the IPCC global warming potentials for CH₄ (21) and N₂O (310).

The published emission factors for CH₄ and N₂O from mobile sources vary from one protocol to another. The differences in N₂O, in particular, can impact the CO₂-equivalents by as much as 10%. Where companies need precise estimates for these sources, it is recommended that the various sources discussed in Annex C of the original tool be examined to determine which emission factors are most appropriate. In most cases, however, the emission factors in [Annex 5](#), Table A 5.12 will be adequate.

6. Carbon Dioxide Emissions from Make-up Chemicals

Non-carbonate chemicals are often used to make up for losses of sodium and calcium from the recovery system. Small amounts of CaCO₃ and Na₂CO₃ may also be used for this purpose. The carbon contained in these chemicals is usually of fossil origin, although in some cases (e.g., Na₂CO₃ purchased from soda-based semi-chemical mills) it can be derived from biomass. In this calculation tool, it is assumed that the carbon in the make-up chemicals escapes as CO₂ from the lime kiln or recovery furnace⁷. These emissions are estimated by assuming that all of the carbon in CaCO₃ and Na₂CO₃ used in the recovery and caustic areas is released to the atmosphere. The amounts are usually small enough that under normal circumstances it is reasonable to use either mill purchasing records or industry norms to develop the estimates. If the carbon in make-up chemicals is biomass in origin (an uncommon situation), the CO₂ released from it is not considered a GHG emission, and in these cases this carbon is not included in GHG totals, but is recorded as additional information with other biomass combustion information.

Conversion factors for estimating fossil-CO₂ releases from the use of carbonate-based make-up chemicals in the pulp mill are shown [in Annex 6](#), Table A.6.

It is important to note that calcium make-up is required because of losses from the caustic area, most of which are in the form of calcium carbonate. This material is usually land filled, thereby sequestering the carbon contained in the calcium carbonate. Because the default method in this calculation tool does not consider this loss of carbon from the system, the estimated CO₂ emissions from make-up calcium carbonate will be higher than actual emissions. Where these emissions are significant, companies may want to perform more detailed analyses required to correct estimates to account for the carbon that leaves the caustic area as calcium carbonate.

Example Calculation: Kraft mill using CaCO₃ for make-up at the lime kiln.

A 2000 tpd Kraft mill determined from mill records that it uses about 7000 tons (7700 short tons) CaCO₃ a year as make-up in the caustic area (make-up rate of about 2% for this mill). This CaCO₃ is from a source where carbonate would be expected to be fossil (not biomass) in origin. The emissions are estimated as follows.

- (7000 tons CaCO₃/yr) x 440 kg CO₂/tons CaCO₃ = 3,080,000 kg CO₂/yr = 3080 tons CO₂/yr

⁷ Causticizing is the process by which the green liquor produced in the baking of paste to sulphate is turned in white liquor with caustic lime, allowing therefore the recycling of the chemical agents of the baking.

6.1 Emissions from Limestone or Dolomite Used in Flue Gas Desulphurization (FGD)

Limestone (CaCO_3) and dolomite ($\text{CaCO}_3\text{MgCO}_3$) are basic raw materials used by a wide variety of industries, to absorb sulfur in flue gas desulphurization (FGD) systems and fluidized bed boilers at power utilities and industrial plants. For example, wet limestone “scrubbers” use limestone slurry—mixtures of water and very finely crushed limestone—to prevent sulfur dioxide from passing through smokestacks. A rapid chemical reaction between sulfur dioxide gas and crushed limestone combines the gas with calcium and oxygen, forming a removable solid waste. During this reaction, the limestone is heated and CO_2 is generated as a by-product. Some coal-fired boilers at pulp and paper mills incorporate such FGD systems.

Carbon dioxide emissions associated with the use of limestone as an absorbent material can be calculated by multiplying the quantity of limestone or dolomite consumed by its average carbon content, approximately 12% by mass for limestone and 13% for dolomite (based on stoichiometry). This approach assumes that all carbon in the mineral is oxidized and released and that impurities constitute a minor fraction of the material. Converting these percentages to a mass ratio of CO_2 to limestone using a molecular weight ratio produces emission factors of 0.440 ton CO_2 /ton limestone consumed and 0.447 ton CO_2 /ton dolomite consumed. The quantity of limestone consumed can be estimated based on purchase records or metered data (e.g., scales).

Limestone used for industrial purposes is often a combination of pure limestone, dolomite, and minor impurities (e.g., magnesia, silica, and sulfur). Uncertainties in estimates of CO_2 emissions from limestone used as absorbent are due, in part, to variations in the chemical composition of limestone.

7. Greenhouse Gas Emissions from Anaerobic Treatment of Wastewater or Sludge

Most existing GHG protocols address waste treatment plant emissions only from anaerobic treatment and digestion processes. Although aerobic and facultative treatment systems may have zones with depleted dissolved oxygen, methane generation rates in aerated stabilization basins, activated sludge systems, and their associated retention ponds would be expected to be much lower than those estimated for anaerobic systems. Due to lack of data and their relative quantities compared to other processes, emissions from aerobic and facultative treatment operations are seldom estimated. IPCC, recommends a default assumption that a methane conversion factor of zero be used for aerobic systems ([IPCC 1997c](#)).

For anaerobic systems, only CH_4 emissions need to be estimated. The CH_4 emissions from company-owned anaerobic systems will be reported as direct emissions. The CO_2 emitted from wastewater and sludge treatment operations contains biomass carbon which is not included in GHG totals. Where this biomass CO_2 is not combustion related (e.g., it is not formed from combustion of methane), it is often excluded from inventory results altogether. In addition, N_2O emissions from treatment plants, specifically from industrial sources, have been found to be small and probably occur only after the wastewater is discharged ([IPCC 1997c](#)).

7.1 Anaerobic Treatment Operations where Off-Gases are captured

In many cases, anaerobic treatment systems are covered and the gases are collected and burned. One of the purposes of these collection systems is the prevention of odors, and to accomplish this objective the systems must be highly efficient. For purposes of a GHG inventory it is reasonable to assume, therefore, that where methane emissions from anaerobic treatment operations are captured and burned, the collection and destruction is almost complete⁸ and no methane is emitted except what is lost during the collection process. Because the CO₂ produced in burning the CH₄ contains biomass carbon, it does not need to be reported in GHG inventory totals, but data should be reported separately. If circumstances at a mill suggest that non-trivial amounts of methane are escaping collection, the mill may need to undertake efforts to account for these releases, but such circumstances are expected to be unusual at mills that collect and burn these gases. If the gases are collected but released to the atmosphere rather than being burned, they should be included in the inventory.

7.2 Anaerobic Treatment Operations where Off-Gases are released to the Atmosphere

Where off-gases from anaerobic treatment operations are not collected and burned, it is necessary to estimate the releases of methane to the atmosphere. In some cases, for instance where the gases are released through a vent in a covered vessel, the releases can be measured directly. In most other cases, they must be estimated.

This tool recommends the use of the IPCC default methodology described in the May 2000 Good Practice Guidance (IPCC GPG) document and also shown in Equation 8 (IPCC 2000a). Although the IPCC document allows the equation to be applied to systems that are not completely anaerobic (by multiplying the result by an arbitrary adjustment factor of less than one), there are no data currently available to support the selection of the adjustment factor. It is recommended, therefore, that methane emissions be estimated only from anaerobic treatment or sludge digestion systems until factors for other types of systems are available.

$$\boxed{\text{Anaerobic Treatment Plant Methane Emissions (kg / y)} = (OC \times EF) - B} \text{ -- (Equation 8)}$$

Where: OC = BOD or COD of the feed to the anaerobic system, kg/year

EF = emission factor, default values = 0.25 kg CH₄/kg COD in the feed or 0.6 kg CH₄/kg BOD in the feed (or another BOD-based factor developed by multiplying the COD-based factor of 0.25 kg CH₄/kg COD by the site-specific COD/BOD ratio)

B = methane captured and burned, kg CH₄/year, determined on a site-specific basis

⁸ It is reasonable to assume that all methane combusted is destroyed (usually 98%), companies should be careful to check that all methane is being captured during collection. The quantity of fugitive CH₄ emissions can be determined by monitoring the amount of gas being flared compared to the estimated waste gas produced.

If the solids are handled separately, emissions from sludge digestion would be calculated using Equation 9. In cases where sludge is burned, it is included in the calculations for GHG emissions from biomass burning discussed in [Section 5](#).

$$\text{Anaerobic Sludge Digestion Plant Methane Emissions (kg / y)} = (OCs \times EFs) - B \quad \text{-- (Eq. 9)}$$

where: OCs = organic content of the sludge

EFs = emission factor, in units consistent with OCs - IPCC's default value is 0.25 kg CH₄/kg COD in the sludge feed

B = methane captured and burned, kg CH₄/yr, determined on a site-specific basis

Example calculation: Recycled paperboard mill with anaerobic treatment but no gas recovery.

A recycled paperboard mill uses an anaerobic treatment plant to treat wastewater containing 10,000 kg COD/d. The mill generates wastewater 300 days per year. The IPCC default value for CH₄ generation from anaerobic treatment systems is 0.25 kg CH₄/kg COD in the feed. The CH₄ emissions are calculated as follows:

- OC = 10,000 kg/d x 300 d/yr = 3,000,000 kg COD/yr
- CH₄ generated = 3,000,000 kg COD/yr x 0.25 kg CH₄/kg COD = 750,000 kg CH₄/yr
= 750 tons CH₄/yr

Using the IPCC GWP (21), this equals 15,750 tons CO₂eq/yr

8. GHG Emissions Attributable to Electricity, Heat and Steam Imports and Exports

Consumption of electrical power or steam (or hot water) purchased from another company usually results in generation of indirect emissions, i.e., “emissions that are a consequence of activities of the reporting company, but occur from sources owned or controlled by another company” (WRI/WBCSD 2004). Of course, virtually every raw material, energy source, and service used by a company has an indirect emissions impact. Many GHG programs, such as the Mexico GHG Program however, selectively include indirect emissions related to the purchase and consumption of electricity, heat and steam (Scope 2 emissions) because they are applicable to a wide range of activities and can be a significant component of a company’s total GHG impact. This document therefore, provides a quantification methodology to estimate indirect emissions from electricity, heat and steam (or hot water) transfers. These Scope 2 emissions should be reported separately from direct emissions and other indirect emissions

8.1 Electricity, Heat and Steam Imports

To estimate Scope 2 emissions, companies should use the most appropriate purchased power emission factor available. In Mexico, the National Electrical Power System (SEN) is currently made up of four mostly independent systems, each consisting of power generating plants that are interconnected in order to satisfy demand requirements. Of these systems, the Northeast will definitely be hooked up to the rest of the SEN once the new electrical power lines under construction by the Ministry of Energy and CFE have been connected to the network. However, it is not foreseen that the Baja California system will be connected to the rest of the country, since it is not economically justified (USAID, 2002).

The four independent systems are listed below and their area of influence is shown in the following figure:

- Interconnected System
- Northwest System
- Baja California System
- Baja California Sur System



Figure 1: National Electrical Power System divided into systems

The interconnected system allows satisfaction of user demands through collective contributions by each region and, in principle, each power generating station that is part of the system contributes proportionately to each user's consumption. In this manner, it does not matter where geographically the user is located within the system, since all of the generating stations have the possibility of supplying any user. [Annex 7](#) presents emission factors for estimating GHG inventories resulting from the purchase of electrical power.

8.2 Electricity, Heat and Steam Exports

To be consistent with accepted GHG accounting protocols, this guidance document suggests a format (see [Annex 8](#), Table A 8.1) for reporting results wherein a mill reports all direct emissions associated with electricity and steam generation, whether they are used

internally or exported. The format of result tables, however, allows the mill to separately show those emissions attributable to exported power and steam. These tables also allow companies to compare the carbon content of exported power (in kg CO₂/MWh) to that on the grid into which the power is exported. Companies may find this a helpful for highlighting the beneficial environmental attributes of exports of biomass-based power and power produced by combined heat and power (CHP) systems.

This tool uses the method recommended by WRI/WBCSD for estimating the impact of exported power emissions. This method involves estimating the emissions generated by the mill to produce the exported power. Because exported electricity from mills is usually generated in CHP systems, companies will often need to use the methods for CHP systems (described in [Section 8.4](#)) to estimate emissions attributable to the exported power.

8.3 Steam Imports

In many cases where steam is imported by a mill, the steam is produced by a nearby CHP system not owned or controlled by the company. In these cases, the indirect emissions reported by the mill can be estimated using the allocation method (described in next section). In other cases, the contractual arrangement between the mill and power producer may define how the emissions from the power plant are to be allocated between the power and the steam sold by the power plant. In these cases, the allocation should be explained in the results.

8.4 Allocating Emissions from Combined Heat and Power (CHP) Systems

Where electricity is produced by combined heat and power (CHP) systems, it may be necessary to allocate the emissions from the CHP system to the various output energy streams. Of course, if the mill owns the CHP system and uses all of its output, allocation is not necessary because all of the emissions are direct emissions for the mill. In many cases, however, a mill may either receive CHP energy from an outside provider or export a portion of its own CHP output. In this cases it is necessary to estimate the indirect emissions associated with the imported electricity or/and steam.

Although there are several methods for allocating emissions from CHP systems, the “efficiency” method is recommended. The efficiency method is recommended because it attempts to relate energy outputs to the amounts of fuel used to generate them and, by extension, to the GHG’s produced in generating them. Where a company uses an alternative method, the method should be explained in the results.

The efficiency method is one of three methods provided by WRI/WBCSD, and the one that is recommended. There are two versions of the method. The simplified efficiency method is less complex but involves several assumptions about equipment efficiencies. It is expected that the simplified method will be adequate for many mills and, therefore, it is included in this report as a default method. The detailed efficiency method is more complicated but can use site-specific design and operating data that companies sometimes have for CHP systems. This method will not be addressed in this report, but, for those companies that wish to use it, it can be looked up in the original WRI/WBSCD tool for the pulp and paper sector.

8.4.1 Simplified Efficiency Method

The efficiency method requires use of assumed efficiency factors for the production of power and steam, or actual efficiency factors for each steam or power generation device based on detailed process design and operating information. It is assumed that the efficiency of producing hot water is the same as the efficiency of producing steam. The simplest approach to applying the efficiency method is to assign a single efficiency factor to all power output and a single efficiency factor to all heat (steam and hot water) output. This information is used to compute an efficiency ratio equal to the heat production efficiency divided by the power production efficiency. For example, if the CHP system produces steam at 80% efficiency and power at 40% efficiency the ratio is 2. The efficiency ratio is used rather than the individual efficiencies because (a) it is the ratio that controls the allocation of emissions rather than the individual efficiencies, and (b) the individual efficiencies are constrained by the energy balance so it is not possible to specify both independently.

Emissions from the CHP system are allocated between the heat and power outputs, based on this ratio of efficiencies, using Equations 10 and 11. This approach is referred to in this report as the simplified efficiency method. The simplified efficiency method is recommended for mills that lack, or choose not to use, detailed design and operating data from CHP systems.

$$E_H = \left[\frac{H}{H + P * R_{eff}} \right] * E_T \text{----- (Equation 10)}$$

$$R_{eff} = \frac{e_H}{e_P} \text{----- (Equation 11)}$$

Where:

E_H = share of emissions attributable to heat production, tons GHG/yr

E_T = total emissions from the CHP plant, tons GHG/yr

H = heat output, GJ/yr

P = power output, GJ/yr

R_{eff} = ratio of heat production efficiency to power production efficiency

e_H = assumed efficiency of typical heat production (default = 0.8)

e_P = assumed efficiency of typical electric power production (default = 0.35)

The emission share attributable to electric power production is assigned from the relation:

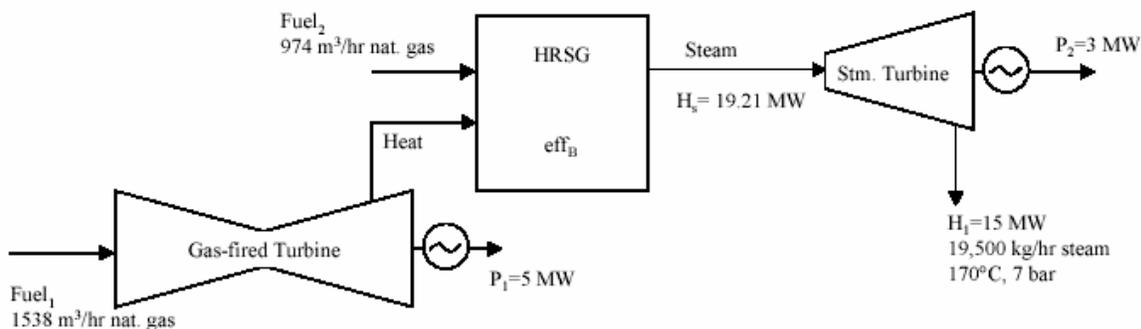
$$E_p = E_T - E_H \text{ ----- (Equation 12)}$$

where: E_p = share of emissions attributable to electric power production

Example Calculation:

A mill has the CHP system shown in the following figure, but is lacking (or chooses not to use) detailed energy balance information. Instead, the company chooses to use the simplified efficiency method and the default efficiencies recommended by WRI/WBCSD for the US; 0.35 for power generation and 0.8 for steam generation.

Figure 2: Example Figure for CHP System



Using these assumed efficiencies, emissions can be allocated among the three outputs of the CHP system as follows (using a basis of one hour of operation):

Total system emissions:

Fuel1:

CO₂ (1538 m³/hr) x (0.039 GJ/m³) x (55.9 kg CO₂/GJ) = 3353 kg CO₂/hr
 CH₄ (1538 m³/hr) x (0.039 GJ/m³) x (0.0006 kg CH₄ /GJ) x (21 CO₂eq/CH₄) = 0.76 kg CO₂eq./hr
 N₂O (1538 m³/hr) x (0.039 GJ/m³) x (0.0001 kg N₂O /GJ) x (310 CO₂-eq./N₂O) = 1.86 kg CO₂eq/hr

Total Fuel1 emissions = 3356 kg CO₂eq/hr

Fuel2:

CO₂ (974 m³/hr) x (0.039 GJ/m³) x (55.9 kg CO₂/GJ) = 2123 kg CO₂/hr

CH_4 (974 m³/hr) x (0.039 GJ/m³) x (0.0014 kg CH₄ /GJ) x (21 CO₂eq/CH₄) = 1.12 kg CO₂eq/hr

N_2O (974 m³/hr) x (0.039 GJ/m³) x (0.0001 kg N₂O /GJ) x (310 CO₂-eq./N₂O) = 1.18 kg CO₂eq/hr

Total Fuel2 emissions = 2126 kg CO₂eq/hr

Total CHP system emissions = 3356 + 2126 = 5482 kg CO₂eq/hr

Total system power output = P1 + P2 = 8 MW

$$R_{\text{eff}} = \frac{0.8}{0.35} = 2.3$$

$\text{EH} = \left[\frac{15\text{MW}}{15\text{MW} + (8\text{MW} \times 2.3)} \right] = 5482 \text{ kg CO}_2\text{eq} = 2462 \text{ kg CO}_2\text{eq} = 20,681 \text{ ton CO}_2\text{eq/yr}$
at 350 d/yr operation.

Using the simplified efficiency method with default power and steam efficiency factors, therefore, the emissions from the CHP system are allocated to the output streams in the following percentages:

- Percentage of CHP emissions to heat output = 100*2462/5482 = 44.9%
- Percentage of CHP emissions to power output = 100*3020/5482 = 55.1%

These percentages can be used to allocate all GHG emissions from the CHP system.

Emission factors can be developed for the energy outputs:

- Emission factor for CHP heat output = (2462 kg CO₂-eq./hr)/15 MW
= 164.1 kg CO₂-eq/MWh
- Emission factor for CHP power output = (3020 kg CO₂-eq./hr)/8 MW
= 377.5 kg CO₂-eq/MWh

9. Presenting Inventory Results

This document provides an example format for summarizing and/or reporting inventory results. Companies may find other formats more convenient or appropriate, however, and are free to choose the format best suited to their needs. It is important that the output from using this calculation tool be (a) disaggregated to the extent possible to ensure transparency; and (b) accompanied by key information needed to interpret the results.

[Annex 8](#) contains four tables that companies may use to present inventory results.

Table A 8.1 contains an example format that can be used for recording Scope 1 (direct emissions). These are emissions within the boundaries of the inventory from sources

owned or controlled by the company. The company is free to select a method to determine ownership of emissions from sources only partly owned or controlled by the company, but the method should be described in the presentation of results. Also in this table is an example format for including information regarding direct emissions which are associated with electricity or steam that is sold to another entity. Companies are encouraged to use this or a similar format to characterize the impact of electricity and steam exports, which can have a significant impact on a facility's greenhouse gas profile.

Table A 8.2 is a suggested format for recording indirect emissions (Scope 2 and Scope 3). These are emissions from sources within the operational boundaries of the inventory but owned by another entity, such as emissions attributable to imports of power and steam and imports and exports of fossil fuel derived CO₂. Companies are encouraged to use this or a similar format to characterize the impact of outsourced operations (power islands in particular) that have a significant impact on a facility's greenhouse gas profile.

Table A 8.3 provides an example of a format that can be used for recording the emission factors used to prepare the inventory. Companies are encouraged to include this information to make the results of the inventory more transparent.

Table A. 8.4 provides an example of format that can be used for recording the CO₂ emissions derived from the biomass burned. These emissions are reported separately from the scopes of the GHG inventory (scope 1, 2 and 3).

10. Excel Worksheet Structure for Estimating Emissions from Pulp and Paper Mills in Mexico

The calculation tool has a number of Excel work sheets, each one with a different information and calculation purpose. A summary follows for each one.

Table 1. Purpose of the Different Worksheets used in this Tool	
Introduction	Introduction to this tool
Table of Contents	List of all worksheets in the tool
Tasks in the Inventory	Inventory Scope Definition
Direct Sources – Stationary fossil fuel combustion	This worksheet calculates CO ₂ emissions from burning fossil fuels in stationary sources (includes CH ₄ and N ₂ O emissions in CO ₂ eq.)
CH ₄ and N ₂ O	This worksheet calculates CH ₄ and N ₂ O emissions from stationary sources that burn biomass
SO ₂	This worksheet calculates SO ₂ emissions, a local pollutant in Mexico
Direct Sources – Mobile and Transportation Sources	This worksheet calculates CO ₂ emissions produced by the use of vehicles owned or controlled by the company
Direct Sources – Waste Management (wastewater treatment)	This worksheet calculates CH ₄ emissions as CO ₂ eq produced from waste management and treatment systems owned by the company
Make-up Carbonates	This worksheet calculates CO ₂ emissions from using chemical products such as calcium carbonate
Power Exports	This worksheet calculates CO ₂ emissions related to exports of power and steam to installations that are not owned by the company nor are under its control
CHP Allocation	This worksheet provides a methodology to allocate and calculate CO ₂ emissions produced by CHP systems
Indirect – Power Imports	This worksheet calculates CO ₂ emissions from buying electrical power from the National Electrical Power System
CO ₂ Imports and Exports	This worksheet calculates emissions produced from the importation and exportation of CO ₂ to calcium carbonate precipitation plants
Summary Table	Report on GHG inventory results
Customization of Emission Factors	Support worksheet to customize EFs based on fuel characteristics
Energy Content (Heating Values)	Reference worksheet on heat value for different fuels
Conversion Factors	Reference worksheet to convert units used to calculate GHG
Support information on Biomass	Worksheet with support information to calculate CO ₂ emissions produced by use of biomass fuels

10.1 Supplementary Step by Step Instructions for the Worksheets

In this section, the user will find a step-by-step guide on how to apply the different worksheets that make up the calculation tool for the estimation of GHG and SO₂ emissions.

Notes:

- The factors are selected and values calculated automatically by the tool and shown in the gray colored cells.
- The user can directly substitute the factor or value shown in the gray cells and the program will use these new values for the calculations.
- Conversion of the amount of fuel used into power units (GJ) is done automatically by the tool based on the quantity and type of fuel inputted by the user.
- In Annex 3 and the “Heat Value” spreadsheet, the user will find the heat values for different types of fuels.
- The units used are from the International System (MKS), however, the annexes contain emission factors and parameters in other measurement systems preferred by authorities or countries responsible for the information.

Inventory Operations

Step 1. Inventory Name

- Row 8: Input the name with which the inventory will be identified, for example: “GHG Inventory for the XXX Paper Plant of Mexico”.

Step 2. Inventory Boundaries

- Row 10: Input a description of the operations that are included within operational boundaries: stationary combustion sources, mobile sources, addition of chemicals, etc.

Step 3. Additional Inventory Information

- Row 13: Input additional information that may help understand the operational boundaries—for example, if all power is imported or produced at the mill, if all stationary sources are owned the company or some are leased from other companies, if biomass is used at some of the stationary sources, etc.

Step 4. Emissions Allocations

- Row 16: Input how the organizational boundaries are defined, and any other information that helps to understand how emissions are allocated from partially controlled sources: based on equity share or financial/ operational control percentages, or on other allocation agreements.

Step 5. Identification of Operations

- Rows 20 to 56: Mark with an “X” to identify operations that are included in the inventory and ownership or control by the company.

Direct Emissions – Stationary Fossil Fuel Combustion

Step 1. Calculation of the amount of fuel used

- Row 22: Select from the drop-down menu the stationary sources included in the inventory: Boilers, driers, turbines, etc., and in the next column enter the type of fuel they use
- Column A: Enter the amount used by each one of these sources in the units showed in the drop down menu. (e.g., liters, tons).
- Column B: The value will be automatically calculated from the amount of fuel entered in power units (GJ) and from multiplying the Heat Value of the selected fuel.

Step 2. Selection of Emission Factor

- Column C: The tool automatically selects an Emission Factor based on the fuel (the EF values are taken from those in corresponding table in this section: rows 49 to 81). In case the user wishes to make the selection manually, the value shown in the cell can be erased and a value from Table A 5.1 in [Annex 5](#) of this guideline chosen. The table has default values for emission factors that can be used in case local values are not available.
- Column D: Enter units for the emission factor: Kg CO₂ /GJ

Step 3. Auto-calculated value / obtaining CO₂ emissions in metric tons

- Column E: Auto-calculated emissions values in CO₂eq in kg
- Column F: Auto-calculated emissions values in CO₂eq in metric tons

Step 4. Addition of CO₂ Emissions

- Cell “37 F”: Auto-calculated value of the total CO₂ emissions from different stationary combustion sources.

Step 5. CH₄ and N₂O Emissions

- Cell “38F”: Auto-calculated value in the emissions from the worksheet “Direct CH₄ & N₂O” transformed into CO₂eq through the GWP and automatically imported into the “Direct – Stationary Combustion Sources”.

Step 6. CO₂ Imports and Exports

- Cell “39 F”: Auto-calculated value of the emissions from the worksheet “CO₂ Importation and Exportation” and automatically imported into the worksheet “Direct

– Stationary Combustion Sources”. These emissions come from CO₂ importation to the plant from PCC.

Step 7. CO₂ emissions from Stationary Fossil Fuel Combustion

- Auto-calculated value of the previous total CO₂ emissions: emissions from stationary sources and importation and exportation of CO₂.

Note: When the user selects from the dropdown menu the options for “Turbines on Site” and “Combustion units assigned the PCC plant” in the worksheet “Direct – Stationary Combustion Sources”, the calculated CO₂ emission values are exported directly to the “Indirect – Power Exportation” and “CO₂ Importation & Exportation” worksheets, respectively, since the calculated values are used in the aforementioned worksheets. If the user selects these options by mistake, they will have to be erased manually from the worksheets that they have been exported to, otherwise they will remain in the assigned worksheets.

Direct CH₄ and N₂O Emissions from stationary combustion sources

Step 1. Calculation of the amount of fuel used

- Row 17: Select from the dropdown menu the stationary sources included in the inventory: Boilers, driers, turbines, etc., and enter in the next column the type of fuel they use
- Column A: Enter the amount used by each one of these sources
- Column B: Enter the units to measure the amount of fuel used (kg, m³, etc).

Step 2. Calculation of the energy content of the fuel

- Column C: Auto-calculated value of the amount of fuel in power units (GJ).

Step 3. Emission Factor for CH₄

- Column D: The tool automatically selects an Emission Factor for CH₄ based on the previously chosen fuel (these EF values are taken from the EF table in the “Direct – Stationary Combustion Sources” worksheet: rows 49 to 81). In case the user wishes to make this selection manually, the value shown in the cell can be erased and a value from Table A 5.1 in [Annex 5](#) of the guideline document introduced in the rows mentioned in this section, where default emission factors are available that can be used when local values are not available.

Step 4. Emission Factor for N₂O

- Column D: The tool automatically selects an Emission Factor for N₂O based on the fuel previously chosen (these EF values are taken from the EF Table in worksheet “Direct – Stationary Combustion Sources”: rows 48 to 81). In case the user wishes to make this selection manually, the value shown in the cell can be erased and a value from Table A 5.1 in [Annex 5](#) of the guideline document introduced in the rows

mentioned in this section, where default emission factors are available that can be used when local values are not available.

Step 5. Calculation of CH₄ and N₂O Emissions

- Column F: Auto-calculated value for CH₄ emissions in kg
- Column G: Auto-calculated value for N₂O emissions in kg

Direct Emissions of SO₂ from Stationary Fossil Fuel Combustion (reported separately from Scope 1 since they are not a GHG)

Step 1. Calculation of the amount of fuel used

- Row 20: Select from the list the name of the source of SO₂ emissions and the type of fuel used.
- Column A: Enter the amount of fuel (liters, tons, kg, etc).

Step 2. Development of the SO₂ Emission Factor

- Column B: Enter the sulfur content of the fuel (in percentage, %). Tables 5.8 and 5.9 in Annex 5 of this guidance document contain default values for different fuels.
- Column C: Enter the ash sulfur retention value (r). Table A 5.10 contains default values of ash sulfur content for different fuels.
- Column D: Enter the efficiency value for the air emissions control equipment (in %).
- Column E: Enter the fuel heat value (in TJ/kt). Table A.3 in annex 3 contains default heat values for different fuels.
- Column F: Auto-calculated EF value for SO₂.
- Column G: Auto-calculate for SO₂ emissions in metric tons.

Direct – Mobile and Transportation

Part 1 – Calculated emissions based on fuel consumption

Step 1. Source Description

- Column A: Enter source description (terrestrial, train or sea): Trucks, train, ships, etc.

Step 2. Calculation of the amount of fuel used

- Column B: Enter the type of fuel used: gasoline, diesel, LPG, etc
- Column C: Select from the dropdown menu the units of the type of fuel used: liters, gallons, m³, etc.
- Column D: Enter the amount of fuel used

Step 3. Calculation of Power Used

- Column E1: The tool automatically selects a Heat Value based on the units and type of fuel used.

- Column E2: Manual input of Heat Value (in case the user does not wish to apply the one selected by the tool). Sometimes, this value is provided by the fuel supplier (only if the user has the value, otherwise use one of the default values recommended by the IPCC, column E1 and auto-selected by the tool).
- Column F: Auto-calculated value in GJ for the power used

Step 4. Selection of the Emission Factor

- Column G1: The tool automatically selects an EF based on the type of fuel used. This EF value comes from the IPCC EF table included in this worksheet.
- Column G2: Enter the adapted EF value (only in case of availability of this value, otherwise use one of the default values recommended by the IPCC).
- Column I: Auto-calculated value of CO₂ emissions in metric tons

Part 2. Calculated CO₂ emissions based on the distance traveled by vehicles

Step 1. Source Activity

- Column A: Enter the source description: private car, truck, motorcycle, hybrid car, etc.
- Column B: Description of different transportation sources.
- Column C: Enter the activity level: amount of miles or kilometers traveled by the vehicle.
- Column D: Description of the activity level units: miles, kilometers.

Step 2. Selection of Emission Factor

- Column E1: EF default values for cases where a local or adapted EF value is not available.
- Column E2: Enter the EF adapted value (only in case this value is available).

Step 3. Calculation of CO₂ emissions in metric tons

- Column F: Auto-calculated value of CO₂ emissions in metric tons

Part 3. CO₂ Emissions associated with mobile equipment based on fuel consumption

Step 1. Calculation of the amount of fuel

- Row 122: Input source description and select, from dropdown menu in the next column, the type of fuel.
- Column A: Enter the amount of fuel used in energy units (energy content)
- Column B: The tool automatically selects a Heat Value based on the units and type of fuel used.
- Column C: Auto-calculation of the amount of fuel in energy units (GJ).

Step 2. Selection of Emission Factor

- Column D: The tool automatically selects an Emission Factor based on the fuel used (these EF values are taken from the EF table in the “Direct – Stationary Sources” section, rows 49 to 81). In case the user wishes to make this selection manually, the value in the cell can be erased and a value selected from Table A 5.1 in Annex 5 of this document and in the rows mentioned in this section, from where default emission factor values can be used in case local ones are not available.

Step 3. Calculation of CO₂ emissions

- Column E: Auto-calculated value for CO₂ emissions in tons.

Direct – Waste Management: Anaerobic wastewater treatment systems (companies should select only one of the following methods)

Method 1. For anaerobic wastewater treatment and sludge digestion with gas collection systems.

Step 1. Calculation of the amount of gas collected

- Column A: Enter amount of gas collected from the system (Standard dry m³/year)
- Column B: Enter gas recovery efficiency from the system. A default value is included for when it is unknown.
- Column C: Enter fraction of gas burned at outlet. A default value is included for when it is unknown.
- Column D: Enter the value for the amount of methane contained in the gas. A default value is included for when it is unknown.
- Column E: Auto-calculated value for the amount of methane emitted (in dry m³)
- Column F: Auto-calculated value for the amount of methane emitted in metric tons.
- Column G: Auto-calculated value of CO₂-equivalents in metric tons (using the GWP of 21 to convert methane to CO₂-equivalents).
- Column H: Auto-calculated value for the amount of CO₂ generated for the methane burned. These emissions are not reported in the Scope 1, are reported in the Biomass section due to this CO₂ is generated from the methane burned produced from organic waste treatment (biomass).

Step 2. Total methane emissions

- Row 49: Total of all emissions from all sources that produce methane.

Method 2. For anaerobic wastewater treatment systems and sludge digestion without gas collection or gas collection efficiency is unknown.

Step 1. Calculation of methane emissions

- Column A: Enter the amount of organic matter sent to treatment (kg of BOD or COD).
- Column B: Enter the EF for methane (a default EF is included for BOD and COD for when it is unknown).
- Column C: Enter the amount burned or collected (kg of methane/year)
- Column D: Auto-calculated value for the amount of methane liberated (kg/year)
- Column E: Auto-calculated value, methane emissions in metric tons.
- Column F: Auto-calculated value, emissions in CO₂ equivalents.

Step 2. Total methane emissions

- Auto-calculated value for total methane emissions from anaerobic wastewater treatment systems and/or sludge digestion.

Step 3. Sum total of methane emissions

- Auto-calculated value for all methane emissions by methods one and two.

Direct Emissions – Carbonate Addition

Step 1. Calculation of the amount of carbonate used in the mill

- Rows 9 and 10: Enter the amount of chemical being used: calcium carbonate or sodium carbonate.
- Column E: Default Emission Factor
- Column F: Rows 9 and 10: Auto-calculated value for CO₂ emissions.

Power and/or Steam Exportation

Step 1. Calculation of total electricity and/or steam production

- Row 25, column A: Enter description of flows that are being exported (electricity or steam), enter the total amount of electricity or steam produced by the generator in MW/h. This value is estimated for the source identified as “On Site Combustion Turbines” in the worksheet “Direct – Stationary Combustion Sources” and is exported directly to this worksheet or can be input manually for the user.

Step 2. Calculation of CO₂ emissions

- Column B: Enter total amount of CO₂-equivalents of emissions produced by power and/or heat generation.

Step 3. Flow Exportations

- Column C: Enter the total amount in kW/h of power or steam exported.

Step 4. Indirect CO₂ Exportations

- Column D: Auto-calculated value for indirect CO₂ exportations related to power or steam exportation.

Step 5. Carbon Intensity

- Column E: Auto-calculated value for carbon intensity for exported power or steam.

Step 6. Total CO₂ Emissions

- Row 35: Auto-calculated value for CO₂ emissions for exported power or steam.

Note: In case the option “On-Site Turbines” is selected from the worksheet “Direct – Stationary Combustion Sources” and later on this item is eliminated, the value calculated on the page “Power Exportation” worksheet must be erased.

Assignment of Combined Heat and Power Systems

Step 1. Calculation of heat loss

- Column A: Enter the heat loss value (process heat or other type of heat produced) in GJ, BTU or kWh.

Step 2. Calculation of energy loss

- Column B: Enter the energy loss value (with the same units as in column A).

Step 3. Amount of fuel used

- Column C: Enter the amount of fuel used in energy units (power content and in the same units as columns A and B).

Step 4. Units used

- Column D: Enter units used in columns A, B and C (all three have to be the same to be consistent with previous calculations).

Step 5. Direct total emissions from Combined Heat and Power system facilities.

- Column E: Enter total CO₂ emissions from the CHP system in CO₂-equivalents (any of the methods described in the worksheet “stationary combustion sources” to estimate CO₂ emissions).

Step 6. Assigned efficiency coefficients

- Column F: Enter the assigned efficiency coefficient (heat production efficiency divided by power production efficiency, the WRI/WBCSD Protocol assumes a coefficient of $0.8/0.35 = 2.29$).

Step 7. Auto-calculated value for power production efficiency.

Step 8. Auto-calculated value for heat production efficiency

Step 9. Auto-calculated value. Shared emissions assigned to heat production.

Step 10. Auto-calculated value. Shared emissions assigned to power production.

Step 11. Auto-calculated value. Emission factor for heat production.

Step 12. Auto-calculated value. Emission factor for power production.

Indirect Emissions – Importation of electric power and/or steam

Step 1. Calculation of the amount of imported electricity and/or steam

- Row 20: Enter source description to which electricity or steam is imported.
- Column A: Enter the amount of power and/or steam that is imported in MW/h.

Step 2. Selection of emission factor

- Column B: Enter emission factor value (in kg of CO₂/MWh) being used to convert emissions to CO₂-equivalents. Tables A.7 and A.7.1 in Annex 7 contain emission factor values for power production in Mexico.

Step 3. Auto-calculated value for CO₂ emissions

- Column C: Auto-calculated value of CO₂ emissions for electrical power importation

Step 4. Description of Emission Factor basis

- Column D: Enter a description of where the emission factor was obtained (source) or estimation method.

Step 5. Total CO₂ emissions

- Row 31, column C: Total of all sources that import power and/or steam and produce CO₂ emissions.

Fossil CO₂ Importations and exportations, including exportations to calcium carbonate precipitation plants (CCP)

Step 1. Fossil CO₂ Generation

- Column A: Enter the total amount of fossil CO₂ generated by burning fossil fuels (in metric tons). This value is exported directly by the tool for the sources selected in the inventory as “Combustion Units assigned to the PCC Plant” or it can be input manually by the user.

Step 2. Fraction of gas sent to the CCP plant

- Column B: Enter the fraction of gas sent to the CCP plant

Step 3. Calculation of exportations

- Column C: Auto-calculated value of fossil CO₂ that is exported to CCP plants.

Note: In case the option “Assignment of Combustion Units to the PCC Plant” is selected in the worksheet “Direct – Stationary Combustion Sources” and later on the item is eliminated, the value calculated in the page “CO₂ Importations and Exportations” must be erased.

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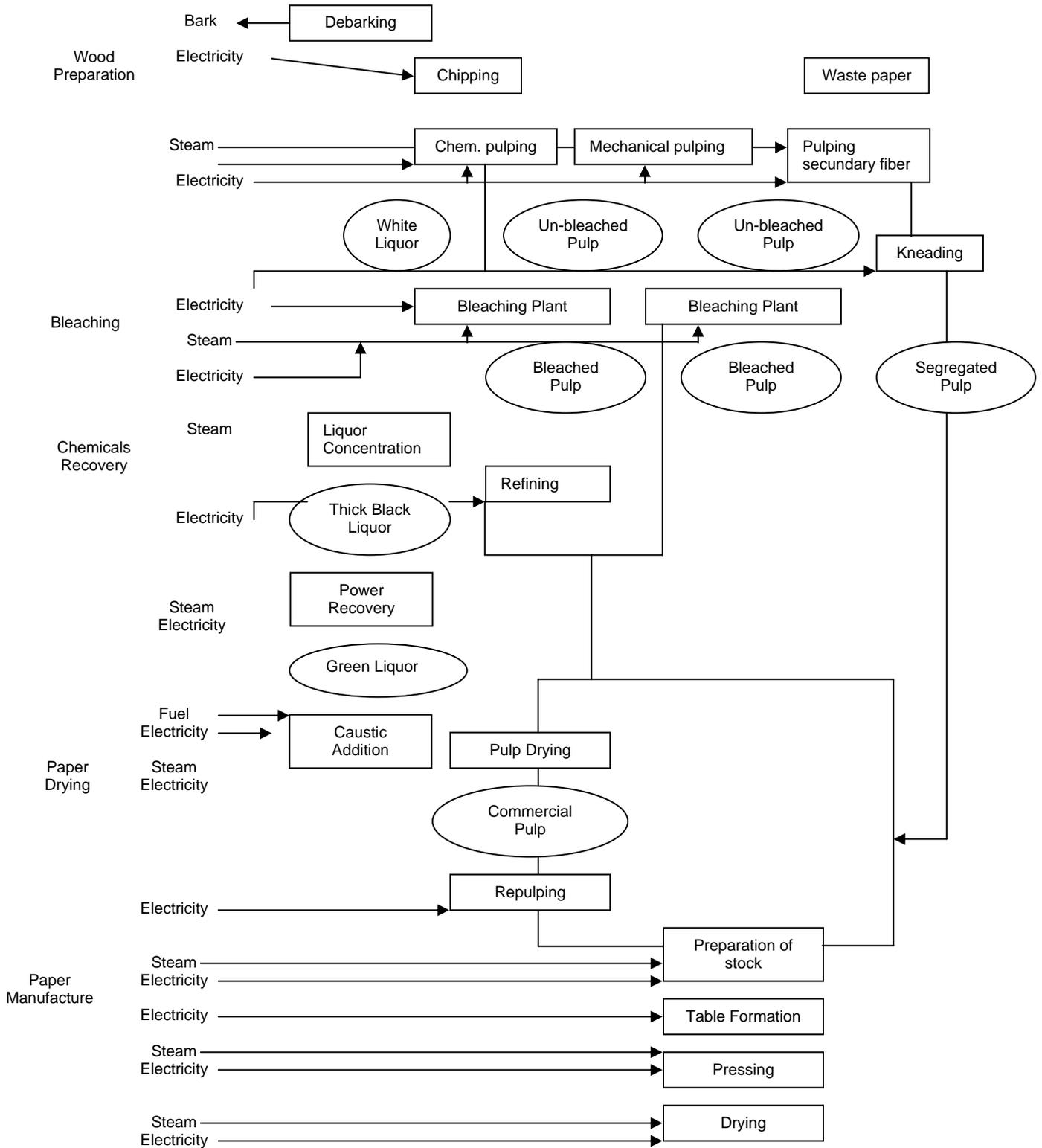
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Annex 1. Pulp and Paper

Figure A.1 Pulp and Paper Manufacturing Process



A.1 Description of Pulp Manufacture

World-wide, the most used pulp manufacturing process is through the use of chemicals. In Mexico, chemical pulp production represented 91.1% of the total during 1999.

A.1.1 Chemical Pulp

Of the alkaline processes for pulp production from wood, the one known as sulfate or "Kraft" is the most used in Mexico (55.3% of pulp in Mexico was obtained by this process during 1999).

In the first stage of the process, the wood is chipped and screened, before going to the digestion tank, where a series of very complex chemical reactions take place.

When digestion has finished, the main products consist of a raw pulp brown in color and black liquor. The black liquor is a complex mixture of organic material and unspent chemicals. The economy of this pulping process depends, to a great extent, on an adequate chemical recovery system during the digestion stage.

The black liquor and pulp are separated by means of filtration and washing operations. As part of the operations described above, a series of by-products are recovered, such as turpentine, bogol oil, soap, tar, etc. Steam is used in this part of the process and CO₂ emissions are produced from stationary sources that use fossil fuels.

Raw pulp goes through a series of important operations for cleansing and whitening. Power and steam consumption during the whitening stage depends on the type of technology used. Pulp is first screened and washed with water, then filtered and washed again, according to the degree of brightness needed, which depends on the use that will be given to it.

It should be mentioned that when factories only produce pulp paste, a drying process is required. Pulp drying is intensive, thus large amounts of electrical power and steam are consumed, which produces CO₂ emissions from steam generating boilers.

A.1.2 Mechanical Pulping Process

This process consists in reducing wood to its fibrous state through entirely mechanical means; that is, without using chemicals. This process includes crushing the wood in water until a fibrous paste is obtained, using a carborundum stone. In this mill, the soft wood chips are forced against the mortar, which works almost the same as a grinding stone. By rotating, it turns the wood into its fibrous components; the paste thus formed is pulled out of the mill with flowing water that is sprayed on the stone surface, which at the same time absorbs the heat generated by friction. The paste obtained is cleansed in centrifugal screens and sent to a whitening operation where it is treated with a zinc hydrosulfite solution.

A.1.3 Chemical Thermo Mechanical Process

This type of pulping is started by introducing the raw material cellulose, sugar cane baggase or wood chips in a hopper, which discharges to a screw feeder. Said feeder has the purpose of forcing the cellulose material into a digester tube, which is pressurized by the addition of soda ash/sodium sulfite so that when it goes through the digester it will

produce a moderate break-down of the lignin in the wood baggase. Simultaneous addition of steam and chemicals leads to requiring less power in the fiber removal stage of the process. The softened paste that leaves the digester is washed and cleansed to then be sent to fiber removal in a double disk tandem refiner. Raw pulp can be laminated for sale or whitened using hydrogen peroxide, depending on the market. At this stage, CO₂ emissions are also produced through burning fossil fuels to generate the steam used in the process.

2.2 Paper Manufacture

A.2.1 Paper Process

Due to the great variety of types of paper that can be manufactured, it would be not be possible to mention all of them. However, in a general manner, it can be said that paper manufacture consists mainly of mechanical operations, which are based on the tendency of cellulose fibers in a water suspension to unite when they dry. The manufacturing process takes place in two large areas; the first refers to the preparation of paste, while the second has to do with paper formation in itself.

A.2.2 Paper Formation

The continuous paper making machine converts a very dilute fiber suspension into a dry sheet at a relatively high speed. The Fourdrinier machine or flan table consists basically in an endless screen, which runs at speeds between a tenth of a meter and about 1,500 meters per minute. At one end of the screen, under laminar conditions, the fiber suspension is deposited, which has been polished during the previous phase to obtain the fiber stock with a consistency of about 0.8% (fiber content in solution). As the suspension advances through the machine, it loses water, simultaneously giving rise to the enmeshment of the fibers that make up the sheet of paper.

The dewatering operation takes place when the screen goes over suction boxes and table rollers, located in the forming section of the machine. At the opposite end of the screen, the sheet of paper comes out with still too much water at about 20%, approximately. Hence, it is made to go through a series of presses by means of a wool felt band, where it loses more water in a mechanical manner.

In order to increase the evaporation capacity of the drying section, it is normal to use a series of gas burners, which allow blowing ambient air at high temperatures. Power and steam consumption during drying is relatively high, thus, CO₂ emissions are also produced during this step.

Annex 2. Inventory Operational Limits

A 2.1. Example of a Table to Report Operational Boundaries of the Inventory

This matrix may be used to indicate which operations are included within the boundaries of the inventory and their ownership. Provide a general description of the boundaries, any additional information needed to explain them and then put an "X" in appropriate boxes.

Use this space to provide additional information helpful to understanding the operational boundaries of the inventory, including the method used to allocate emissions from partly-owned or partly-controlled sources. <i>Attach additional pages if needed.</i>	Mark with a "X" to identify operations included in the inventory
Harvesting	
Wood/chip/bark/wastepaper/other raw material transportation vehicles	
Product, by-product or waste transportation vehicles	
Debarking	
Chipping	
Mechanical Pulping	
Chemical Pulping – Kraft	
Chemical Pulping – sulfite	
Chemical Pulping – other	
Semi-chemical Pulping	
Recovery furnace	
Liquor furnace– sulfite	
Liquor furnace – Semi-chemical	
Lime kiln or calciner	
Incinerators for non-condensable gases, etc.	
Wastepaper pulping and cleaning	
Bleaching of chemical or semi-chemical pulp	
Brightening of deinked pulp	
On site preparation of chemicals (ClO ₂ o O ₃)	
Paper and/or paperboard production	
Coating (including extrusion coating)	
Roll trimming, roll wrapping, sheet cutting	
On-site power and steam boilers	
On-site combustion turbines	
Gas-fired infrared dryers	
Other fossil fuel-fired dryers	
Wastewater treatment operations	
Sludge processing	
Landfill receiving mill waste	
Air emissions control devices	
On-road vehicles	
Of-road vehicles and machinery	
Normal offices/ workspace for mill employees	
Other operation – describe:	
Other operation – describe:	
Other operation – describe:	

Annex 3. Heating Values of Mexican Fuels

A3. Net heat values for fuels used in Mexico				
Fuel	Units	2000	2001	2002
Associated natural gas ^α	(kJ/m ³)	40,273	40,441	40,474
Non associated natural gas ^β	(kJ/m ³)	32,326	32,762	33,030
Thermal Coal ^λ	(MJ/t)	19,136	18,796	19,405
National steel making coal	(MJ/t)	23,483	23,483	23,483
Electrical power primary equivalent	MJ/MWh	10,407	10,263	10,420
Maya crude oil	MJ/bl	6,143	6,143	5,658
Istmo crude oil	MJ/bl	5,628	5,628	5,983
Olmecca crude oil	MJ/bl	5,700	5,700	5,543
Natural Gasolines	MJ/bl	4,781	4,781	4,781
Petroleum Coke	MJ/t	31,672	29,631	30,675
Liquified Gas	MJ/bl	3,734	3,734	3,734
Gasolines and naphthas	MJ/bl	5,126	5,051	5,051
Kerosene	MJ/bl	5,665	5,602	5,602
Diesel	MJ/bl	5,729	5,561	5,561
Fuel oil	MJ/bl	6,392	6,392	6,392
Lubricants	MJ/bl	6,029	6,029	6,800
Greases	MJ/bl	5,967	5,967	5,967
Natural Gas ^δ	kJ/m ³	33,427	33,913	33,913
Propane-propylene	MJ/bl	4,069	4,069	4,069
Butane-butyene	MJ/bl	4,069	4,069	4,069
Natural gas for export	kJ/m ³	35,424	33,913	35,707
Imported natural gas	kJ/m ³	34,478	33,913	34,599
International thermal coal	MJ/t	18,360	23,981	25,284
International steel coal	MJ/t	29,559	29,559	29,559
Coke from coal	MJ/t	26,521	26,521	26,521
Wood ^ε	MJ/t	14,486	14,486	14,486
Sugar cane baggase	MJ/t	7,055	7,055	7,055

Source: Balance Nacional de Energía 2003

^α Associated Natural Gas is measured at the exit of separation batteries, standard at 20°C and 100 kPa. RI natural gas at the exit of the well has a heat value of 45,225 kJ/m³.

^β Non associated natural gas is measured under Standard conditions; heat value at the well head is 38,073 kJ/m³.

^λ In the case of heat value for thermal coal at power stations is considered a mixture of national with imported of 19,915 MJ/t for 2001 and 21,685 MJ/t for 2002.

^δ Corresponds to volumes measured at 20°C and 100 kPa of pressure, the value of residual fractured gas is 35,420 kJ/m³

^ε Air dried wood with 25.0 percent humidity

Annex 4. Emission Factors for CH₄ and N₂O from Biomass Combustion

A4. Emission Factors for CH ₄ y N ₂ O from Burning Biomass			
<i>Wood waste – fired boilers</i>			
Description of Emission Factors	kg CH ₄ /TJ	kg N ₂ O/TJ	Reference
Wood, wood waste, and other biomass and waste	30	4	Tier 1- IPCC 1997c
Uncontrolled emissions from wood-fired stoker boilers	15	-	Tier 2-IPCC 1997c
Average for wood residue combustion	9.5	5.9	USEPA 2001
Average for circulating fluidized bed boilers burning peat or bark	1	8.8	Fortrum 2001
Average for bubbling fluidized bed boilers burning peat or bark	2	<2	Fortrum 2001
Pre-1980 wood residue-fired stoker boilers sampled ahead of control devices	8.2.	-	NCASI 1980
Pre-1980 wood residue-fired stoker boilers sampled after wet scrubbers	2.7	-	NCASI 1995
Wood fired boiler	41	3.1	JPA 2002
Wood as fuel	24	3.4	AEA Tech. 2001
Wood waste	30	5	Swedish EPA 2004
Median emission factors for wood waste	12	4	
	1 - 40	1.4 - 75	EEA 2004
<i>Recovery furnaces</i>			
Recovery furnace	<1	<1	Fortrum 2001
Recovery furnace – black liquor	2.5	-	JPA 2002
Black Liquor	30	5	Swedish EPA 2004
Median emission factors for black liquor	2.5	2	
	1 – 17.1	1 –21.4	EEA 2004

Annex 5. Emission factors and methods for estimating GHG and SO₂ emissions from stationary sources

Fossil Fuel	Uncorrected Emission Factor kg CO ₂ / TJ *	Corrected Emission Factor kg CO ₂ / TJ
Crude Oil	73,700	72,600
Gasoline	69,300	68,600
Kerosene	71,900	71,200
Diesel Oil	74,100	73,400
Waste fuel Oil	77,100	76,600
LPG	63,100	62,500
Petroleum Coke	100,800	99,800
Anthracite coal	98,300	96,300
Bituminous coal	94,600	92,700
Sub-bituminous coal	96,100	94,200
Lignite	101,200	99,200
Peat	106,000	104,900
Natural Gas	56,100	55,900

* These factors assume no un-oxidized carbon. To account for un-oxidized carbon, IPCC suggests multiplying by these default factors: coal = 0.98, oil = 0.99, and gas = 0.995.

Source	Coal	Oil	Natural Gas
IPCC (1997c)	98%	99%	99.5%
Environment Canada (2004)	99%	99%	99.5%
EPA Climate Leaders (USEPA 2003)	99%	99%	99.5
DOE 1605b (USDOE 1994)	99%	99%	99%
EPA AP-42 (USEPA 1996, 1998, a, b, c)	99%	99%	99%

Rank	Description	Resolution
Preferred	Calculation based on fuel consumption data (or other activity data) disaggregated by specific fuel types and combined with site or equipment-specific emission and control efficiency/utilization factors	Combustion Units
Default	Calculation based on aggregate fuel consumption data (or other activity data) combined with generic default emission	Corporate or business unit

A 5.4. IPCC Tier 1 CH₄ and N₂O Emission Factors for Stationary Combustion (from IPCC 1997c)

Fuel	CH ₄ Emission Factor kg/TJ	N ₂ O Emission Factor kg/TJ
Coal	10	1.4
Natural Gas	5	0.1
Oil	2	0.6
Wood/wood residuals	30	4

A.5.5. IPCC Tier 2 Uncontrolled CH₄ and N₂O Emission Factors for Industrial Boilers (IPCC 1997c)

Fuel	Technology	Configuration	kg CH ₄ /TJ	kg N ₂ O/TJ
Bituminous coal	Overfeed stoker boilers		1.0	1.6
Sub-bituminous coal	Overfeed stoker boilers		1.0	1.6
Bituminous coal	Underfeed stoker boilers		14	1.6
Sub-bituminous coal	Underfeed stoker boilers		14	1.6
Bituminous coal	Pulverized	Dry bottom, wall fired	0.7	1.6
Bituminous coal	Pulverized	Dry bottom tang. Fired	0.7	0.5
Bituminous coal	Pulverized	Wet bottom	0.9	1.6
Bituminous coal	Spreader stoker		1.0	1.6
Bituminous coal	Fluidized bed	Circulating or bubbling	1.0	96
Sub-bituminous coal	Fluidized bed	Circulating or bubbling	1.0	96
Anthracite			10*	1.4*
Residual Oil			3.0	0.3
Distillate Oil			0.2	0.1*
Natural Gas	Boilers		1.4	0.1*
Natural Gas	Turbines		0.6	0.1*
Natural Gas	Int. comb. Engine	2 cycle – lean burn	17	0.1*
Natural Gas	Int. comb. Engine	4 cycle – lean burn	13	0.1*
Natural Gas	Int. comb. Engine	4 cycle – rich burn	2.9	0.1*

* These are IPCC Tier 1 generic emission factors for coal and natural gas. Tier 2 emission factors are not available.

A 5.6. Specific Emission Factors for SO ₂	
Fuel	Emission Factor kg SO ₂ /10 ⁶ kcal
Fuel oil with 1% sulfur by weight	2.04
Fuel oil with 2% sulfur by weight	4.08
Fuel oil with 4% sulfur by weight	8.16
Diesel with 0.5% sulfur by weight	0.91

Source: NOM-085-ECOL-1994

A 5.7. Emission factors for sulfur dioxide (SO ₂) in Mexican vehicular transportation	
Fuel	Emission Factor (kg SO ₂ /TJ)
Fuel oil	1834.02
Diesel (National)	457.98
Diesel (sweetened)	228.99
Diesel (SIN)	22.90
Gasoline (Nova)	67.39
Gasoline (PEMEX-Magna Rest of country)	44.92
Gasoline (PEMEX- magna metropolitan areas)	22.46
Gas (Liquefied)	5.92

Source: Inventario Nacional de Gases de Efecto Invernadero 1997-1988

A 5.8. Default Values for Sulfur Content (s) in Mexican Fuels		
Fuel	Maximum level of sulfur (wt %)*	
Magna Sin	0.10	
Magna Sin: Northern Border Zone - ZFN	0.10	
Magna Sin: Mexico City Metropolitan Zone (ZMCM), after 1998, also in the Monterrey Metropolitan Zone (ZMM) and Guadalajara Metropolitan Zone (ZMG)	0.1	
Nova Plus	0.15	
Nova Plus: ZMCM and after 1998 also in the ZMM and ZMG	0.15	
Diesel Sin: ZMCM, ZMM and ZMG	0.05	
Diesel Sweetened	0.5	
Diesel Industrial	0.5	
Light Fuel Oil (Industrial)	2.0	
Heavy Fuel Oil	4.0	
Hydrated Fuel Oil: ZMCM after 1998	1.0	
Light fuel for critical zones (ZMCM, ZMM y ZMG)	2.0	
Natural Gas	0	
Liquefied Petroleum Gas (LPG)	0.01	
Turbosine	0.3	
Coal ^φ	Thermal (MICARE-Río Escondido)	0.90
	Thermal imported	1
	Steel making (coke)	1.39

Adapted from the Manual de Inventario de Emisiones, Volumen V and the Balance Nacional de Energía 2003

^φ Values obtained from BNE 2002

A 5.9. Default Values for Sulfur Content (s) in Fuel (IPCC, 1996)	
Fuel	Default Value (%)
Jet Kerosene	0.05
Black Liquor	1.5
Fuel Wood	0.2
Other biomass	<0.03

Source: 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual

A 5.10 Default Values for the Sulfur Retention (r) in Ash [%]	
Fuel	r (%)
Hard coal	5
Brown coal	30

Source: 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual

A.5.11 Emission Factors for Kraft Mill Lime Kilns and Calciners						
Fuel	Kraft mill lime kilns			Kraft mill calciners		
	CO ₂	CH ₄	N ₂ O	CO ₂	CH ₄	N ₂ O
Waste oil	76,600	2.7	0	76,600	2.7	0.3
Destillate oil	73,400	2.7	0	73,400	2.7	0.4
Natural Gas	55,900	2.7	0	55,900	2.7	0.1
Biogas	0	2.7	0	0	2.7	0.1

A 5.12 Emission Factors for Off-Road Mobile Sources and Machinery (IPCC 1997 c)				
Source and Engine type	CO ₂ kg/TJ	CH ₄ kg/TJ	N ₂ O kg/TJ	CO ₂ eq. kg/TJ
Forestry - diesel	73,400	4	30	82,800
Industry - diesel	73,400	4	30	82,800
Railways – diesel	73,400	4	30	82,800
Inland waterway – diesel	73,400	4	30	82,800
Marine – diesel	73,400	7	2	74,200
Industry – gasoline 4-stroke	68,600	50	2	70,300
Forestry – gasoline 2 stroke	68,600	170	0.4	72,300
Industrial – gasoline 2 stroke	68,600	130	0.4	71,500
Inland waterway – gasoline 4 stroke	68,600	40	2	70,100
Inland waterway – gasoline 2 stroke	68,600	110	0.4	71,100

In Mexico, emission factors for vehicles are limited to a few developed by the Mexican Petroleum Institute (IMP). These factors were developed for an experimental flotilla in Mexico City, hence it is recommended that the EFs from the previous table be used.

A 5.13. Emission factors for Mexican vehicle transportation		
Vehicle	CH ₄ (g/km)	N ₂ O (g/km)
Vehicles without emission controls		
Private Automobiles	0.174	0.005
Light trucks - gasoline	0.174	0.006
Heavy trucks - gasoline	0.174	0.009
Motorcycles	0.329	0.002
Heavy trucks - diesel	0.100	0.031
Light Vehicles - liquefied gas	0.180	>>>
Heavy Vehicles - liquefied gas	0.400	>>>
Vehicles with emission controls		
Light trucks - gasoline	0.070	0.046
Heavy trucks - gasoline	0.080	0.063
Motorcycles	0.100	0.006
Heavy trucks - diesel	0.329	0.002
Light Vehicles - liquefied gas	0.030	0.025
Heavy Vehicles - liquefied gas	0.030	>>>
Light trucks - gasoline	0.150	>>>

Annex 6. Emission Factors from Make-up Chemicals

A6. Emissions from Calcium Carbonate and Sodium Carbonate Make-Up in the Pulp Mill*	
Compound	Emissions
Pulp Mill make-up CaCO ₃	440 kg CO ₂ /t CaCO ₃
Pulp Mill make-up Na ₂ CO ₃	415 Kg CO ₂ / t Na ₂ CO ₃

*If the carbonate is derived from biomass, GHG emissions are zero.

Annex 7. Emission Factors for Imported Electricity

A7. Electrical GHG Emission Factors Suggested by ATPAE (Historic 1995-2001) (tCO ₂ eq./MWh)					
Year	Interconnected System	Northwest System	Baja California System	Baja California Sur System	All the National Electrical System
1995	0.6341	0.6911	0.6673	0.7810	0.6273
1997	0.6317	0.6171	0.6810	0.7877	0.6263
1998	0.6401	0.6029	0.6913	0.8228	0.6332
1999	0.6378	0.6247	0.7029	0.8172	0.6301
2000	0.6380	0.6244	0.6627	0.8232	0.6612
2001	0.6521	0.6157	0.6029	0.8085	0.6539

Source: ATPAE

A 7.1. GHG Emission Factors projected to the future to year 2010 (tCO ₂ eq./MWh)				
Year	Interconnected System	Northwest System	Baja California System	Baja California Sur System
2002	0.6312	0.6157	0.6029	0.8085
2003	0.5827	0.6131	0.5199	0.8085
2004	0.5583	0.6611	0.5199	0.7686
2005	0.5546	0.6611	0.5199	0.7686
2006	0.5468	0.6611	0.4987	0.7685
2007	0.5288	0.6619	0.4992	0.7694
2008	0.5368	0.6126	0.5104	0.7866
2009	0.5487	0.5955	0.5238	0.8009
2010	0.5285	0.5677	0.5187	0.7466

Source: ATPAE

The EFs for 2002 and 2010 are not yet officially recognized, but are a good reference for estimating GHGs from electrical power consumption.

Annex 8. Presenting Results

A 8.1 Example of a Table to Report GHG Inventory Results – Scope 1 (Direct Emissions) <i>emissions from sources that are wholly or partially owned or controlled by the company</i>					
Where emissions have been determined to be insignificant or nonmaterial, write “NM” and explain the basis for the determination in a footnote.		Total Scope 1 Metric tons			
		CO ₂	CH ₄	N ₂ O	CO ₂ ⁹ Equiv
	<i>Process and Energy-Related Emissions</i>				
1	Stationary Fossil Fuel Combustion				
2	Biomass Combustion	N/A*			
3	Make-up Chemicals (CaCO ₃ and Na ₂ CO ₃)				
	<i>Transportation and machinery emissions</i>				
4	On-road vehicles				
5	Off-road vehicles and machinery				
	<i>Waste management emissions</i>				
6	Anaerobic wastewater treatment systems	N/A*			
7	<i>Other Direct Emissions not included in Scope 1 above – Explain:</i>				
	Total Emissions Scope 1 (Sum of lines 1 through 7)				
<i>Emissions associated with exported electric power and steam (a subset of total direct emissions)</i>					
8	Emissions related to electric power exports (kg CO ₂ /MWh)				
	Carbon intensity of electric power exports (kg CO ₂ /MWh)				
	Method used to estimate GHG intensity of grid:				
9	Emissions related to steam exports				
10	<i>Total emissions attributable to exports (Sum of lines 8 and 9)</i>				
<p>Explain the method used to determine ownership/control of sources not completely owned by the company. A protocol such as the WRI/WBCSD GHG Protocol can be used for guidance on determining ownership/control.</p> <p>Include any other information that is needed to understand the inventory results.</p>					

*N/A – Not Applicable - carbon dioxide emissions from biomass are not included in GHG totals because this carbon is considered part of the natural cycle; i.e., it is recycled between the atmosphere and plant tissue.

⁹ CO₂-equivalents are calculated multiplying individual gases by IPCC GWP values, CO₂=1, CH₄=21, N₂O=310, and summing across all three gases. It is acceptable to use emission factors for CO₂-equivalents rather than estimating the three gases individually.

A 8.2 Example of a Table to Report GHG Inventory Results – Scope 2 (Indirect Emissions) <i>emissions attributable to power/steam imports, and imports/exports of fossil-CO₂</i>					
Where emissions have been determined to be insignificant or nonmaterial, write “NM” and explain the basis for the determination in a footnote.		Total Scope 2 metric tons			
		CO ₂	CH ₄	N ₂ O	CO ₂ ¹⁰ Equiv
<i>Scope 2- Indirect emissions related to electric power and steam imports</i>					
1	Scope 2 – Indirect Emissions related to electric power imports that are consumed				
2	Scope 2 – Indirect Emissions related to steam imports that are consumed				
3	<i>Total indirect emissions from power/steam imports (Sum of lines 1 through 2)</i>				
<i>Other Indirect Emissions (Scope 3)</i>					
4	Description of other indirect emissions included in inventory:				
<i>Imports and Exports of fossil fuel-derived CO₂</i>					
5	Imports of CO ₂ (e.g., for neutralization)				
6	Exports of fossil fuel-derived CO ₂ (e.g., to PCC Plants) Note 1: This includes only the fraction of CO ₂ exports that can be traced to fossil fuels. Exports of biomass-derived CO ₂ are reported in Table A 8.4 – CO ₂ emissions derived from Biomass. Note 2: This exported CO ₂ should <i>not</i> be reported as an emission in Table A 8.1.				
Explain the method used to determine ownership/control of sources not completely owned by the company. A protocol, such as the WRI/WBCSD GHG Protocol, can be used for guidance on determining ownership/control.					
Include any other information needed to understand the inventory results:					

¹⁰ CO₂-equivalents are calculated multiplying individual gases by IPCC GWP values, CO₂=1, CH₄=21, N₂O=310, and summing across all three gases. It is acceptable to use emission factors for CO₂-equivalents rather than estimating the three gases individually



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