GREENHOUSE GAS PROTOCOL

GHG Protocol Scope 2 Guidance

An amendment to the GHG Protocol
Corporate Standard

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1 Introduction

The Greenhouse Gas (GHG) Protocol is a multistakeholder partnership of businesses, nongovernmental organizations (NGOs), governments, and others convened by the World Resources Institute (WRI) and the World Business Council for Sustainable Development (WBCSD).

Launched in 1998, the GHG Protocol seeks to develop internationally accepted GHG accounting and reporting standards and tools to promote their adoption worldwide. To date, the GHG Protocol has released four standards that address how GHG emissions inventories should be prepared at the corporate, project, and product levels.

1.1 The GHG Protocol

- **Corporate-level.** The *GHG Protocol Corporate Accounting and Reporting Standard* (*Corporate Standard*) outlines a standard set of accounting and reporting rules for developing corporate inventories. The *Corporate Standard* identifies and categorizes the emissions from all of the operations that together comprise an organization (the term "company" is used to represent all types of organizations using the *Corporate Standard* and this *Scope 2 Guidance*).

  Building from the *Corporate Standard*, the *GHG Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard* provides additional requirements and guidance on developing comprehensive inventories of other indirect (scope 3) emissions.

- **Project-level.** The *GHG Protocol for Project Accounting* (*Project Protocol*) describes how companies can quantify the GHG impacts of specific projects undertaken to reduce emissions, avoid emissions occurring in the future, or sequester carbon.

- **Product-level.** The GHG Protocol *Product Life Cycle Accounting and Reporting Standard* (*Product Standard*) describes how companies can develop GHG emissions inventories, including the entire life cycle of individual products or services—from raw material extraction to product disposal.

These publications, together with supplementary guidance for specific sectors or types of sources, are available from the GHG Protocol website (www.ghgprotocol.org).

1.2 The *Corporate Standard*'s approach to scope 2 emissions

The *Corporate Standard* requires organizations to quantify emissions from the generation of acquired and consumed electricity, steam, heat, or cooling (collectively referred to as "electricity"). These emissions are termed "scope 2" and are considered an indirect emissions source (along with scope 3), because the emissions are a consequence of activities of the reporting organization but actually occur at sources owned or controlled by another organization (here, they are owned or controlled by an electricity generator or utility).

Scope 2 represents one of the largest sources of GHG emissions globally: the generation of electricity and heat now accounts for at least a third[1] of global GHG emissions. Electricity consumers have significant opportunities to reduce those emissions by reducing electricity demand, and increasingly play a role in shifting energy supply to alternative low-carbon resources.

The methods used to calculate and report scope 2 emissions critically impact how a company assesses its performance and what mitigation actions are incentivized. To calculate scope 2 emissions, the *Corporate Standard* recommends multiplying activity data (MWhs of electricity consumption) by source and supplier-specific emission factors to arrive at the total GHG emissions impact of electricity use. It also emphasizes the role of green power programs in reducing emissions from electricity use.[2] Only if these forms of information about electricity supply are unavailable are companies advised to use statistics such as local or national grid emission factors.

1.3 Key questions on scope 2 accounting and reporting

Since the publication of the *Corporate Standard* revised edition, companies and their stakeholders identified conceptual and technical challenges with the existing recommendations on scope 2 accounting and reporting, including the fundamental question:

- **How should renewable energy purchases be reflected in scope 2 reporting?** Previously, some companies (particularly in the U.S.) adjusted their scope 2 emissions by using an estimate of the avoided fossil fuel emissions from the grid associated with their purchase of renewable energy certificates (RECs) and deducting this from their scope 2 total calculated by grid-average emission factors. Others treated purchases as an emission factor conveying a "zero emission rate" in scope 2 calculations rather than using avoided grid emissions. Still others treated participation in green power programs effectively as a donation, with no impact on the GHG inventory. The variety of accounting methods made it difficult for a company to consistently account and report scope 2 emissions across multiple countries.

Underlying this accounting and reporting question were three main types of questions, relating to:

Instruments

- **What constitutes a renewable energy purchase?** In several countries and energy markets around the world, new instruments have been developed to track energy production information (or its "attributes") separately from actual energy delivery. These instruments—termed here "energy attribute certificates"—typically flow from energy generation facilities to energy suppliers and ultimately energy consumers in order to support consumer claims about the type of energy used and its related attributes—such as GHG emissions—produced at the point of generation.

  Some certificates, such as the Guarantee of Origin (GO) in Europe, were envisioned as a way to support energy supplier disclosure and inform consumer choice as energy markets were liberalized. The renewable energy certificate (REC) in the United States and Canada serves a regulatory role in states with renewable energy supplier quotas, as well as a voluntary role for consumers who want to purchase and support renewables. The *Corporate Standard* did not state which of these types of instruments could be appropriate for a scope 2 consumer claim, or whether other types of contractual instruments—such as direct contracts with a renewable energy generator—could fulfill a similar role.

- **What is included in a supplier-specific emission factor?** Electricity suppliers compile emission rates for a variety of purposes. Some supplier emission rates may reflect only the emissions from utility-owned assets, while others also reflect power purchased by the utility from an independent energy generation facility. Many green power programs have been offered directly by utilities, segmenting different emission rates for different consumer classes. Supplier disclosure requirements and calculation methodology differ, making it difficult for consumers to consistently use this type of information.

- **How comparable are green power programs?** Companies operating in multiple countries identified differences in the eligibility criteria used in different green power products—that is, the specifications regarding the age of a generation facility, the type of technology, whether it received public subsidy or was entirely funded by voluntary purchases, etc. While these differences do not impact the actual GHG emission rate from energy production represented in the green power product, they may matter for companies with other environmental or social goals associated with their energy procurement.

Concept

- **How can a company claim to use only renewable energy if it uses inherently untraceable grid-distributed energy?** Most energy grids provide energy for hundreds of thousands of consumers over the course of a day with a blend of energy generation facilities, including a heavy share of fossil fuel plants in most grids. By design, energy attribute certificates like RECs and GOs are separate from the physical distribution of energy. They act as a tool to convey claims and influence market dynamics by allowing the expression and aggregation of consumer preferences for specific low-carbon energy products, which would not otherwise be possible. Consumers cannot choose what energy is generated on their grid at a given point in time, but contractual instruments allow for energy attributes such as GHG emissions to be allocated along the lines of contractual relationships among producers, suppliers, and consumers.

- **If green power is used by some companies, how does that impact the emissions reported by other consumers?** The *Corporate Standard* does not address potential double counting between consumers of emissions associated with green power instruments. But implementing a credible and robust system for GHG emission rate calculation and claims based on contractual instruments—such as GOs, RECs, or supplier-specific emission rates—would require that only one consumer reports the emissions from a given quantity of generation.

Impact on global emissions

- **Do green power programs directly or indirectly reduce GHG emissions over time?** Emissions from a grid region decrease over time due to a combination of lowered energy demand and changes in supply to lower-emitting facilities. The *Corporate Standard* acknowledges that linking consumer behavior and choices with a grid system's emissions is complex and nonlinear.[3] When it comes to green power products, a single company's purchase via a supplier or through a direct contract may not itself change overall grid emissions at the time of purchase. This is because most green power products are based on instruments from existing energy generation facilities. Most voluntary green power programs are designed to translate consumer demand for certain types of energy into changes *over time* in the supply of that energy. When demand increases, it pushes up the price of these attributes, therefore creating an incentive to expand the supply of low-carbon generation facilities. Whether a market for attributes actually results in new low-carbon supply depends on several factors, including the level of consumer demand and the supply of attributes available.[4]

The lack of clear and consistent guidance on these questions created uncertainty about emission reduction strategies and prevent company inventories from reflecting a true and fair account of emissions.

1.4 Purpose of this Guidance

This guidance acts as an amendment to the *Corporate Standard,* providing updated requirements and best practices on scope 2 accounting and reporting. It aims to answer the questions articulated in section 1.3. The revisions in this guidance should enhance the relevance, completeness, consistency, transparency, and accuracy of reported scope 2 totals. Companies can use these reported totals to set targets, reduce GHG emissions, track progress, and inform their stakeholders.

1.5 Guidance overview

This guidance codifies two distinct methods for scope 2 accounting, each with a list of appropriate emission factors. Both methods are useful for different purposes; together, they provide a fuller documentation and assessment of risks, opportunities, and changes to emissions from electricity supply over time.

A *location-based method* reflects the average emissions intensity of grids on which energy consumption occurs (using mostly grid-average emission factor data). A *market-based method* reflects emissions from electricity that companies have purposefully chosen (or their lack of choice). It derives emission factors from contractual instruments, which include any type of contract between two parties for the sale and purchase of energy bundled with attributes about the energy generation, or for unbundled attribute claims. Markets differ as to what contractual instruments are commonly available or used by companies to purchase energy or claim specific attributes about it, but they can include energy attribute certificates (RECs, GOs, etc.), direct contracts (for both low-carbon, renewable, or fossil fuel generation), supplier-specific emission rates, and other default emission factors representing the untracked or unclaimed energy and emissions (termed the "residual mix") if a company does not have other contractual information that meets the Scope 2 Quality Criteria.

See Box 1.1 for an overview of key terms related to scope 2 in this guidance.

1.5.1 New reporting requirements

Companies with any operations in markets providing product or supplier-specific data in the form of contractual instruments **shall** report scope 2 emissions in two ways and label each result according to the method: one based on the location-based method, and one based on the market-based method. This is also termed "dual reporting."

Not having contractual data for every site will not cause noncompliance with the GHG Protocol *Corporate Standard* and *Scope 2 Guidance*. As with scope 3, a range of data may be available. Companies should consult the hierarchy of emission factors for both location-based and market-based methods. Any data on those hierarchies (including using location-based emission factors in the absence of contractual information) is acceptable.

1.5.2 Scope 2 Quality Criteria for the market-based method data

To make the market-based method globally consistent and capable of producing accurate results, this guidance establishes required Scope 2 Quality Criteria that all contractual instruments must meet. These Scope 2 Quality Criteria are policy-neutral and represent the minimum features necessary for instruments to function together as a complete market-based emission allocation system for consumers. Companies without contractual instruments that meet the Scope 2 Quality Criteria may use other emission factors (listed in Chapter 6).

1.5.3 Other disclosure

To encourage transparency and improve comparability of energy and energy attribute purchases from different markets, this guidance also recommends additional reporting disclosure about the energy generation features and policy contexts in which the purchase occurs. Separately disclosing total electricity, steam, heat, and cooling consumed per reporting period (in kWh, MWh, BTU, etc.) can also enhance transparency and clarify changes in consumption vs. changes in supply.

1.6 Who should use this Guidance?

This guidance acts as an amendment to the *Corporate Standard,* so all organizations compiling a corporate GHG inventory following the *Corporate Standard*—including companies, governments, NGOs, and other organizations—should use this guidance. The term "companies" is used throughout this document as shorthand for any organization compiling a corporate inventory.

In addition, energy suppliers, utilities, grid operators, and marketers offering voluntary green power programs providing product information to consumers should read this guidance to understand the type of information that customers may be requesting to calculate their scope 2 inventories following the market-based method.

Government entities involved in regulating energy and/or establishing frameworks and rules for consumer electricity choices should be informed about the requirements of this guidance. The relationships between regulatory programs (such as supplier quotas or public subsidies for renewable energy) and voluntary consumer programs are explored in Chapter 10.

Box 1.1 Key terms

Some terms used in this guidance are used for precision but are synonymous with other more familiar terms. For example:

Contractual instruments: Any type of contract between two parties for the sale and purchase of energy bundled with attributes about the energy generation, or for unbundled attribute claims. Markets differ as to what contractual instruments are commonly available or used by companies to purchase energy or claim specific attributes about it, but they can include energy attribute certificates (RECs, GOs, etc.), direct contracts (for both low-carbon, renewable, or fossil fuel generation), supplier-specific emission rates, and other default emission factors representing the untracked or unclaimed energy and emissions (termed the residual mix) if a company does not have other contractual information that meets the Scope 2 Quality Criteria.

Energy attribute certificate: A category of contractual instrument that represents certain information (or attributes) about the energy generated, but does not represent the energy itself. This category includes a variety of instruments with different names, including certificates, tags, credits, or generator declarations. For the purpose of this guidance, the term "energy attribute certificates" or just "certificates" will be used as the general term for this category of instruments.

Energy generation facility: Any technology or device that generates energy for consumer use, including everything from utility-scale fossil fuel power plants to rooftop solar panels.

Energy supplier: Also known as an electric utility, this is the entity that sells energy to consumers and can provide information regarding the GHG intensity of delivered electricity.

Generators: Here used to mean the entity that owns or operates an energy generation facility.

Green power product/green tariff: A consumer option offered by an energy supplier distinct from the "standard" offering. These are often renewables or other low-carbon energy sources, supported by energy attribute certificates or other contracts.

1.7 How should I use this Guidance?

This guidance replaces requirements and guidance on scope 2 in the *Corporate Standard.* It is divided into two parts:

- Chapters 1 through 9 provide requirements and practical recommendations on how to establish accounting boundaries, how to calculate emissions, and how to report emissions totals according to both methods in conformance with the guidance.
- Chapters 10 and 11 are optional background reading that addresses the broader concepts, principles, and examples of how energy markets worldwide have used contractual instruments to convey energy attributes (the basis of the market-based method). These chapters address how consumers can use their voluntary procurement power to accelerate the deployment of low-carbon energy to reduce overall emissions from the electricity system, while retaining the necessary instruments to make GHG claims in a market-based scope 2 total.
- Readers should also consult a supplemental compilation of case studies describing how a variety of organizations have implemented the new requirements of this Scope 2 Guidance. (Available at: ghgprotocol.org.)

The term "electricity" in this guidance is used to represent all purchased energy, but the guidance is primarily on electricity accounting. Appendix A indicates how these methods apply to heat/steam/cooling accounting as well.

1.7.1 Terminology: shall, should, may

This guidance uses precise language to indicate accounting and reporting requirements, recommendations, and allowable options that companies may choose to follow.

- The term **"shall"** is used throughout this document to indicate what is required in order for a GHG inventory to be in conformance with the *Scope 2 Guidance* and by extension the GHG Protocol *Corporate Standard*.

- The term **"should"** is used to indicate a recommendation, but not a requirement.
- The term **"may"** is used to indicate an option that is permissible or allowable.

The term "required" is used in the guidance to refer to requirements. "Needs," "can," and "cannot" may be used to provide recommendations on implementing a requirement or to indicate when an action is or is not possible.

1.8 How was this Guidance developed?

This guidance represents a policy-neutral, collaborative solution guided by GHG Protocol principles. It was developed over four years of international consultation and discussion with participation from businesses, NGOs, GHG reporting programs, energy utilities and retailers, renewable energy certification programs, government agencies, and scientific and academic institutions from around the world. It included:

- **Scoping Workshops.** From December 2010 to May 2011, WRI and WBCSD launched this process through a series of workshops in Washington, London, and Mexico City using short discussion drafts.
- **A Technical Working Group (TWG).** Formed in summer 2011, the TWG contributed to discussion papers, conference presentations, and draft proposals on accounting and reporting solutions. Discussion papers included topics such as:
  - Defining the principles of market-based systems: attributes, ownership, eligibility (Winter 2011)
  - Identifying objectives, background, and challenges with scope 2 accounting (Summer 2012)
  - Analyzing the relationship between indirect emissions accounting and system-wide reductions (December 2012)
- **Public Comment Period.** Draft guidance was made available for public comment from March 2014–May 2014, including six webinars and three in-person workshops in London, Dusseldorf, and Washington.

1.9 Changes from the *Corporate Standard*

This guidance introduces accounting and reporting requirements related to scope 2 that replace and add to those in the *Corporate Standard.* It also sets Scope 2 Quality Criteria that contractual instruments **shall** meet in order to be used in the market-based method. To prepare an inventory in conformance with the *Corporate Standard,* companies **shall** follow all new requirements in this guidance. These changes are summarized in Table 1.1.

1.10 Relationship to the GHG Protocol *Corporate Standard* and *Scope 3 Standard*

To prepare an inventory in conformance with the *Corporate Standard,* companies **shall** follow all new requirements in this *Scope 2 Guidance*.

In turn, the *Scope 3 Standard* intersects with scope 2 in several ways:

- The *Scope 2 Guidance* impacts how companies will communicate their scope 2 emissions to other value chain partners downstream and what type of scope 2 data they may receive from its value chain partners.
- The *Scope 2 Guidance* impacts how a company assesses the upstream emissions associated with its energy use (category 3—upstream energy emissions not recorded in scope 1 and 2, scope 3).

In both cases, a company **shall** disclose whether a market-based or location-based scope 2 total is used as the basis for calculating scope 3, category 3 (fuel- and energy-related emissions not included in scope 1 or scope 2).

Table 1.1 Additions to scope 2 accounting introduced by Scope 2 Guidance

Topic	How addressed in the *Corporate Standard*	How addressed in the *Scope 2 Guidance*
Obtaining activity data (kWh)	Consult utility bills.	No change from *Corporate Standard*, but additional guidance for on-site consumption and sales including net metering programs (see Chapter 5).
Disclosing activity data (kWh)	No requirement.	Companies should disclose total consumed electricity within inventory boundary.
Emission factors	Hierarchy presented starting with source and supplier-specific, and then grid average.	Two distinct methods of scope 2 accounting required, each with their own hierarchy of emission factors.
Green power programs—which instruments can count?	Example of a company, IBM, working with a local electricity supplier, Austin Energy, to purchase renewable energy to reduce scope 2 emissions.[a] Example of a utility, Seattle City Light, providing emission rate information to customers.[b] Example of a company, Alcoa, purchasing RECs in the U.S. to reduce emissions, based on an avoided emissions estimation and deduction accounting approach.[c]	Market-based method goes beyond just green power programs and recognizes a category of contractual instruments that should be used when calculating a market-based scope 2 result. These instruments may not be for green power or even renewable energy. They include: • Energy attribute certificates (GOs, RECs) • Direct contracts such as power purchase agreements (PPAs), where other instruments or energy attribute certificates do not exist • Supplier-specific emission rates • Residual mix (e.g., the emissions rate left after the three other contractual information items are removed from the system) Guidance provides global examples of each contractual instrument type provided.
Contractual instrument requirements	No requirements given.	All contractual instruments shall meet Scope 2 Quality Criteria to be used in the market-based method calculation. If they do not meet the Scope 2 Quality Criteria, then other data (listed in Table 6.3) shall be used as an alternative in the market-based method total. In this way, all companies required to report according to the market-based method will have some type of data option.
Accounting of green power purchases	No direct requirement, but example of U.S. avoided emissions calculation and deduction approachto RECs.[d]	Any type of energy or energy attribute purchase via a contractual instrument shall be treated in scope 2 like all other product information—an emission rate in tons GHG/unit of output (here, kWh) rather than an avoided emissions estimation and deduction. Companies then apply the emission factor derived from the contractual instrument to a quantity of energy consumption (activity data), consistent with the usage boundaries of that instrument.

Table 1.1 Additions to scope 2 accounting introduced by Scope 2 Guidance (continued)

Topic	How addressed in *Corporate Standard*	How addressed in Scope 2 Guidance
Reporting requirements	Report one scope 2 result in CO_2e, as well as by GHG.	If companies have any operations in markets providing product or supplier-specific data in the form of contractual instruments, then companies shall account and report scope 2 emissions in two ways and label each result according to the method: one based on the location-based method, and one based on the market-based method meeting Scope 2 Quality Criteria are met. If companies only have operations in markets without product or supplier-specific data, then only one scope 2 result shall be reported, based on the location-based method. Companies shall specify which method is used for goal-setting, tracking, and goal-achievement claims, and for scope 3 or product-level communication. Companies should disclose key features of contractual instruments, including any certification labels, characteristics of the energy generation facilities themselves, and policy context.

Notes:
[a] See *Corporate Standard* (WRI/WBCSD 2004), p. 14.
[b] See *Corporate Standard* (WRI/WBCSD 2004), p. 30.
[c] See *Corporate Standard* (WRI/WBCSD 2004), p. 63.
[d] See *Corporate Standard* (WRI/WBCSD 2004), p. 63.

1.11 What does this Guidance not address?

The market-based method codified in this guidance inherently requires systems for tracking and allocating electricity attributes from energy generators to end consumers. Most of these systems are formed by local or national policies, or interact closely with them. This guidance recognizes the role of these systems in providing information that meets the objectives of corporate GHG accounting: that is, reflecting the risks and opportunities associated with acquiring and consuming electricity and informing internal and external decisions to manage those emissions. However, like the *Corporate Standard*, this guidance is designed to be policy neutral. This means that it does not:

- Require the development of markets where none exist
- Make requirements or express preferences about the design of markets
- Address the non-GHG accounting aspects of energy policy or market-based accounting systems for consumers, including (a) social impacts and (b) financial costs or effectiveness relative to other policies at achieving specific climate abatement or other outcomes
- Define what should constitute "green" energy
- Identify "eligibility criteria" that would determine which types of electricity facilities should produce certificates or contractual instruments. The Scope 2 Quality Criteria in this Guidance relate to features required of the instruments themselves in order to support accurate accounting; the Criteria do not address which generation facilities should produce those instruments
- Promote specific energy generation technologies (such as renewable energy), or specific electricity labels or programs.

This guidance also does not list all contractual instruments, energy attribute certificates, or tracking systems used to date.

Endnotes

1. IPCC (2014), based on global emissions from 2010.
2. See the *Corporate Standard* (WRI/WBCSD 2004), pp. 27–28, 42, and 61.
3. See *Corporate Standard* (WRI/WBCSD 2004), Chapter 8.
4. Some research (Gillenwater et al. 2014) has indicated that the voluntary REC market in the U.S., when evaluated based on the price of RECs as an incentive for project developers, has not itself driven new renewable energy projects.

Table 1.2 Which parts of the Guidance should I read?

Question	Reference
What are the changes this guidance introduces from the *Corporate Standard*?	Ch. 1
What terms should I be familiar with to navigate this document?	Ch. 1, 4, 7, 10 and Glossary
What are the business goals for accounting for scope 2 in a corporate GHG inventory?	Ch. 2
What principles should guide my approach to accounting and reporting scope 2 emissions?	Ch. 3
What is the location-based method?	Ch. 4
What is the market-based method?	Ch. 4
What is the decision-making value of the results from each method?	Ch. 4
How do I determine what energy uses should be included in the scope 2 boundary?	Ch. 5
What are the calculation methods I should use for scope 2?	Ch. 6
What kinds of emission factor data can I use for calculating scope 2 according to both methods?	Ch. 6
How do I perform calculations according to both methods?	Ch. 6
What are the criteria that instruments shall meet to be used as emission factors in the market-based method?	Ch. 7
What are the reporting requirements of this guidance?	Ch. 7
What else should I disclose about my purchases?	Ch. 8
How do I show changes over time under both methods?	Ch. 9
How do I set or track goals under one or both methods?	Ch. 9
What is the background on the use of contractual instruments in tracking energy attributes?	Ch. 10
What is the relationship between voluntary purchases and instruments used for mandatory compliance?	Ch. 10 and 11
What is the relationship between offsets and energy attribute instruments?	Ch. 10
How does my contractual purchasing drive change in low-carbon energy supply over time?	Ch. 11
How does this guidance apply to accounting and reporting emissions from purchased heat, steam, and cooling?	Appendix A
How does this new scope 2 accounting and reporting requirement affect accounting for energy-related emissions in scope 3?	Appendix B

2 Business Goals

Before accounting for scope 2 emissions, companies should consider which business goal or goals they intend to achieve.

2.1 Business goals of scope 2 accounting and reporting

Before accounting for scope 2 emissions, companies should consider which business goal or goals they intend to achieve. Consistent with the *Corporate Standard* and *Scope 3 Standard*, companies consuming electricity may seek to:

- Identify and understand the risks and opportunities associated with emissions from purchased and consumed electricity
- Identify internal GHG reduction opportunities, set reduction targets, and track performance
- Engage energy suppliers and partners in GHG management
- Enhance stakeholder information and corporate reputation through transparent public reporting.

Each of these is elaborated below.

2.2 Identify and understand risks and opportunities associated with emissions from purchased and consumed electricity

Electricity is a vital input and resource for most corporate operations, but increasingly poses GHG-related risks. These liabilities arise from climate regulations targeting the energy sector, changing energy technology and fuel costs, tradeoffs between low-carbon sector goals and other environmental objectives (such as country-level policies banning nuclear), and changing consumer preferences for low-carbon products, as well as scrutiny from investors and shareholders over what energy choices a company makes and how it purchases energy. Scope 2 GHG reporting also can introduce reputational risks from GHG claims that are unsubstantiated or unknown.

The results of each scope 2 calculation method highlight different risks and opportunities associated with electricity purchasing and use. Furthermore, the actual contractual instruments claimed in the market-based method will shield or expose companies to different risks associated with the changing cost of energy and related GHG

emissions. Therefore, both methods can improve overall risk assessment and the ability to identify different opportunities to reduce that risk. Likewise, the results of only one scope 2 method may obscure GHG risks associated with energy use and miss mitigation opportunities. Finally, the disclosure of other key information about a company's energy procurement and usage will provide stakeholders insight and context into these risks (see Chapter 8 for a list of these disclosure items).

Risks

Some of these risks include:

Regulatory. Corporate exposure to regulatory risks in the electricity sector depends on regulatory policy design. For instance, CO_2 taxes on electricity consumption may be levied equally on all consumers regardless of their supplier or product choice; based on CO_2 in a supplier's delivered product; or only to certain consumer classes where exemptions may exist (for example, the UK's Climate Change Levy for nonresidential consumers, where a levy exemption certificate can be used to avoid the levy). In these circumstances, a contractual instrument for specified power may or may not shield companies from these additional costs. Customers of an electric utility generally bear the cost of environmental compliance for the resources owned by their utility, or the energy purchased by the utility, which would be shown in a utility-specific emission factor in the market-based method. Conversely, these costs and risks are not necessarily shared among all consumers equally on the same grid, which would otherwise be suggested by the location-based method.

Energy costs and reliability. Electricity suppliers may pass on to their customers the fluctuating prices of fossil or other fuel. The emissions from this supplier mix may be represented in that supplier's specific emission factor, making the market-based method an aligned representation of emissions and costs. At the same time, certain overall costs related to grid operation and maintenance could be allocated to all consumers regardless of their individual choice in electricity supplier, electricity product, or tariff. In addition, maintaining regional grid reliability often requires a mix of generation resources. The location-based method incorporates the GHG emissions of this mix into the grid average emissions factor, while the market-based method may allow users to only evaluate the GHG emissions associated with the energy generation represented in their purchased product—thereby missing some of the reliability risks faced by consumers in the entire grid.

Most companies reduce energy cost risks in part by reducing overall energy consumption. Some companies may be concerned that purchasing certificates annually allows for a "zero emissions" market-based total year-on-year, thereby lessening the impetus for companies to reduce their energy consumption. To mitigate this, the guidance recommends the separate reporting of overall energy consumption. Companies should also compare any additional costs associated with premiums for low-carbon energy supply documented in the market-based method, and compare how those can be reduced over time through decreased demand. In addition, purchasing and applying certificates to one year's inventory sets a precedent for continuing purchases in future years in order to report annual reductions, and cost ranges for certificates may vary each year.

Reputation. Prior to this guidance, companies may have reported scope 2 without fulfilling the Scope 2 Quality Criteria for the market-based method, leading to misleading claims and potential double counting between scope 2 inventories. Transparent disclosure about a company's energy procurement and its key attributes in the market-based method can help clarify the company's strategy and rationale.

Product and Technology. Companies may face decreased consumer demand for products made with high-GHG energy inputs. In turn, a company's competitors using low-GHG energy may see more competitive gains. Being able to compare companies' performances across similar scope 2 methods can help ensure that consumers understand the differences in a company's energy procurement choices.

Legal. Prior to this guidance, some companies with access to contractual information may have been only reporting location-based scope 2. However, many contractual instruments convey legally enforceable rights and claims that can affect how a company describes its purchases and its overall environmental performance. Neglecting to report a market-based scope 2 that aligns with those claims can expose companies to legal risks. In addition, if companies claim in scope 2 the use of instruments that do not meet the Scope 2 Quality Criteria (for example, not conveying an exclusive right to convey attribute claims), they may be inadvertently double-claiming emissions conveyed by other instruments to other parties.

Non-GHG environmental risks

Other environmental risks may be more localized than global GHG emissions affecting the world's climate. A company located in a grid with these types of energy production may also face operational or health/safety risks. A location-based result can help highlight a company's exposure to some of these geographic risks, including (a) air pollution such as sulfur dioxide (SO_x) or mercury from coal combustion; (b) the impact of hydropower on local waterways and aquatic life; and (c) the risks from nuclear waste disposal or emergencies.

Opportunities

Accounting and reporting scope 2 emissions will also highlight opportunities to improve performance and business operations. For many companies, energy use represents a significant cost. Reducing energy use is the "first" choice to reduce impact and costs. In most mixed-resource grids, reducing energy use also correlates with a decreased total in the location-based result (for example, smaller activity data value in the inventory year, while also contributing to lowering grid emissions over time).[1] Companies reducing energy consumption also pay proportionally less for any low-carbon supplier tariffs or premiums, or any unbundled certificates in the market-based method. Some examples of these opportunities are enumerated in Table 2.1.

Table 2.1 Examples of GHG-related opportunities related to scope 2 emissions

Example	Description
Efficiency and cost savings	A reduction in GHG emissions often corresponds to decreased costs and an increase in companies' operational efficiency.
Drive innovation	A comprehensive approach to GHG management provides new incentives for innovation in energy management and procurement.
Increase sales and customer loyalty	Low-emissions goods and services are increasingly more valuable to consumers, and demand will continue to grow for products made with low-carbon electricity.
Improve stakeholder relations	Improve stakeholder relationships through proactive disclosure and demonstration of environmental stewardship. Examples include demonstrating fiduciary responsibility to shareholders, informing regulators, building trust in the community, improving relationships with customers and suppliers, and increasing employee morale. *However, there may also be risks depending on whether company stakeholders are also invested in fossil fuel or high-GHG emitting resources.*
Company differentiation	External parties—including customers, investors, regulators, shareholders, and others—are increasingly interested in documented emissions reductions. Accounting and reporting scope 2 emissions with greater consistency and transparency about contractual instruments demonstrates a best practice that can differentiate companies in an increasingly environmentally conscious marketplace.

2.3 Identify GHG reduction opportunities, set reduction targets, and track performance

Comprehensive scope 2 accounting and reporting should serve as a consistent basis to set reduction targets and measure and track progress toward them over time. Companies should use the boundaries and definitions in scope 2 as a basis for setting GHG reduction targets as well as energy-use targets and renewable energy procurement targets (for example, a 100 percent renewable energy procurement goal). Each method's scope 2 total can provide an important indicator of performance and show the context in which emission totals are changing. For example, regional emission trends (shown in the location-based method) may change over time due to factors outside of a company's direct control, such as electricity supplier quotas for renewable energy, emission policies and regulations, the collective impact of energy efficiency or demand-side management, or voluntary demand for new renewables.

Transparent reporting also allows for a more consistent comparison of performance over time and comparison with other companies. This guidance's framework addresses and reduces double counting between scope 2 inventories when using the same method, improving the accuracy of reported results and ensuring every company can make progress toward its goals.

2.4 Engage energy suppliers and partners in GHG management

Reducing emissions from the energy sector requires the participation of all entities in the energy value chain, including energy generators, suppliers, retailers, and consumers. The two methods outlined in this guidance can help consumers engage with their energy value chain on key demand and supply issues. For instance, generators produce energy in response to local or regional aggregate demand, and individual scope 2 inventories (and recommended reporting of energy consumption separately) can help highlight how reductions in energy use can reduce both scope 2 emissions and contribute to reducing grid-wide demand.

On the supply side, new energy generation facilities require a combination of factors to be in place to come online, including siting appropriate for the technology and its capacity or size, financing, and a supplier or consumer to purchase the energy. Scope 2 accounting can provide a motivation for consumers to partner with suppliers offering low-carbon products, and to seek out opportunities to leverage a company's own financial resources to help develop new projects. Energy producers, suppliers, and consumers all account for GHG emissions based on organizational and operational boundaries (e.g. the scopes). Scope 2 accounting and reporting can help energy consumers identify the GHG emissions impact of different energy production and purchasing arrangements.

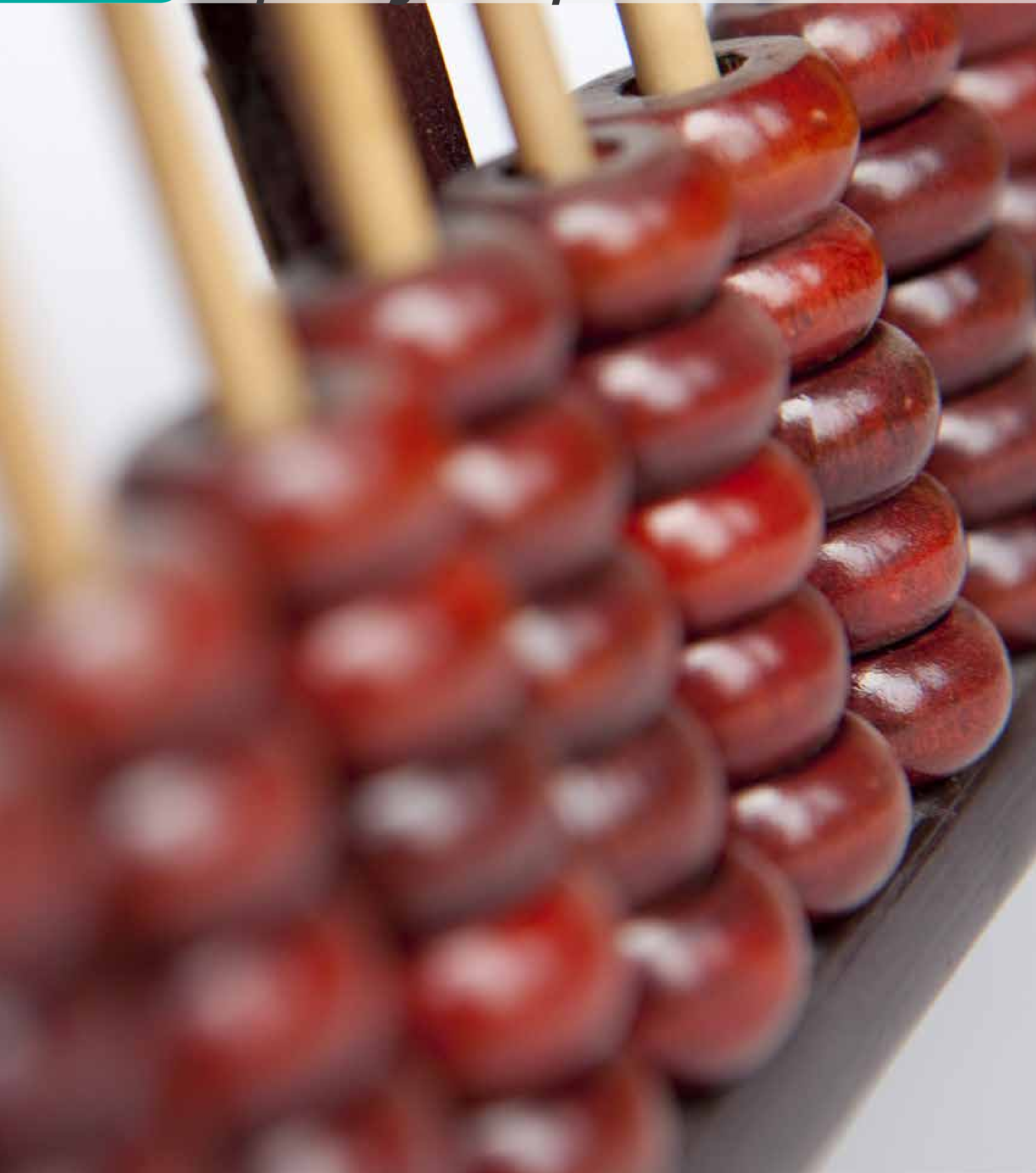
2.5 Enhance stakeholder information and corporate reputation through transparent public reporting

The markets for energy purchasing—as well as markets for energy attribute certificates—may be difficult to explain to stakeholders unfamiliar with attribute tracking, labeling, or claims systems. Reporting scope 2 according to both calculation methods can help describe the different dimensions of the grid more clearly. With the location-based method, consumers can represent that they are served by all the energy resources deployed on their regional grid. By contrast, a company's energy supply choices are shown in the market-based method total. This reflects the market for energy attribute claims which enables a choice of specific resources, and allocates emission attributes based on a company's contractual relationships, or what a company is paying for. Reporting both methods' results provides important information for assessing corporate performance.

Endnotes

1. For this reduction in a single company's consumption to impact grid generation and resulting emissions, this consumption would need to be significant and could not be offset by increases in energy consumption elsewhere in the grid. Therefore this guidance generally treats scope 2 reductions in energy consumption as part of the *collective* action that reduces emissions.

3 Accounting and Reporting Principles



As with financial accounting and reporting, generally accepted GHG accounting and reporting principles are intended to underpin and guide GHG accounting and reporting to ensure that the reported information represents a faithful, true, and fair account of a company's GHG emissions.

GHG accounting and reporting **shall** be based on the following principles:

- **Relevance.** Ensure the GHG inventory appropriately reflects the GHG emissions of the company and serves the decision-making needs of users—both internal and external to the company.
- **Completeness.** Account for and report on all GHG emission sources and activities within the inventory boundary. Disclose and justify any specific exclusion.
- **Consistency.** Use consistent methodologies to allow for meaningful performance tracking of emissions over time. Transparently document any changes to the data, inventory boundary, methods, or any other relevant factors in the time series.
- **Transparency.** Address all relevant issues in a factual and coherent manner, based on a clear audit trail. Disclose any relevant assumptions and make appropriate references to the accounting and calculation methodologies and data sources used.
- **Accuracy.** Ensure that the quantification of GHG emissions is systematically neither over nor under actual emissions, as far as can be judged, and that uncertainties are reduced as far as practicable. Achieve sufficient accuracy to enable users to make decisions with reasonable confidence as to the integrity of the reported information.

Guidance for applying the accounting and reporting principles

These five principles guide the implementation of the GHG Protocol *Scope 2 Guidance*, particularly when application of the guidance in specific situations proves ambiguous. Companies may encounter tradeoffs between principles when completing an inventory and should strike a balance between these principles based on their individual business goals. For instance, a company may find that achieving the most *complete* inventory requires the use of less accurate data, compromising overall accuracy. Over time, as the accuracy and completeness of data increase, the tradeoff between these accounting principles will likely diminish.

Companies should consider these requirements in the light of the overall principles to which they apply, such as:

- **Transparency.** A company may prepare a market-based scope 2 total and may not yet have access to a residual mix emission factor. If the company has contractual instruments such as energy attribute certificates or supplier-specific emission factors to cover all of its consumption, the absence of a residual mix may not impact the accuracy of the company's reported scope 2 total. But it can impact the overall accuracy of the emissions allocation within that market. Therefore, companies are required to disclose this absence transparently.
- **Relevance.** The guidance recommends that companies disclose key features of the contractual instruments they use, in order to enable a clear understanding of the market context of those purchases and a meaningful assessment of the company's procurement strategy (see Chapter 8). While this disclosure should support the principle of transparency, it should also focus on those purchases and features that are most relevant to the company and its goals, and can support its decision making.
- **Consistency.** The guidance seeks to ensure consistency in GHG reporting by requiring dual reporting, so that users of GHG information can track and compare GHG emissions information over time according to the same method assumptions. This better distinguishes trends and changes in performance. A company that begins reporting market-based method results for the first time may wish to provide additional transparent context for this total by indicating what percentage of their operations actually fall under this approach (based on energy usage) as compared with those where the same location-based method is used as a proxy.

- **Accuracy and Completeness.** Companies may identify contractual instruments in the market-based method—such as supplier-specific emission factors or energy purchase contracts—that do not meet the Scope 2 Quality Criteria. To maintain accuracy, companies **shall not** use these data to report a market-based scope 2 total, but should use other eligible data listed in the market-based method hierarchy. Companies may disclose the information separately. Working with electricity suppliers to clarify and ensure alignment of their data with the Scope 2 Quality Criteria will ensure both accuracy and a more complete market-based method result over time.

- **True and Fair.** Some policy makers or stakeholders using corporate GHG information may identify additional objectives for market-based electricity accounting in their national or subnational market. These objectives may reference concepts of social fairness or or equal treatment of different electricity consumer groups in the design of a voluntary low-carbon energy purchasing program. The GHG Protocol references that these five principles should help in developing fair and true inventories. The phrase "fair and true" is not intended to address these types of policies or objectives, but recommends that companies disclose key energy generation features about their contractual instruments in order to transparently disclose how its purchases reflect this policy context.

4 Scope 2 Accounting Methods

This chapter provides an overview of the two scope 2 accounting methods required by this guidance. It outlines how these methods' results can inform decisions that contribute to reductions in the electricity sector.

4.1 Approaches to accounting scope 2

Calculating scope 2 emissions requires a method of determining the emissions associated with electricity consumption. Primarily two methods have been used by companies, programs, and policy makers to "allocate" the GHG emissions created by electricity generation to the end consumers of a given grid. Consumer GHG accounting in scope 2 completes this allocation process through emission factors applied to each unit of energy consumption. This guidance terms these methods the (a) location-based and (b) market-based methods. In short, the market-based method reflects emissions from electricity that companies have purposefully chosen (or their lack of choice), while the location-based method reflects the average emissions intensity of grids on which energy consumption occurs.

Table 4.1 compares the methods in terms of their objectives and the aspects of corporate purchasing and consuming of electricity that are emphasized. Chapter 6 lists the emission factors associated with each method.

4.1.1 Location-based method

This method can apply in all locations since the physics of energy production and distribution functions the same way in almost all grids, with electricity demand causing the need for energy generation and distribution. It emphasizes the connection between collective consumer demand for electricity and the emissions resulting from local electricity production. This includes an overall picture of the mix of resources required to maintain grid stability (see Box 4.1). The location-based method is based on statistical emissions information and electricity output aggregated and averaged within a defined geographic boundary and during a defined time period.[1]

Grid average emission factors should be distinguished from supplier-specific emission factors. While utilities may be the sole energy provider in a region and produce a supplier-specific emission factor that closely resembles the overall regional grid average emissions factor, this utility-specific information should still be categorized as market-based method data due to the wide variation in utility service areas and structures. For instance, the utility service territory may

Table 4.1 Comparing market-based and location-based methods

	Market-Based Method	Location-Based Method
Definition	A method to quantify the scope 2 GHG emissions of a reporter based on GHG emissions emitted by the generators from which the reporter contractually purchases electricity bundled with contractual instruments, or contractual instruments on their own	A method to quantify scope 2 GHG emissions based on average energy generation emission factors for defined geographic locations, including local, subnational, or national boundaries
How method allocates emissions:	Emission factors derived from the GHG emission rate represented in the contractual instruments that meet Scope 2 Quality Criteria	Emission factors representing average emissions from energy generation occurring within a defined geographic area and a defined time period
Where method applies:	To any operations in markets providing consumer choice of differentiated electricity products or supplier-specific data, in the form of contractual instruments	To all electricity grids
Most useful for showing:	• Individual corporate procurement actions • Opportunities to influence electricity suppliers and supply • Risks/opportunities conveyed by contractual relationships, including sometimes legally enforceable claims rules	• GHG intensity of grids where operations occur, regardless of market type • The aggregate GHG performance of energy-intensive sectors (for example, comparing electric train transportation with gasoline or diesel vehicle transit) • Risks/opportunities aligned with local grid resources and emissions
What the method's results omit:	• Average emissions in the location where electricity use occurs	• Emissions from differentiated electricity purchases or supplier offerings, or other contracts

be a smaller region than the grid distribution area serving a given site of consumption; conversely, many utilities are in competitive markets where multiple suppliers can compete to serve consumers in the same region. Therefore, this method only looks at the broader energy generation profile for a region, regardless of supplier relationships.

4.1.2 Market-based method

The market-based method reflects the GHG emissions associated with the choices a consumer makes regarding its electricity supplier or product. These choices—such as choosing a retail electricity supplier, a specific generator, a differentiated electricity product, or purchasing unbundled energy attribute certificates—are conveyed through agreements between the purchaser and the provider.

Under the market-based method of scope 2 accounting, an energy consumer uses the GHG emission factor associated with the qualifying contractual instruments it owns. In contrast to the location-based method, this allocation pathway represents contractual information and claims flow, which may be different from underlying energy flows in the grid. The certificate does not necessarily represent the emissions caused by the purchaser's consumption of electricity. One company choosing to switch suppliers does not directly or in the short-term impact the entire operation of the grid and its emissions. Over time, the

Box 4.1 How scope 2 methods reflect variable energy

While renewable energy may be "zero emissions" at the point of generation, dispatchable fossil fuel resources are often required to maintain overall grid reliability when renewable resources like solar and wind are not available. Electricity system operators may be required to maintain "spinning reserves" to provide grid stability in the event of losses of production at major energy generation facilities or to regulate grid frequency. Most studies suggest that a balancing area can absorb up to 30 percent variable resources without special accommodation. Over time increases in variable renewable resources have led to the formation of larger balancing areas supported by expanded T&D infrastructure as well as increased grid flexibility and efficiency improvements. Improved short-term forecasting of variable resources and storage technologies will also minimize these challenges.

The location-based method reflects the role of these "balancing" resources and their emissions through grid average emission factors. These emission factors include emissions from all local energy generation. The market-based method may reflect these emissions in varying degrees: for instance a certificate for variable renewable energy will not likely report or show the GHG impacts of the other resources dispatched on the grid to complement that variability. However some utilities are designing certificates to be issued only from variable energy generated during periods when the "backup" resource is also zero emissions or when no back-up is needed. This requires the utility to be in a position to guarantee they inject at any moment enough zero emissions energy to cover demand (for instance, through hydropower). For example, TUV SUD certifies in their EE02 Standard that energy is supplied simultaneously to consumption.*

*See TUV SUD criteria: http://www.tuev-sued.de/plants-buildings-technical-facilities/fields-of-engineering/environmental-engineering/energy-certification/certification-criteria

collective consumer demand for particular energy types and their resulting attributes (e.g., zero GHG emissions from generation) can send a market signal to support building more of those types of generation facilities, just as purchasing any product sends the market signals to produce more of that product.

While only a few countries around the world have established markets for certificates that support this method, large electricity consumers in many other markets may find opportunities to purchase a differentiated product or enter into contracts directly. The market-based method has historically been associated with green power purchasing options. However, it is designed to integrate with, and include, existing systems for supplier portfolio disclosure and nonrenewable energy contract types as well. Since no market has instituted comprehensive energy tracking by contractual instruments,[2] this method uses some of the same energy production and emissions data from the location-based method for any energy not tracked by an instrument. The emissions from all untracked and unclaimed energy comprise a residual mix emission factor. Consumers who do not make specified purchases or who do not have access to supplier data should use the residual mix emission factor to calculate their market-based total.

With this method, individual energy consumers have the opportunity to make decisions about their product and supplier, which can then be reflected as a supplier or product-specific emission factor in scope 2.

4.2 Emission rate approach

These scope 2 accounting methods have several features in common, including:

- They use generation-only emission factors (e.g. emissions assessed at the point of energy generation), designed to label emissions associated with a quantity of electricity delivered and consumed. The emission factors do not include T&D losses or upstream life-cycle emissions associated with the technology or fuel used in generation. Instead, these other categories of upstream emissions should be quantified and reported in scope 3, category 3 (emissions from fuel- and energy-related activities not included in scope 1 or scope 2). In the case of supplier-specific emission factors, the emission factor should reflect emissions from all delivered energy, not just from generation facilities owned/operated by the utility.

- They represent emission rates that allocate emissions at generation to end-users. This type of treatment is consistent with corporate inventory approaches across other scopes, particularly with product-specific emission factors or labels. Both methods should be applied comprehensively to ensure all energy generation emissions within a defined region have been accounted for.
- This guidance does not support an "avoided emissions" approach for scope 2 accounting due to several important distinctions between corporate accounting and project-level accounting. However, companies can report avoided grid emissions from energy generation projects separately from the scopes using a project-level accounting methodology.

4.3 The decision-making value of each method's results

The *Corporate Standard* notes that reductions in indirect emissions (changes in scope 2 or 3 emissions over time) may not always capture the actual emissions reduction accurately. This is because there is not always a direct cause-effect relationship between the single activity of the reporting company (purchasing and consuming energy) and the resulting GHG emissions on the grid.[3] Generally, as long as the accounting of indirect emissions over time recognizes activities that in aggregate change global emissions, any such concerns over accuracy should not inhibit companies from reporting their indirect emissions.[4]

These two scope 2 accounting methods each provide a different "decision-making value" profile—that is, different indications of performance and risks, revealing different levers to reduce emissions and reduce risks. Ultimately, system-wide emission decreases are necessary over time to stay within safe climate levels. Achieving this requires clarity on what kinds of decisions individual consumers can make to reduce both their own reported emissions as well as contribute to emission reductions in the grid. Working backward from those decisions to the methods used to calculate emissions, there are three types of decisions companies can make that impact overall electricity grid emissions. These decisions include facility siting, the level and timing of demand, and supporting supply shifting.

While companies may make decisions related to these categories for non-GHG considerations, all the decisions carry GHG implications.

1. **Facility and operations-siting decisions**
   A company's decisions about where to locate its office buildings, industrial facilities, distribution centers, or data centers carries GHG implications. The physical location of these points of energy consumption impacts what existing, or future, energy resources may be able to be deployed to meet demand. For instance, locating new facilities on a GHG-intensive grid means that in the near term, energy demand will be met with a higher GHG emissions profile, assuming that the energy is consumed locally. By contrast, locating operations in areas with low-carbon natural resources, or additional benefits such as natural ambient cooling or heat, can reduce these GHG emissions risks (as shown in the location-based method).[5] Ambient heat/cooling will also be reflected in lower use of heat/cooling and will be seen in both the location-based and market-based methods. Companies considering electric transportation fleets also need to ensure the availability of charging infrastructure and the GHG-intensity of the grids where that transportation would occur.

   The physical location also aligns with a national or subnational set of regulatory rules governing what types of energy product or energy supplier choices a consumer can make. This location highlights different pathways and options for corporate influence over the energy supply mix over time (as shown in the market-based method).

   Therefore, a company's shift in facility location will result in changes in scope 2 based on:

   - **Location-based.** The use of a different grid average emission factor, and possibly a shift in energy supply overall, if the new location allows for on-site energy generation or is locating near an energy development where a direct line connection can be made.
   - **Market-based.** Changes in supplier (new utility service area), changes in other types of contractual instruments, actions of other consumers in the market, or the residual mix used in that location.

2. **Decisions on the level and timing of demand**
   Once a company has established a location for its operations, it can reduce its emissions through energy demand reduction.[6] A company can reduce energy consumption through measures such as choosing an energy-efficient building, carrying out energy-efficient retrofits, using more efficient electronics or lighting, and making behavioral decisions. Increasingly, "smart grid"[7] information and systems are allowing more geographically and temporally precise data to support energy demand management at a consumer level, including end-use equipment timing (e.g., running dishwashers or washing machines during optimal times of day such as low-cost, or non-peak times). Utilities may also provide this type of data to energy-intensive consumers as part of demand-side management (DSM) programs and peak-shaving efforts. The location-based method assumes that local demand impacts local generation and distribution patterns, which ultimately impact total GHG emissions from the system (taking into account physical energy imports/exports). While demand is met with incremental resources, grid-average emission factors provide more readily available averages calculated over the course of a year.

   Therefore, a company's shift in energy demand quantity and timing will entail changes in reported scope 2 primarily through activity data. In both methods, a decrease in electricity consumption can decrease total reported scope 2.

   - **Location-based.** Collective changes in consumption contribute to changes in the the grid average emission factor over time. Shifting energy consumption to periods with of low-emissions generation on the grid (often non-peak hours) can further contribute to system-wide reductions. Advanced grid studies

can better highlight the emissions impacts of these individual consumption decisions (see Chapter 6).

- **Market-based.** Reducing electricity demand can minimize the additional costs associated with purchasing contractual instruments at a premium above standard electricity costs. However, the market-based method runs the risk of providing less visibility on energy demand reduction if the price of this premium (and therefore the price of achieving "zero emissions") is low. But efficiency can generally be pursued with financial gain regardless of the specific emissions associated with electricity consumption.

3. Decisions to influence grid mix of generation technologies

Many variables impact the mix of generation technologies on a given grid, including the historical regulatory, financial, and physical characteristics of the jurisdiction as well as the current market dynamics of supply/demand for particular resources. An electricity consumer can pursue a variety of actions to try to influence these factors directly or indirectly, conveying stronger or weaker market signals (see Chapter 11). If consumers want to support low-carbon technologies, they can:

- Create on-site low-carbon energy projects
- Establish contracts, that include certificates, such as PPAs directly with low-carbon generators
- Negotiate with their supplier or utility to supply low-carbon energy to the company
- Switch to a low-carbon electricity supplier or electricity product, where available
- Purchase certificates from low-carbon energy generation.

Substantially changing a grid's resource mix over time generally requires aggregate consumer decisions, or a large-scale corporate consumer representing a significant percentage of a utility's load. But all of these interventions benefit from, and depend on, a contractual instrument (e.g. certificate) that confers specific GHG-emission attribute claims associated with purchases, functioning as a demand-signaling mechanism.

Therefore, efforts to shift grid supply through procurement will entail changes in reported scope 2 based on:

- **Location-based.** Cumulative effect of consumer or supplier choices over time that change the grid average emissions factor. (Other factors such as economics and environmental regulation can also impact this.) But individual corporate choices regarding electricity contracts, supplier choices, or certificate purchases are *not* directly reflected in an individual's scope 2 inventories using the location-based method.
- **Market-based.** Individual corporate choices of electricity product or supplier, or the lack of a differentiated choice, which requires the use of a residual mix. Many market-based tracking systems currently only reflect renewable generation contractual instruments, but the method should reflect any type of contract or supplier-specific emission factor that meets the Scope 2 Quality Criteria. Chapter 11 addresses how companies can use the market-based method to drive supply change.

Endnotes

1. The International Energy Agency provides grid average data per country and per year. In some countries grid average data are available for much shorter periods. RTE in France provides grid average figures in real time for every 30 minutes period (http://www.rte-france.com/en/eco2mix/eco2mix-co2-en).
2. Only the NEPOOL and PJM regions of the U.S. use all generation certificate tracking.
3. It is assumed here that direct emissions tracked in scope 1 do reflect absolute reductions. However, it should be noted that a company may see its scope 1 emissions change due to outsourcing or acquisition/divestment, activities which do not in themselves "change" global GHG emissions but which simply change what company has responsibility for them.
4. *Corporate Standard* (WRI/WBCSD 2004), p. 59–60.
5. However, emissions associated with the relocation of a facility (building materials, demolition, trucking, etc.) unrelated to the new or old site's purchase of electricity or steam would generally be accounted for in scope 3
6. This is not as relevant for a totally new facility whose energy use would still reflect an increase on the grid. However, efficiency and demand reduction can remain a priority for consumption occurring in established buildings.
7. See EPRI (2008).

5 Identifying Scope 2 Emissions and Setting the Scope 2 Boundary

This chapter describes the sources of scope 2 emissions and how to establish a boundary for scope 2 accounting under different generation and distribution models and scenarios.

5.1 Organizational boundaries

As detailed in the *Corporate Standard,* a company can choose one of three consolidation approaches for defining its organizational boundaries for the entire corporate inventory, including equity share, financial control, and operational control. Companies should use a consistent consolidation approach over time for their entire inventory.

5.2 Operational boundaries

After a consolidation approach has been determined to define the organizational boundary, it **shall** be applied consistently across the inventory. Companies can then identify emissions from included sources and categorize them into direct and indirect emissions, and further by "scopes." The *Corporate Standard* divides a company's emissions into direct and indirect emissions:

- **Direct emissions** are emissions from sources that are owned and controlled by the reporting company. These emissions are considered scope 1.
- **Indirect emissions** are emissions that are a consequence of the activities of the reporting company, but occur at sources owned or controlled by another company. These include scope 2 and scope 3 emissions. Scope 2 includes emissions from energy purchased or acquired and consumed by the reporting company (see Section 5.3 for expanded definition). Scope 3 emissions include upstream and downstream value chain emissions and are an optional reporting category in the *Corporate Standard.* The *Corporate Value Chain (Scope 3) Accounting and Reporting Standard* (2011) outlines how to conduct a comprehensive scope 3 inventory.

For many companies, scope 2 and scope 3 represent the largest sources of GHG emissions. By allowing for GHG accounting of direct and indirect emissions by multiple companies in a supply chain, multiple entities can work to reduce emissions where they have influence.

The underlying framework of direct and indirect corporate emissions reporting means that one company's scope 1 is another company's scope 2 and/or 3. This is an inherent part of the reporting framework that enables multiple entities along a value chain to consistently report those

emissions. However, as stated in the *Corporate Standard,* companies should avoid double counting the same emissions in multiple scopes in the same inventory. In addition, double counting the same emissions within the same scope by multiple companies should also be avoided (see Section 5.5).

5.2.1 Leased assets

Energy use in leased buildings or from leased electricity generation assets can be a significant emissions source. To determine whether the assets' emissions are included in the inventory boundary and how they should be categorized by scope, companies should determine the entity that owns, operates, or exerts control over certain leased assets.[1]

As noted in the *Corporate Standard* and its supplemental Appendix F (available at ghgprotocol.org), all leases confer operational control to the lessee or tenants, unless otherwise noted.[2] Therefore, if a company is a tenant in a leased space or using a leased asset and applies the operational control approach, any energy purchased or acquired from another entity (or the grid) **shall** be reported in scope 2. On-site heat generation equipment, such as a basement boiler, typically falls under the operational control of the landlord or building management company. Tenants therefore would report consumption of heat generated on-site as scope 2. If a tenant can demonstrate that they do not exercise operational control in their lease, they **shall** document and justify the exclusion of these emissions.

Emissions from assets a company owns and leases to another entity, but does not operate, can either be included in scope 3 or excluded from the inventory. For more information on organizational boundaries, see The *Corporate Standard,* Chapter 3: Setting Organizational Boundaries, and Appendix F at www.ghgprotocol.org.

5.3 Defining scope 2

Scope 2 is an indirect emission category that includes GHG emissions from the generation of purchased or acquired electricity, steam, heat, or cooling consumed by the reporting company.[3] GHG emissions from energy generation occur at discrete sources owned and operated by generators that account for direct emissions from generation in their scope 1 inventory. Scope 2 includes indirect emissions from generation only; other upstream emissions associated with the production and processing of upstream fuels, or transmission or distribution of energy within a grid, are tracked in scope 3, category 3 (fuel- and energy-related emissions not included in scope 1 or scope 2).

5.3.1 Forms of energy use tracked in scope 2

Scope 2 accounts for emissions from the generation of energy that is purchased or otherwise brought into the organizational boundary of the company. At least four types of purchased energy are tracked in scope 2, including the following:

Electricity. This type of energy is used by almost all companies. It is used to operate machines, lighting, electric vehicle charging, and certain types of heat and cooling systems.

Steam. Formed when water boils, steam is a valuable energy source for industrial processes. It is used for mechanical work, heat, or directly as a process medium.

Combined heat and power (CHP) facilities (also called cogeneration or trigeneration) may produce multiple energy outputs from a single combustion process. Reporting companies purchasing either electricity or heat/steam from a CHP plant should check with the CHP supplier to ensure that the allocation of emissions across energy outputs follows best practices, such as the *GHG Protocol Allocation of GHG Emissions from a Combined Heat and Power (CHP) Plant (2006).*

Heat. Most commercial or industrial buildings require heat to control interior climates and heat water. Many industrial processes also require heat for specific equipment. That heat may either be produced from electricity or through a non-electrical process such as solar thermal heat or thermal combustion processes (as with a boiler or a thermal power plant) outside the company's operational control.

Cooling. Similar to heat, cooling may be produced from electricity or through the distribution of cooled air or water.

This guidance focuses on electricity accounting. Differences in accounting for heat, cooling, and steam are treated in Appendix A.

5.4 Distinguishing scopes reporting by electricity production/distribution method

Once energy is generated, it is either consumed on-site, or distributed to another entity by direct line transfer or through the electricity grid. These pathways, along with any contractual and/or certificate sales from electricity generation from owned/operated equipment, determine how the emissions from energy generation are accounted for and reported by different entities in scope 1 and 2. (Scope 3 accounting is addressed in Appendix B.) Scope 2 emissions are accounted for when a company obtains its energy from another entity, or when a company sells an energy attribute certificate from owned and consumed generation. See Chapter 10 for background on energy attribute certificates.

Under all four scenarios identified below, companies should report electricity consumption separately from the scopes as part of reporting the total quantity of energy consumption in kWh, MWhs, TJ, BTUs or other relevant units.

1. If the consumed electricity comes from owned/operated equipment (Figure 5.1)

If energy is produced and consumed by the same entity (with no grid connection or exchanges), no scope 2 emissions are reported, as any emissions occurring during the power generation are already reported in scope 1. This scenario may apply to large industrial facilities that generate their own energy on-site in owned/operated equipment.

Figure 5.1 Energy production and consumption from owned/operated generation

2. If the consumed electricity comes from a direct line transfer (Figure 5.2)

In this example, energy production is fed directly and exclusively to a single entity—here, Company B. This applies to several types of direct line transfers, including:

- An industrial park or collection of facilities, where one facility creates electricity, heat, steam, or cooling and transfers it directly to a facility owned or operated by a different party.
- For energy produced by equipment installed on-site (e.g. on-site solar array or a fuel cell using natural gas) that is owned and operated by a third party.
- For electricity, heat, steam, or cooling produced within a multi-tenant leased building (by a central boiler, or on-site solar) and sold to individual tenants who do not own or operate the building or the equipment. Tenants may pay for this energy as part of a lump rental cost and the tenant may not receive a separate bill.

In any of these scenarios:

- The company with operational or financial control of the energy generation facility would report these emissions in their scope 1, following the operational control approach, while the consumer of the energy reports the emissions in scope 2.
- Any third-party financing institution that owns but does not operate the energy generation unit **would not** account for any scope 1, 2, or 3 emissions from energy generation under the operational control approach, since they do not exercise operational control. Only the equipment operator would report these emissions in their scope 1 following an operational control approach. Equipment owners would account for these generation emissions in scope 1 under a financial control or equity share approach, however.
- If all the energy generation is purchased and consumed, then Company B's scope 2 emissions will be the same as Company A's scope 1 emissions (minus any transmission and distribution losses, though in most cases of direct transfer there will be no losses).[4]

3. If the consumed electricity comes from the grid (Figure 5.3)

Most consumers purchase or acquire some or all of their electricity through the electric grid, a shared electricity distribution network. Depending on the design of the grid, there may be a small number of central generation facilities providing energy to many consumers, or there may be a large number of generation facilities representing different technology types (thermal power using coal or natural gas inputs, or wind turbines, solar photovoltaic cells, or solar thermal, etc.).

Figure 5.2 Direct line energy transfer

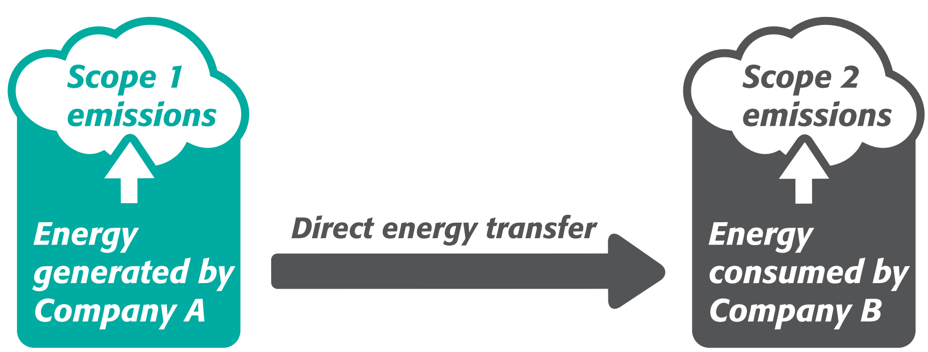
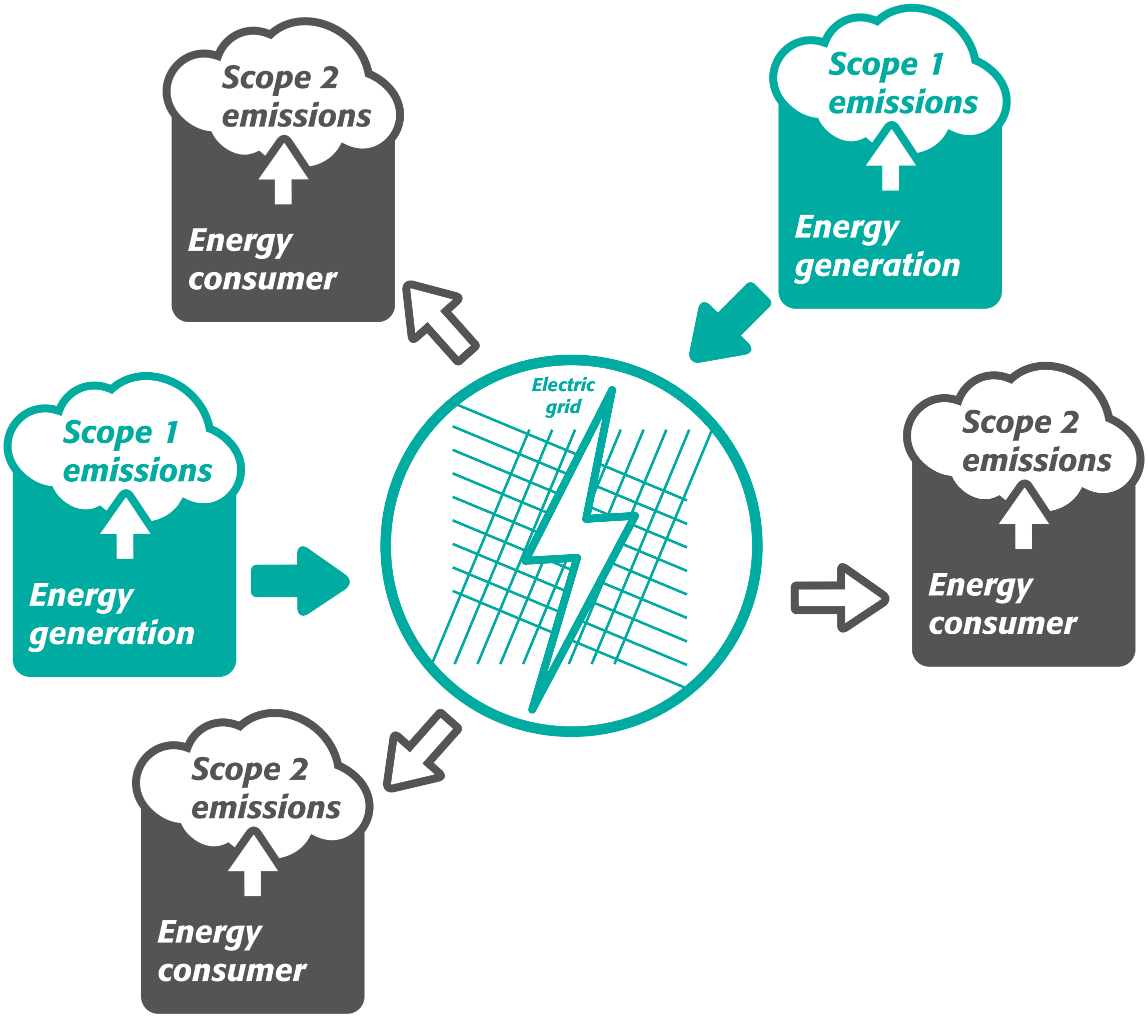


Figure 5.3 Electricity distribution on a grid



Electricity generators report any emissions from generation in scope 1, but most renewable or nuclear technology would report “zero” emissions from this generation. A grid operator or utility dispatches these generation units throughout the day on the basis of contracts, cost, and other factors. Because it is a shared network as opposed to a direct line, consumers may not be able to identify the specific power plant producing the energy they are using at any given time.[5] Use of specified generation on the grid can only be determined contractually. Energy on the grid moves to the nearest point it can be used, and multiple regions can exchange power depending on the capacity and needs of these regions. Steam, heat, and cooling can also be delivered through a grid, often called a district energy system. Such systems provide energy to multiple consumers, though they often have only one generation facility and serve a more limited geographic area than electricity grids.

4. If some consumed electricity comes from owned/operated equipment, and some is purchased from the grid (Figure 5.4).

Some companies own, operate, or host energy generation sources such as solar panels or fuel cells on the premises of their building or in close proximity to where the energy is consumed. This arrangement is often termed “distributed generation” or “on-site” consumption, as it consists of generation units across decentralized locations (often on the site where the energy output will be consumed, as opposed to utility-scale centralized power plants). The company may consume some or all of the energy output from these generation facilities; sell excess energy output back to the grid; and purchase additional grid power to cover any remaining energy demand.

The owners/operator of a distributed generation facility may therefore have both scope 1 emissions from energy generation, as well as scope 2 emissions from any energy purchased from the grid, or consumed from on-site generation where attributes (e.g. certificates) are sold. This arrangement impacts activity data as follows:

Activity data. Determining the underlying activity data (in MWh or kWh) in these systems may be challenging given the flux of electricity coming in or flowing out. Many markets utilize "net metering" for these systems, which allows grid purchases to be measured only as *net* of any energy exported to the grid. This net number may also be the basis for how costs are assessed.

For accurate scope 2 GHG accounting, companies **shall** use the total—or gross—electricity purchases from the grid rather than grid purchases "net" of generation for the scope 2 calculation. A company's total energy consumption would therefore include self-generated energy (any emissions reflected in scope 1) and total electricity purchased from the grid (electricity). It would exclude generation sold back to the grid.

If a company cannot distinguish between its gross and net grid purchases, it should state and justify this in the inventory.

Table 5.1 illustrates the difference between total energy consumption and net energy consumption (if the reporter is a net grid consumer rather than producer). A negative

Figure 5.4 Facility consuming both energy generated on-site and purchased from the grid

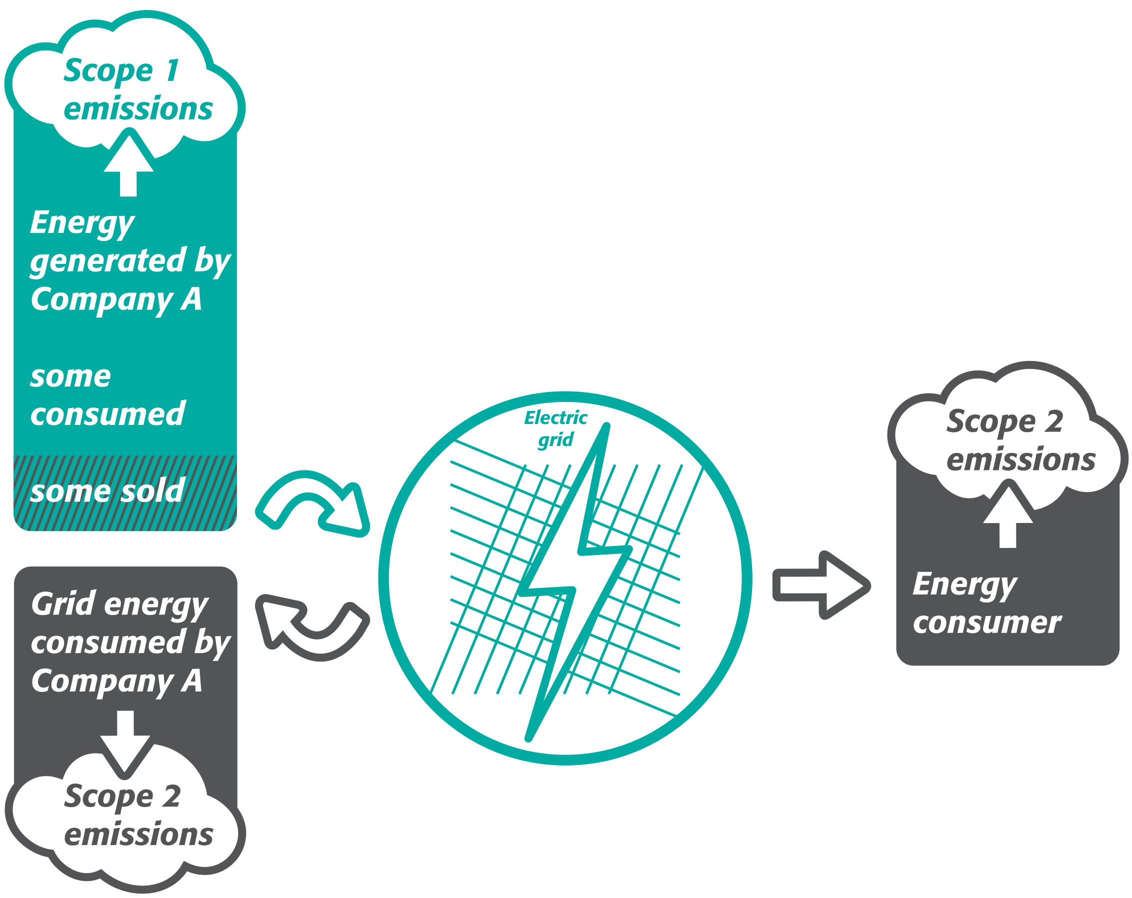


Table 5.1 Comparing gross and net energy consumption

Total energy production from on-site system	On-site energy consumption from on-site system	Energy exported from the on-site system to the grid	Energy imported from the grid
100 kWh	50 kWh	50 kWh	70 kWh
Total energy consumption (to be reported separately) = 120 kWh 50 kWh consumed from on-site system + 70 kWh imported from grid			
"Net" grid consumption= 20 kWh (70 kWh imported from grid - 50 kWh exported)			

consumption number for net energy exporters demonstrates the challenge of using net consumption information as activity data.

Because scope 2 reflects energy purchased from a separate entity outside the inventory boundary, energy consumed from owned/operated facilities may not be reported in scope 2, depending on the sale of attributes.

5.5 Avoiding double counting in scope 2

The dual reporting requirement in this guidance can complicate the understanding of whether double counting is occurring and whether it threatens an inventory's accuracy.

Table 5.2 details several scenarios of double counting, along with whether they introduce accuracy errors and how they are, or can be, addressed.

5.6 Avoiding double counting between owned energy generation assets (scope 1) and grid-delivered energy consumption in separate operations (scope 2)

Some companies such as electricity utilities or suppliers may own energy generation facilities that sell all their power into the local grid. Emissions from these generation facilities are reported in scope 1 of the utility's inventory. At the same time, the utility may have separate administrative, commercial, or industrial facilities or office buildings (apart from the generation facilities)[6] that consume electricity from the same grid to which the utility is supplying—which would be reported in scope 2. Following the *Corporate Standard* scopes framework, companies should avoid reporting the same emissions in scope 1 and 2 of the same company's inventory; but in the case of utilities, a scope 2 calculation according to *either* the location-based or market-based approach would likely include emissions from the generation assets reported in scope 1. This is because

Table 5.2 Additions to scope 2 accounting introduced by the *Scope 2 Guidance*

Type of double counting	Examples	How to prevent double counting
Between scope 1 and 2		
Between scope 1 and 2 in different inventories	A company reports emissions from grid-delivered energy use in scope 2, while a generation facility on the grid reports its facility's emissions in scope 1.	No double counting problem—this is an inherent part of the corporate reporting framework.
Between scope 1 and 2 in the same inventory	A company owns a natural gas fuel cell and consumes the output directly (with no grid transfers).	Depending on the consolidation approach chosen, emissions from owned/operated generation shall be reported under scope 1 (if any emissions occur). The emissions from consumed energy shall not be repeated in scope 2 since they have already been reported in scope 1.
Between multiple companies' scope 2 inventories		
Between multiple companies' scope 2 inventories based on different methods	In aggregate: The energy attribute certificates from a renewable generation facility are sold to a company who claims them and reports their emission rate in scope 2 (market-based). The grid emissions factor for the region will also reflect this facility's emission rate. Consumers using the grid emissions factor (location-based method) will be double counting the emission rate conveyed by the energy attribute certificate (market-based method).	This is an inherent condition of two methods. Each method's results shall not be added or netted. Each method represents a separate way of allocating energy generation emissions, so depending on geographic or market boundaries, each method's scope 2 result can reflect some of the same emissions reflected in the other method.
Between multiple companies' scope 2 inventories of the same method	May occur in the market-based method if energy attribute certificates are sold from an owned/operated solar panel, but owner also consumes the energy and claims zero emissions rate.	If energy attribute certificates are sold from energy generation, companies shall treat consumed electricity as though it were purchased from the grid—using the hierarchies of emission factors indicated for both methods (Table 6.2 and Table 6.3). Sold energy attribute certificates may be reported separately. Scope 1 reporting shall still reflect any emissions from the generator.
	May occur in the location-based method if grid emission factors reflect different geographic boundaries (e.g. local, regional, national). May occur in the market-based method if instrument claims are unclear (see instrument tracking below), or if residual mix is not available	This is a function of data rather than the accounting framework. Companies shall use the most accurate and appropriate emission factors listed in the emission factor hierarchy for each method (see Chapter 6).
	Two different certificate types are generated from a single MWh (one for supplier quotas, one for supplier disclosure). Neither certificate is clear on whether energy attribute claims are included. If users assume they are, different suppliers may count the same attributes in their mix.	This guidance's Scope 2 Quality Criteria require consumers to ensure that only one instrument conveys a GHG emission rate claim to consumers, and that that claim be clearly conveyed with the instrument, or if multiple instruments convey the GHG emission rate claim, that all such instruments be owned and retired to substantiate a usage and scope 2 claim.

the owned generation facilities will be supplying the same grid region where their electricity consumption occurs.

Therefore, to minimize double counting between scope 1 and 2 within the same inventory, companies in this situation should treat their grid consumption as though it were supplied by their own generation facilities (e.g. as though they were an "on-site" source), with no additional emissions reported in scope 2 (see row 2 of Table 6.1 for this scenario). The grid-consuming facility should secure a contract or other instrument with its own generation unit(s) to convey the claim following the Quality Criteria in the market-based method, including ensuring that there have not been any sales from that production conveying claims to other parties. If possible, utilities should also remove from any supplier-specific emission factor or third-party data collectors the quantity of energy (and its emissions) supplied to or associated with these commercial/industrial operations.

Any energy consumption not covered by contractual arrangements with owned/operated generation units should be treated as grid-consumed energy in scope 2, reported according to both the location-based and market-based method emission factor hierarchies.

Endnotes

1. See *Corporate Standard* (WRI/WBCSD 2004), p. 31.
2. In some leased building arrangements, tenants do not pay for electricity individually. However, this should not exempt tenants from reporting the emissions from that energy use. As defined in the next section, scope 2 includes energy that is acquired and consumed.
3. *Corporate Standard* (WRI/WBCSD 2004), p. 25. The word "acquired" was added in the *Scope 3 Standard* (p. 28) to reflect circumstances where a company may not directly purchase electricity (e.g., a tenant in a building), but where the energy is brought into the organization's facility for use.
4. Line losses in Figure 5.2 can be separately reported in Company B's scope 3. If Company A owns the line, it does not need to report these line-loss emissions separately since they have already been reported in scope 1.
5. In rare situations, such as islands with a single, small grid, it may be possible to determine which power station was operating and providing power to the grid users.
6. These administrative buildings should be distinguished from auxiliary operations adjacent to generation facilities. Auxiliary operations may use electricity directly from the generation facility even before distribution and sales to the grid.

6 Calculating Emissions

This chapter outlines key requirements, steps, and procedures involved in calculating scope 2 emissions according to each method.

Once the inventory boundary has been established, companies generally calculate GHG emissions using the following steps:

- Identify GHG emission sources for scope 2 emissions
- Determine whether the market-based approach applies
- Collect activity data and choose emission factors for each method
- Calculate emissions
- Roll up GHG emissions data to corporate level.

Additional guidance on general calculation procedures and GHG Protocol calculation tools can be found in Chapter 6 of the *Corporate Standard.*

6.1 Identify GHG emissions sources for scope 2

Scope 2 includes emissions from all purchased/acquired and consumed electricity, heat, steam, or cooling. Companies can identify these energy uses on the basis of utility bills or metered energy consumption at facilities within the inventory boundary.

6.2 Determine whether the market-based method applies for any operations

Companies can determine whether the market-based method for scope 2 calculation applies to their inventory by assessing whether differentiated energy products in the form of contractual instruments (including direct contracts, certificates, or supplier-specific information) are available in a given market. Markets are increasingly developing and refining purchasing options, and the list is not exhaustive. Currently this includes EU member states and economic area, the U.S., Australia, most Latin American countries, Japan, India, and many others. Figure 6.1 illustrates this determination.

- The presence of contractual information in any market where a company has operations triggers the requirement to report according to the market-based method. The contractual instruments themselves must be assessed for their conformance with Scope 2 Quality Criteria. If they do not meet the Scope 2 Quality Criteria, then other data (listed in Table 6.3) **shall** be used as an alternative in the market-based method total. In this way, all companies required to report according to the market-based method will have some type of data option.

- If a multi-regional company has any operations within the corporate inventory where the market-based method applies, then a market-based method total **shall** be calculated for the entire corporate inventory to ensure completeness and consistency. For any individual operations in the corporate inventory where market-based method data on the hierarchy is not applicable or available, data from the location-based method should be used to represent the emissions from the facility (see Table 6.3). For these operations, the calculated scope 2 according to the market-based method will be identical to the location-based.

If no facilities in the entire organizational boundary of the reporting entity are located in markets with contractual claims systems, or where *no* instruments within those systems meet Scope 2 Quality Criteria required by this document, then only the location-based method **shall** be used to calculate scope 2.

6.3 Collect activity data

For electricity use disclosure required by this guidance, activity data includes all electricity purchased/acquired and consumed during the reporting period, including from owned/operated generation facilities that may not be included as activity data for scope 2 calculation.

For scope 2 calculation, activity data includes all energy purchased/acquired and consumed from an entity outside of the organization or from owned/operated generation facilities where energy attributes (e.g. certificates) have been sold or transferred. Table 6.1 indicates how different energy distribution methods should be treated.

To determine activity data, metered electricity consumption or utility bills specifying consumption in MWh or kWh units can provide the most precise activity data. In some cases these may not be available, as with consumption occurring in a shared space without energy metering. In these cases, estimations may be used such as allocating an entire building's electricity usage to all tenants on the basis of the reporter's square footage and the building's occupancy rate (called the Area Method).[1]

6.4 Identify distribution scenarios and any certificate sales

All of the distribution scenarios identified in Section 5.4 can entail the generation and sale of energy attribute certificates or other contractual instruments. The sale or retention of these instruments impacts the accounting of the consumed energy, as shown in Table 6.1.

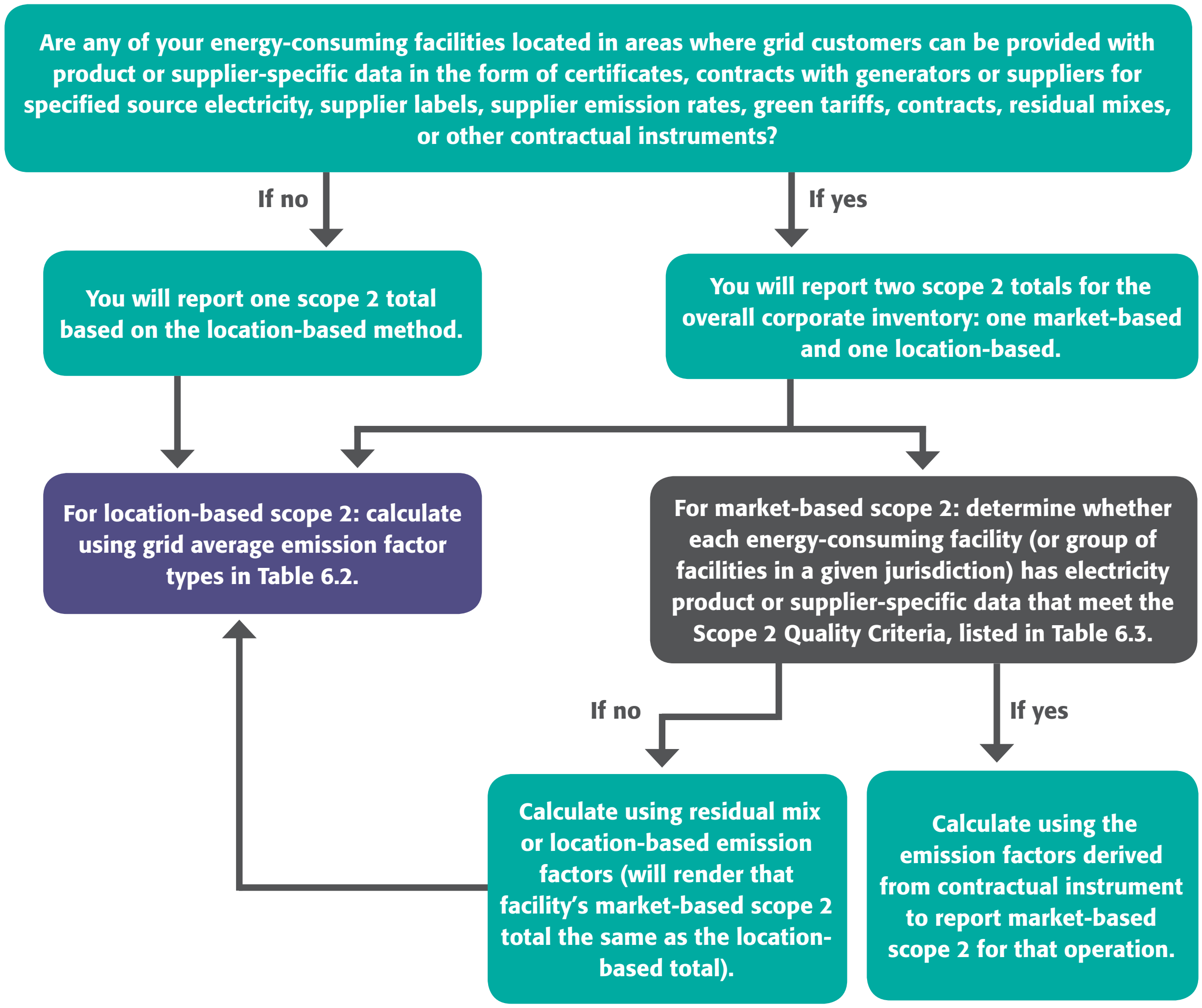
The creation of a certificate that conveys an energy generation attribute claim means that the underlying power—sometimes called "null power"—can no longer be considered to contain the energy attributes, including the type of energy (e.g., that it is "renewable") and its GHG emission rate (that it is zero emissions/MWh). By the conveyance of energy attributes or certificates to a third party separate from the electricity, users of the null power electricity cannot claim to be buying or using renewable energy in the absence of owning the certificate. Instead, companies consuming energy from owned/operated facilities or direct-line transfers where certificates are sold off, **shall** calculate that consumption using other market-based method emission factors such as "replacement" certificates, a supplier-specific emission rate, or residual mix (for the market-based method total) and the grid average emission factor (for the location-based total).

6.4.1 How certificate sales affect on-site energy consumption in the location-based method

Companies who are consuming energy directly from a generation facility that has sold certificates (either owned/operated equipment or a direct line) forfeit not only the right to claim those emissions in the market-based method (requiring the use of some other market-based data source such as other "replacement" certificates, a supplier-specific emission factor, or residual mix) but also the right to claim that emissions profile in the location-based method. Overall, the location-based method is designed to show emissions from the production supporting the local consumption without reference to any contractual relationships. However, the attributes contained in certificates usually carry legally enforceable claims, which should take precedence.

For instance, the U.S. Federal Trade Commission Green Guides[2] prevent any kind of claim about using, consuming,

Figure 6.1 **Determining which accounting methods to use for scope 2**



or hosting renewable energy or its attributes if the REC from that production has been sold off. This includes a claim in the form of location-based calculations of "zero emissions power consumption." Therefore, in the event of certificate sales from owned/operated energy production and consumption, companies should still use the location-based emission factor hierarchy (see Table 6.2).

Taken to its logical conclusion, these kind of legally enforceable rights and claims could call into question the validity of any kind of location-based reporting (since even a grid average will include a mix of power whose RECs have been claimed by someone else). However, for the purposes of a GHG inventory, location-based accounting and reporting are still required in order to improve comparability across multiple markets over time and to show risks/opportunities that are better evaluated based on average emissions in a grid. Companies should avoid using location-based totals for goal tracking where certificates convey these claims and/or carry legally enforceable claims.

6.5 Choose emission factors for each method

Companies should use the most appropriate, accurate, precise, and highest quality emission factors available for each method. Table 6.2 indicates these preferences for the location-based method, and Table 6.3 for the market-based method. Table 6.3 does *not* represent a preferred hierarchy

Table 6.1 Accounting for scope 2 with and without certificates sales

	Scope 2 with location-based method	Scope 2 with market-based method
Energy consumed from owned/operated generation (e.g. a company owns a solar panel and consumes the energy)		
No certificates generated or sold	No scope 2 reported for consumption from owned generation	
Certificates from generation facility retired/retained by the generation facility's owner who consumes the energy	Should report certificate retention separately, but no scope 2 reported for consumption of on-site generation	
Certificates sold to 3rd party	Use location-based emission factor hierarchy	Use market-based emission factor hierarchy
Direct line (e.g. a company receives power directly from a generator, with no grid transfers)		
No certificates generated or sold	Use source-specific emission factor from direct line	
Certificates from generation facility purchased and retired/retained by the energy consumer	Use source-specific emission factor from direct line (same as certificate emission factor)	Use certificate emission factor (same as source- specific emission factor)
Certificates sold to 3rd party	Use location-based emission factor hierarchy	Use market-based emission factor hierarchy
Grid-distributed		
No certificates generated or sold from any generation facilities on the grid	Use location-based emission factor hierarchy	Use market-based emission factor hierarchy
Certificates purchased from grid generation facilities, or included in a supplier-specific emission factor	Use location-based emission factor hierarchy	Use market-based emission factor hierarchy
Certificates from grid generation facilities sold to 3rd parties	Use location-based emission factor hierarchy	Use market-based emission factor hierarchy

of procurement methods (e.g., purchasing renewable energy from a supplier vs. through a contract with a generator), as these are dependent on local market options and company-specific conditions. Instead, it represents a hierarchy of instruments based on the most precise (e.g., energy attribute certificates issued in units that match consumption units, e.g. MWh) to least precise (averages of attributes representing all unclaimed production in a region).

Companies using the market-based method **shall** ensure that any contractual instrument from which an emission factor is derived meets the Scope 2 Quality Criteria listed in Chapter 7. Where contractual instruments do not meet the Scope 2 Quality Criteria requirements, and no other market-based method data are available, the location-based data should be used.

Table 6.2 Location-based method emission factor hierarchy

Data forms listed here should convey combustion-only (direct) GHG emission rates, expressed in metric tons per MWh or kWh.

Emission factors	Indicative examples
Regional or subnational emission factors *Average emission factors representing all electricity production occurring in a defined grid distribution region that approximates a geographically precise energy distribution and use area. Emission factors **should** reflect net physical energy imports/exports across the grid boundary.*	eGRID total output emission rates (U.S.)[a] Defra annual grid average emission factor (U.K.)[b]
National production emission factors *Average emission factors representing all electricity production information from geographic boundaries that are not necessarily related to dispatch region, such as state or national borders. No adjustment for physical energy imports or exports, not representative of energy consumption area.*	IEA national electricity emission factors[c]

Notes:

a Although eGRID output rates represent a production boundary, in many regions this approximates a consumption or delivery boundary, as eGRID regions are drawn to minimize energy imports/exports. See: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

b See Defra: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/224437/pb13988-emission-factor-methodology-130719.pdf.

c IEA emisison factors do not adjust for imports/exports of energy across national boundaries. See: http://data.iea.org/ieastore/product.asp?dept_id=101&pf_id=304.

Table 6.3 Market-based scope 2 data hierarchy examples

Data forms listed here should convey combustion-only (direct) GHG emission rates, expressed in metric tons per MWh or kWh. Reporting entities should ensure that market-based method data sources meet Scope 2 Quality Criteria. Instruments listed here are not guaranteed to meet Scope 2 Quality Criteria, but are indicative of instrument type.

Emission factors	Indicative examples	Precision
Energy attribute certificates or equivalent instruments (unbundled, bundled with electricity, conveyed in a contract for electricity, or delivered by a utility)	• Renewable Energy Certificates (U.S., Canada, Australia and others) • Generator Declarations (U.K.) for fuel mix disclosure • Guarantees of Origin (EU) • Electricity contracts (e.g. PPAs) that also convey RECs or GOs • Any other certificate instruments meeting the Scope 2 Quality Criteria	Higher
Contracts for electricity, such as power purchase agreements (PPAs)[a] and contracts from specified sources, where electricity attribute certificates do not exist or are not required for a usage claim	• In the U.S., contracts for electricity from specified nonrenewable sources like coal in regions other than NEPOOL and PJM • Contracts that convey attributes to the entity consuming the power where certificates do not exist • Contracts for power that are silent on attributes, but where attributes are not otherwise tracked or claimed	
Supplier/Utility emission rates, such as standard product offer or a different product (e.g. a renewable energy product or tariff), and that are disclosed (preferably publicly) according to best available information	• Emission rate allocated and disclosed to retail electricity users, representing the entire delivered energy product (not only the supplier's owned assets) • Green energy tariffs • Voluntary renewable electricity program or product	
Residual mix (subnational or national) that uses energy production data and factors out voluntary purchases	• Calculated by EU country under RE-DISS project [b, c]	
Other grid-average emission factors (subnational or national) – see location-based data	• eGRID total output emission rates (U.S.).[d] In many regions this approximates a consumption-boundary, as eGRID regions are drawn to minimize imports/exports • Defra annual grid average emission factor (UK) • IEA national electricity emission factors[e]	Lower

Notes:

a Because PPAs are the primary example of this type of instrument used in the markets consulted in this TWG process, this class of instrument may be referred to in shorthand as "PPAs" with the recognition that other types of contracts that fulfill a similar function may go by different names.

b See: http://www.reliable-disclosure.org/static/media/docs/RE-DISS_2012_Residual_Mix_Results_v1_0.pdf.

c The Norwegian authority also publishes a residual mix emission factor that can be found here: http://www.nve.no/en/Electricity-market/Electricity-disclosure-2011/.

d See: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

e See: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

6.6 Match emission factors to each unit of electricity consumption

Each unit of electricity consumption should be matched with an emission factor appropriate for that consuming facility's location or market. For the market-based method, this means choosing a contractual instrument or information source for each unit of electricity. For instance, if a company has purchased certificates to apply to half of a given operation's electricity use, it will need to use other instruments or information on the emission factor hierarchy to calculate the emissions for the remaining half.

Companies centrally purchasing energy attribute certificates on behalf of all its operations in a single country or region should indicate how they match these purchases to individual site consumption.

Companies may also use certificates conveyed to them by their supplier, separately from the other supplier mix information. This ensures equivalent treatment of certificates regardless of how they are sourced. For example, a utility delivers 1,000 MWh in total to customers and 200 MWh of that (20 percent) comes from zero-emitting renewables for which the energy attribute certificates have been retired. Any customer of that utility would be able to claim that 20 percent of their electricity is renewable and substantiated with certificates. If Customer A of this utility consumes 2.5 MWh (of the total 1,000 MWh), they can claim 0.5 MWh of renewable energy (of the 200 MWh total) without double counting, but cannot claim any more than this. To cover all of their electricity consumption with zero-emission certificates, Customer A would only need to purchase 2 MWh of renewables on their own.

6.7 Calculate emissions

To calculate scope 2 emissions according to one or both methods, the following procedure applies:

1. Multiply activity data from each operation by the emission factor for that activity for each applicable GHG. Some electricity emission factor sets may include emission rates for CO_2, CH_4, and N_2O; others may only provide CO_2 emission rates (see Box 6.1)
2. Multiply global warming potential (GWP) values by the GHG emissions totals to calculate total emissions in CO_2 equivalent (CO_2e).
3. Report final scope 2 by each method in metric tons of each GHG (where available) and in metric tons of CO_2e.

Example calculations are provided for the location-based method and market-based method in Table 6.4 and Table 6.5, respectively.

Table 6.4 Example calculation for location-based method

Activity data per reporting period			**Emission factors**				**Calculated emissions**			
Facility	Location	Quantity of energy	CO_2 emission rate	CH_4 emission rate	N_2O emission rate	GHG emission factor source	CO_2 (mt)	CH_4 (kg)	N_2O (kg)	CO_2e (mt)
U.S. facilities	eGRID subregion NYUP	2,500 MWh	545.79 lb/MWh	16.3 lb/GWh	7.24 lb/GWh	eGRID year 2010	618.91	18.48	8.21	621.85
	eGRID subregion RFCE	2,500 MWh	1001.72 lbs/MWh	27.07 lb/GWh	15.33 lb/GWh	eGRID year 2010	1135.93	30.70	17.38	1141.96
EU facilities	Denmark	3,000 MWh	0.3152 $mtCO_2$/MWh	*	*	IEA Denmark, 2011	945.63	*	*	945.63
	Belgium	2,000 MWh	0.1957 $mtCO_2$/MWh	*	*	IEA Belgium, 2011	391.44	*	*	391.44
Total consumption		**10,000 MWh**								
Total scope 2 emissions for location-based method							**3091.908**	**49.179**	**25.596**	**3100.87**

* Non-CO_2 emission factors not available for IEA

Table 6.5 Example calculation for market-based method

Activity data per reporting period					**Emission factors**	**Calculated emissions**
Facility	Total energy consumption	Quantity of energy	Contractual instrument type	Meets Scope 2 Quality Criteria?	CO_2e emission rate	CO_2e (mt)
U.S. operations	5,000 MWh	1,000 MWh	PPA with REC retention	Yes Residual mix not available for U.S.	0 mt CO_2e / MWh	0 mt CO_2e
		2,000 MWh	REC purchase (bundled with energy)	Yes Residual mix not available for U.S.	0 mt CO_2e / MWh	0 mt CO_2e
		1,000 MWh	REC purchase (not bundled with energy)	Yes Residual mix not available for U.S.	0 mt CO_2e / MWh	0 mt CO_2e
		1,000 MWh (remaining energy without contractual instruments)	Grid Average (eGRID sub-region NYUP)	Yes Residual mix not available for U.S.	0.5 mt CO_2e / MWh*	500 mt CO_2e
EU operations	5,000 MWh	3,000 MWh	Supplier program	Yes	0.25 mt CO_2e / MWh	750 mt CO_2e
		2,000 MWh	Residual mix (RE-DIS II Belgium 2013)	Yes	0.5 mt CO_2e / MWh	1,000 mt CO_2e
Total energy consumption		**10,000 MWh**				
Total scope 2 emissions for market-based method						**2,250 mt CO_2e**

* Emission factors for CH_4 and N_2O not listed individually here for space considerations

6.8 Roll up GHG emissions data to corporate level

To report a corporation's total GHG emissions, companies will usually need to gather and summarize data from multiple facilities, possibly in different countries and business divisions. It is important to plan this process carefully to minimize the reporting burden, reduce the risk of errors that might occur while compiling data, and ensure that all facilities are collecting information on an approved, consistent basis. Ideally, corporations will integrate GHG reporting with their existing reporting tools and processes, and take advantage of any relevant data already collected and reported by facilities to division or corporate offices, regulators, or other stakeholders. The two basic approaches to gather data on GHG emissions from facilities include a centralized and decentralized approach. For more guidance on this process, see Chapter 6 of the *Corporate Standard.*

6.9 Optional: Calculate any avoided emissions and report separately

Companies can report the estimated grid emissions avoided by low-carbon energy generation and use, separately from the scopes. This type of analysis reflects the impacts of generation on the rest of the grid: for example, the emissions from fossil-fuel or other generation backed down or avoided due to the low-carbon generation. These avoided emissions estimations inherently represent impacts *outside* the inventory boundary. Avoided emissions estimations are not necessarily equivalent to global emissions reductions from additional projects and should therefore not be used to reduce a company's footprint. However, quantifying avoided emissions provide several technical and strategic benefits, including:

- Identifying where low-carbon energy generation can have the biggest GHG impact on system, based on the operating margin.
- Demonstrating that grid-connected generation provides a system-wide service in addition to conveying a specific emission rate at the point of production.

This estimation should follow project-level methodology; see GHG Protocol *Project Protocol* or *Guidelines for Grid-Connected Electricity Projects.* This may be most beneficial where a company has taken actions that avoid higher-carbon generation dispatch at the margins. These actions could include:

- Installing a low-carbon energy generation facility on-site that sells energy to the grid (any emissions from owned/operated facilities are reported in scope 1)
- Installing a cogeneration facility providing both heat and electricity outputs, which may increase a company's scope 1 reporting but reduce the electricity it needs to purchase from the grid
- Securing a contract to purchase power from a *new* low-carbon energy generation facility
- Undertaking a significant energy efficiency effort.

However, if the project operates in a jurisdiction with an emissions cap on the power sector, or comes from an energy generation facility also producing verified emission reductions (also termed a GHG offset), the company should not make public claims about avoided emissions. The avoided grid emissions will either be zero, in the case of a cap as regulated entities may emit up to the level of the cap,[3] or already represented in claims by the offset purchaser. Any offsets produced from the project, or any voluntary allowances retired on behalf of the purchase associated with the project, should be reported separately.

6.10 Location-based emission factors

The emission factors necessary to estimate location-based scope 2 emissions include GHG emission intensity factors for energy production in a defined local or national region. Where advanced studies or real-time information is available, companies may report scope 2 estimations separately as a comparison to location-based grid average estimation (see Box 6.2). Companies should be aware of the following caveats about location-based emission factors:

- **Location-based is not supplier-specific.**
  The location-based grid average emission factors should be distinguished from supplier-specific information, even if the electricity supplier is the sole energy provider in a region and produces a supplier-specific emission factor that closely resembles the overall regional grid average emission factor. In these cases, the service territory may still be a smaller region than the grid distribution area serving a given site of consumption; conversely, many utilities are in competitive markets where multiple suppliers can compete to serve consumers in the same region. Therefore, this method only looks at a broader grid emissions profile serving the local load, regardless of supplier relationships.

- **Grid average emission factors do not factor out contractual purchases.**
  Grid average emission factors in the location-based method should *not* reflect any adjustments or removals for market-based contractual claims by suppliers or end-users. By contrast, a residual mix in the market-based method should represent all unclaimed energy emissions, which is formulated by removing contractual claims data from energy production data (often the same as grid average data).

- **Grid average emission factors are different from marginal grid emission factors.**
  Grid average emission factors should represent all the emissions from energy generation occurring within a defined geographic region, and thereby best represent the purpose of the location-based method. By contrast, marginal emission factors only represent the emissions from those power plants operating "at the margin," which can be more useful for avoided emissions analyses. Companies **shall not** use marginal emission factors such as those provided by CDM for a location-based scope 2 calculation.

Box 6.2 Advanced grid studies

Companies may have access to detailed studies or software solutions linking their facility's time-of-day energy use patterns to the GHG emissions from local generation dispatching during those times. This emission data could be compiled over the course of a year for a consumer to record, match against temporal usage by location, and calculate scope 2 emissions. To date such studies or analyses have not been widely available or used, and have often been contained in proprietary databases with limited consumer access. However, the root components of this type of GHG emissions data, including facility-specific generation and emissions information, are becoming increasingly common as smart grid applications and distributed generation grow. This data can help inform specific demand-side actions more than grid-average emission factors, which may only incentivize overall demand reduction rather than targeted actions. For instance, while utilities may implement DSM measures in order to mitigate emissions, those consumers' demand-timing choices have not been commonly linked to that consumer's GHG emissions, even as those choices may be linked to pricing.

6.10.1 Grid average emission factors

The term "grid average" emission factors reflects a short-hand for a broad category of data sets that characterize all the GHG emissions associated with the quantity of electricity generation produced from facilities located within a specified geographic boundary. Many of these data sets have been compiled for purposes other than corporate accounting and can vary in their inclusion of energy-generation emissions (e.g., which GHG gases are included, and how biomass and CHP emissions are treated) and perhaps most significantly, in the spatial facility-inclusion boundaries. Greater consistency in grid average emission factors globally can improve location-based inventory results that encompass multiple global operations parameters. A simplified illustration of the type of data aggregation and calculation that contributes to a grid average emission factor is shown in Table 6.6.

- **Spatial boundaries.**
  The most appropriate spatial boundaries for emission factors serving the location-based method are those that approximate regions of energy distribution and use, such as balancing areas. All generation and emissions data within this boundary should be aggregated and any net physical energy imports/exports and their related emissions should be taken into account. For multi-country regions with frequent and significant exchanges of energy throughout a year (as measured by percent of that country's total generation), a multi-country regional grid average may be a better estimate than a production-only national emission factor without energy imports/exports adjustments. In turn, in a country with multiple distribution or balancing areas, these subnational regions would be a more precise spatial boundary for grid average emissions.

- **Other data quality.**
  Companies can evaluate emission factor data based on quality indicators including their reliability, completeness, and geographic, temporal, and technological representativeness. Grid-average emission factors in particular may face challenges with temporal representativeness due to time delays between the year in which energy generation and resulting emissions occurred, and the year in which the data is published and made available to users. For U.S. eGRID or IEA, these delays can be 2–3 years. This delay can make grid average emissions factors a less relevant indication of corporate performance or risk assessment when analyzed in the inventory year. Companies should take this into account when analyzing location-based scope 2 results.

6.11 Market-based emission factors data

Under the market-based method, different contractual instruments become carriers of GHG-emission rate information that function as emission factors for consumers to use to calculate their GHG emissions. To ensure this, instruments **shall** include the GHG emission rate attribute. If companies have access to multiple market-based emission factors for each energy-consuming operation, they should use the most precise for each operation based on the list in Table 6.3.

6.11.1 Energy attribute certificates

Certificates form the basis of energy attribute tracking in the market-based method, often being conveyed with contracts for energy and integrating into supplier-specific emission rates. See Chapter 10 for more background on certificate types and treatment.

Table 6.6 Example of grid average emission factor calculation

	Emissions from generation	Total generation in MWh
Energy Facility A (coal)	50,000 metric tons CO_2e	55,000
Energy Facility B (natural gas)	10,000 metric tons CO_2e	30,000
Energy Facility C (wind farm)	0 metric tons CO_2e	15,000
Totals within defined boundary	60,000 metric tons CO_2e	100,000
Total system emission rate ("grid average")	60,000 metric tons CO_2e/100,000	**0.6 mt CO_2e /MWh**

6.11.2 Contracts such as power purchase agreements (PPAs)

These types of contracts allow a consumer, typically larger industrial or commercial entities, to form an agreement with a specific energy generator. The contract itself specifies the commercial terms, including delivery, price, payment, etc. In many markets, these contracts secure a long-term stream of revenue for an energy project.

Where certificates are issued: In these cases, the certificates themselves serve as the emission factor for the market-based method. If the certificates are bundled with the contract, the purchaser can claim the certificates. If the certificates are sold separately, the power recipient *cannot* claim the attributes of the specific generator.

When certificates are not used in the jurisdiction or for the technology/resource: Where certificates are not issued by a tracking system, a PPA may nevertheless convey generation attributes if the PPA includes language that confers attribute claims to the power recipient. This more explicitly renders the PPA a GHG attribute-claims carrier. Where the PPA is silent on attributes and where attributes are not otherwise conveyed or tracked, the contract for power can be used as a proxy for delivery of attributes. As shown in the Scope 2 Quality Criteria, an audit trail or other mechanism is needed to demonstrate that no other entity is claiming the attributes from this generation.

When the power received in the PPA is resold: If the power purchased in a PPA is resold to the wholesale or retail market, then the company receiving-and-reselling the power cannot claim the "use" of the attributes in markets where certificates are not used. In markets with certificates, the company may retain the certificates from the power generation to use for its own claims while it resells the power.

To avoid double counting, companies making claims based on contracts (where no certificate system exists) should report the quantity of MWh and the associated emissions acquired through contracts to the entity that calculates the residual mix, and request that their purchase be excluded from the residual mix. Certain third-party certifications of renewable energy may do this automatically.

6.11.3 Supplier-specific emission rate

Electricity suppliers or load-serving entities function differently across markets. In some deregulated markets, there may be retail competition within the group of entities that interface directly with customers. In other regulated monopoly markets, a single utility may supply an entire service territory. In all cases, an energy supplier can provide information to its consumers regarding the GHG intensity of delivered electricity. The utility or supplier-specific emission factor may be a standard product offer or a differentiated product (e.g. a renewable energy product or tariff). When using a supplier-specific emission factor, companies should seek to ensure that:

- The emission rate is disclosed, preferably publicly, according to best available information, and where

Box 6.3 How the UK implements EU supplier disclosure requirements

In the EU system, the Fuel Mix Disclosure regulations require all suppliers to disclose the emissions associated with the power that they supply. To do so, U.K. suppliers present renewable energy guarantees of origin (REGOs) and Generator Declarations to the regulator for the jurisdiction, the Department for Energy and Climate Change (DECC). DECC then removes all claimed generation from the overall national average, which leads to the production of a 'residual' energy mix—with an associated emissions factor. This is issued to all suppliers so that they can complete their calculations for any of their supply without certificates. This combination of verified supplier claims and allocation of the remaining emissions back to suppliers ensures consistency across suppliers and accounting for all generation emissions.

For more on U.K. requirements, see: https://www.ofgem.gov.uk/ofgem-publications/57972/12340-28205.pdf and https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/82783/Fuelmixdisclosure2013.pdf.

possible using best practice methods such as The Climate Registry Electric Power Sector Protocol. Methods for calculating and disclosing the mix and related attributes may also be specified by regulation.

- That the utility or supplier discloses whether and how certificates are used in the emission factor calculation, unless there is third-party certification of the utility product. In particular, companies should seek to ensure that if the supplier has a differentiated product (e.g. a renewable energy product or tariff), the certificates or other contracts used for that product should be used only for that product and not counted in the standard product offer.
- That the supplier-specific emission factor includes emissions from all the energy delivered by the utility, not just the generation assets owned by the supplier (e.g. what is required by some fuel mix disclosure rules). Many suppliers purchase significant portions of their energy from other generators via contracts, or through the spot market. The emission factor should reflect the emissions from all of these purchases. A supplier-specific emission rate can also reflect certificates retired for compliance purposes (such as U.S. state RPS programs) which also convey attributes for public benefit and claims.

Consumers should not attempt to calculate a supplier-specific emission rate themselves based on a fuel mix disclosure due to the variations in fuel mix disclosure rules, which may reduce the accuracy of the resulting GHG emission factor.

If an electricity supplier purchases offsets on behalf of their customers, the reporting customers should report the offsets separately from the scopes. The supplier-specific emission rate used for scope 2 should reflect supply only, and not purchased offsets.

6.11.4 Residual mix

To prevent double counting of GHG emission rate claims tracked through contractual instruments, the market-based method requires an emission factor that characterizes the emission rate of untracked or unclaimed energy. This emission factor creates a complete data set under the market-based method, and represents the regional emissions data that consumers should use if they operate in a market with choice for consumers, differentiated products, and supplier specific data, but did not purchase certificates or a specified product, do not have a contract with a specified source, or do not have supplier-specific information.

Depending on the region and percentage of tracked electricity, this residual mix may closely resemble a "grid average" data set, or may be significantly different. In the U.S. overall, an estimation of the adjusted mix in 2009 did not differ significantly from the location-based grid average data. In fact, according to a paper by the Environmental Tracking Network of North America (ETNNA 2010), the difference is currently less than one half of one percent.[4]

Companies should not attempt to calculate their own residual mix.

- **If a residual mix is not available.** Other unadjusted grid average emission factors such as those used in the location-based method may be used. Companies

shall document in the inventory that a residual mix was not available.

6.12 Treatment of biofuel emissions

Biogenic materials—including biomass, biofuels, and biogas—are increasingly used as a resource for energy generation on-site and on the grid. While biomass can produce fewer GHG emissions than fossil fuels and may be grown and used on a shorter time horizon, it still produces GHG emissions and should not be treated with a "zero" emission factor. Based on the *Corporate Standard,* any CH_4 or N_2O emissions from biogenic energy sources use **shall** be reported in scope 2, while the CO_2 portion of the biofuel combustion **shall** be reported outside the scopes. In practice, this means that any market-based method data that includes biofuels should report the CO_2 portion of the biofuel combustion separately from the scopes.

For the location-based approach, most commonly used grid average emission factor—including those issued by EPA eGRID (U.S.), Defra (U.K.), and the International Energy Agency (for all countries worldwide)—do not note the percentage of biomass in the emission factor and do not separately report the biogenic CO_2, effectively treating it as "zero" emissions. Companies should document this omission in any grid average emission factors used.

Endnotes

1. See Chapter 14 of The Climate Registry's General Reporting Protocol.
2. See http://www.ftc.gov/news-events/media-resources/truth-advertising/green-guides.
3. See Chapter 10 on how to report this relationship. Allowance set-aside programs also allocate and retire allowances to restore an avoided emissions claim. In this case, where a set-aside for voluntary renewable energy is in place and where allowances have been retired, purchasers can make claims about avoided emissions.
4. ETNNA (2010). P. 14

7 Accounting and Reporting Requirements

This chapter identifies all the new accounting and reporting requirements introduced by this Guidance. Conformance with this Guidance is required in order to prepare an inventory in conformance with the *Corporate Standard*.

This Guidance provides a new set of requirements applied to the *Corporate Standard* in calculating and reporting scope 2 emissions. Therefore, conformance with this Guidance is required in order to prepare an inventory in conformance with the *Corporate Standard*. In addition to all existing *Corporate Standard* accounting and reporting requirements (see Chapter 9 of the *Corporate Standard*), companies **shall** calculate and report scope 2 in the following ways:

7.1 Required information for scope 2

For companies with operations only in markets that do not provide product or supplier-specific data or other contractual instruments:

- Only one scope 2 result **shall** be reported, based on the location-based method.

For companies with any operations in markets providing product or supplier-specific data in the form of contractual instruments (Markets are increasingly developing and refining purchasing options, and the list is not exhaustive. Currently this includes the EU Economic Area, the U.S., Australia, most Latin American countries, Japan, and India, among others.)

- Companies **shall** account and report scope 2 emissions in two ways and label each result according to the method: one based on the location-based method, and one based on the market-based method.
- Many companies' GHG inventories will include a mix of operations globally, some where the market-based method applies and some where it does not. Companies **shall** account for and report all operations' scope 2 emissions according to both methods.
    - To do so, emissions from any operations in locations that do *not* support a market-based method approach **shall** be calculated using the location-based method (making such operations' results identical for location-based and market-based

methods). Companies should note what percentage of their overall electricity consumption reported in the market-based method reflects actual markets with contractual information.

Scope 2 Quality Criteria. Companies **shall** ensure that any contractual instruments used in the market-based method total meet the Scope 2 Quality Criteria specified in Table 7.1. If instruments do not meet the Criteria, then other data (listed in Table 6.3) **shall** be used as an alternative in the market-based method total. In this way, *all* companies required to report according to the market-based method will have some type of data option.

- Companies **may** provide a reference to an internal or external third-party assurance process, or assurance of conformance provided by a certification program, supplier label, green power program, etc. An attestation form **may** be used to describe the chain of custody of purchased certificates or other contractual instruments.
  - If a residual mix is not currently available, reporters **shall** note that an adjusted emissions factor is not available or has not been estimated to account for voluntary purchases and this may result in double counting between electricity consumers.

Inventory totals. For companies adding together scope 1 and scope 2 for a final inventory total, companies **may** either report two corporate inventory totals (one reflecting each scope 2 method), or **may** report a single corporate inventory total reflecting one of the scope 2 methods.

- If reporting a single corporate inventory total, the scope 2 method used should be the same as the one used for goal setting. Companies **shall** disclose which method was chosen for this purpose.

Table 7.1 Scope 2 Quality Criteria

Further explanation on select Scope 2 Quality Criteria can be found in Section 7.5.

All contractual instruments used in the market-based method for scope 2 accounting shall:
1. Convey the direct GHG emission rate attribute associated with the unit of electricity produced. 2. Be the only instruments that carry the GHG emission rate attribute claim associated with that quantity of electricity generation. 3. Be tracked and redeemed, retired, or canceled by or on behalf of the reporting entity. 4. Be issued and redeemed as close as possible to the period of energy consumption to which the instrument is applied. 5. Be sourced from the same market in which the reporting entity's electricity-consuming operations are located and to which the instrument is applied.
In addition, utility-specific emission factors shall:
6. Be calculated based on delivered electricity, incorporating certificates sourced and retired on behalf of its customers. Electricity from renewable facilities for which the attributes have been sold off (via contracts or certificates) shall be characterized as having the GHG attributes of the residual mix in the utility or supplier-specific emission factor.
In addition, companies purchasing electricity directly from generators or consuming on-site generation shall:
7. Ensure all contractual instruments conveying emissions claims be transferred to the reporting entity only. No other instruments that convey this claim to another end user shall be issued for the contracted electricity. The electricity from the facility **shall not** carry the GHG emission rate claim for use by a utility, for example, for the purpose of delivery and use claims.
Finally, to use any contractual instrument in the market-based method requires that:
8. An adjusted, residual mix characterizing the GHG intensity of unclaimed or publicly shared electricity shall be made available for consumer scope 2 calculations, or its absence shall be disclosed by the reporting entity.

Methodology disclosure. Companies **shall** disclose methods used for scope 2 accounting. For the market-based method, companies **shall** disclose the category or categories of instruments from which the emission factors were derived, where possible specifying the energy generation technologies.

Base-year information. Companies **shall** disclose the year chosen as the base year; the method used to calculate the base year's scope 2 emissions; whether historic location-based data is used as a proxy for a market-based method; and the context for any significant emission changes that trigger base-year emissions recalculation (acquisitions/divestitures, outsourcing/insourcing, changes in reporting boundaries or calculation methodologies, etc.)

Disclose basis for goal setting. If a company sets a corporate inventory reduction goal and/or a scope 2-specific reduction goal, the company **shall** clarify whether the goal is based on the location-based method total or market-based method total.

7.2 Recommended disclosure

Annual electricity consumption. Companies **should** report total electricity, steam, heat, and cooling per reporting period separately from the scopes totals (in kWh, MWh, BTU, etc.), which should include all scope 2 activity data as well as the quantity of energy consumed from owned/operated installations (which may be only reported in scope 1 and not in scope 2.)

Biogenic emissions. Companies **should** separately report the biogenic CO_2 emissions from electricity use (e.g. from biomass combustion in the electricity value chain) separately from the scopes, while any CH_4 and N_2O emissions should be reported in scope 2.

- Companies **should** document if any GHG emissions other than CO_2 (particularly CH_4 and N_2O) are not available for, or excluded from, location-based grid average emissions factors or with the market-based method information.

Other instrument retirement. Companies **should** disclose additional certificate or other instrument retirement performed in conjunction with their voluntary claim, such as with certificate multipliers or any pairing required by regulatory policy.

Basis for upstream scope 3. The reporting entity **should** identify which methodology has been used to calculate and report scope 3, category 3—upstream energy emissions not recorded in scope 1 and 2, scope 3.

Instrument features. Where relevant, companies **should** disclose key features associated with their contractual instruments claimed, including any instrument certification labels that entail their own set of eligibility criteria, as well as characteristics of the energy generation facility itself and the policy context of the instrument. These features are elaborated in Chapter 8.

Role of corporate procurement in driving new projects. Where relevant, companies **should** elaborate in narrative disclosure how any of the contractual instruments claimed in the market-based method reflect a substantive contribution by the company in helping implement new low-carbon projects.

7.3 Optional information

Scope 2 totals disaggregated by country. This can improve transparency on where market-based method totals differ from location-based.

Avoided emissions estimation. Consistent with Chapter 8 of the *Corporate Standard,* companies **may** separately report an estimation of GHG emissions avoided from a project or action (also see Section 6.9). This quantification should be based on project-level accounting, with methodologies and assumptions documented (including to what the reduction is being compared). See the *GHG Project Protocol* and *GHG Protocol Guidelines for Grid-Connected Electricity Projects* for example methodologies.

Advanced grid study estimations. Where advanced studies (or real-time information) are available, companies **may** report scope 2 estimations separately as a comparison to location-based grid average estimations, and companies can document where this data specifically informed efficiency decision making or time-of-day operations. Because these studies or analyses may be more difficult to use widely across facilities or to standardize/aggregate

consistently without double counting, companies should ensure that any data used for this purpose has addressed data sourcing and boundaries consistent with the location-based method.

Scope 2 results calculated by other methods. If companies are subject to mandatory corporate reporting requirements for facilities in a particular region/nation that specify methodologies other than the two required for dual reporting, these companies **may** report these results separately from the scopes.

Disclose purchases that did not meet Scope 2 Quality Criteria. If a reporting entity's energy purchases did *not* meet all Scope 2 Quality Criteria, the entity **may** note this separately. This note should detail which Criteria have been met, with details of why the remaining Criteria have not. This will provide external stakeholders with the information they require, and allow the reporting entity to disclose the efforts made to adhere to the guidance. (As noted in Chapter 6, location-based method data will be used as proxy emission factors in the market-based method total.)

See the *Corporate Standard* Chapter 9 for more information about optional information and how to use ratio indicators and other performance metrics in reporting.

7.4 Dual reporting

Dual reporting allows companies to compare their individual purchasing decisions to the overall GHG-intensity of the grids on which they operate. In addition, reporting two separate scope 2 figures using two different methods provides several benefits:

- Distinguishes changes in choices vs. changes in grid emissions intensity
- Provides for a more complete assessment of the GHG impact, risks, and opportunities associated with energy purchasing and consumption
- Provides transparency for stakeholders
- Improves comparability across operations (on location-based method) where the company's GHG inventory includes operations in markets *without* contractual instruments
- Facilitates participation in programs with different reporting requirements.

This guidance's framework addresses and reduces double counting between scope 2 inventories when using the same accounting method, improving the accuracy of reported results and ensuring clear performance tracking toward goals.

The UK represents an example of the differing demands of the various stakeholders, where organizations (especially those trading internationally) have complex demands from their stakeholders. The carbon inventory is often reviewed by investors based in the United States, where there is an expectation to report using the market-based approach. However, the prevailing guidance from the UK government is to report using the locational-based approach, in part due to concerns regarding subsidy levels for renewables and double counting concerns. For these organizations, dual reporting provides disclosure in a way that allows all stakeholders to be satisfied.

7.4.1 Other methods

Some jurisdictions may recommend methods other than the location-based or market-based method as the basis for its consumer claims and scope 2 accounting, in order to achieve specific policy objectives. For instance, Ademe[1] in France has calculated different grid GHG emission rates according to different end uses by consumers. This represents a different emissions allocation approach than the location-based method presented in this guidance, although it is derived from it. It recommends companies reporting to Ademe apply these end-use factors to the different types of energy end uses, in order to better estimate the average GHG impact of specific consumption activities.

Companies required by regulation to use a method other than those listed in this guidance should do so for those required reports. To maintain consistency with the GHG Protocol *Corporate Standard* and this *Scope 2 Guidance,* companies may additionally and separately report any scope 2 totals calculated for other mandatory reporting rules applying to that region/nation's facilities.

7.4.2 Gross/net reporting

The two method totals (location-based and market-based) should not be viewed as "gross/net," since a net calculation typically implies that external reductions such as offsets have been applied to the inventory. While many contractual instruments in the market-based method represent a zero emission rate from renewable energy and generally serve to lower the GHG intensity of the reporter's electricity use, the market-based method should also include other contractual instruments representing fossil fuel or mixed-resource emission factors as well. The method is designed to reflect a range of instruments that together allocate overall emissions across the grid. For instance, a supplier-specific emission rate that includes a mix of generation technologies also is a valid market-based method emission factor.

However, companies can report avoided emissions estimations from generation separately from the scopes and indicate if these have been used in program-specific gross/net reporting (such as Defra Corporate guidelines[2]).

7.5 Additional guidance on Scope 2 Quality Criteria

The environmental integrity of the market-based method depends on ensuring that contractual instruments reliably and uniquely convey GHG emission rate claims to consumers. Without this, a resulting market-based scope 2 total lacks the accuracy and consistency necessary to drive corporate energy procurement decisions. In addition, the lack of a reliable system for tracking or assuring claims poses risks of inaccurate consumer claims regarding a product's actual attributes, and weakens the ability for consumer decisions to influence market supply.

Therefore, this guidance identifies a set of minimum criteria that relate to the integrity of the contractual instruments as reliable conveyers of GHG emissions rate information and claims, as well as the prevention of double counting. They represent the *minimum* features necessary to implement a market-based method of scope 2 GHG accounting. *Programs or jurisdictions may have additional requirements that reporting entities should consult and follow.*

Criteria 1. Conveying GHG emission rate claims. Many instruments already include specific language about the ownership or ability to claim specific attributes about the product (energy) being generated. In the U.S., most states (and the Green-e Energy National Standard) define RECs as conveying "all environmental attributes" associated with the MWh of energy generation. This type of claim is considered "fully aggregated," meaning that no other instrument can be generated from that MWh which conveys consumer claims regarding any of the environmental attributes of the energy. (In specific cases of multipliers or issuance of multiple instruments from the same MWh, then all instruments **shall** be retired for a full claim on that MWh.) Tracking systems themselves support only fully aggregated certificates.

In some markets it may be possible for attribute claims about energy generation to be separated out explicitly into different certificates that could be used for different purposes. This guidance does not address program design elements in markets with multiple certificates, but requires that only one instrument (or discrete set of instruments applied all at once) convey attribute claims about the energy type and its GHG emission rate.

If certificates do not specify attributes: Certificates that do not currently specify what, if any, energy attribute claims are conveyed, may still convey a claim implicitly through proving the second point: that no consumer is claiming the same energy generation attributes. Evidence of this may be achieved through attestations from each owner in the chain of custody or equivalent procedures providing the same information.

If the attribute emission rate itself is not specified and the technology is not zero emissions, the reporting organization should seek from the generating entity a specific emission rate from that generation facility. Otherwise, a default factor from IPCC or other government publications may be used and disclosed.

Biofuel generation facilities producing certificates should specify the CO_2, CH_4, and N_2O emissions produced at the point of generation. The scope 2 reporter reports the CH_4 and N_2O emissions in scope 2, while the CO_2 from biofuel is reported separately from the scopes.

Criteria 2. Unique claims. If other instruments exist that can be used for attribute claims by other electricity consumers, companies must ensure that the one being used by the reporting entity for a GHG emission rate claim is the only and sole one that does so. Where multiple instruments carry the GHG emission rate attribute claim, some jurisdictions or programs may require acquisition and "pairing" of the multiple certificates to support a voluntary consumer GHG emission rate claim. Companies should check with their electricity supplier or relevant policy-making bodies to ensure that the certificates are claimed, paired, or retired in compliance with applicable jurisdictional or program requirements.

The underlying electricity (or megawatt-hour) minus the instrument, sometimes called "null power," **shall** also not reflect the same GHG emission rate, but should be assigned residual mix emissions for the purpose of delivery and/or use claims in the market-based method.

In some cases, ensuring unique GHG emission rate claims may require arbitration regarding the validity and enforceability of a claim where multiple instruments exist and remain unclear on attribute claims.

Criteria 3. Retirement for claims. Ensuring that instruments are retired, redeemed, or claimed to support a consumer claim can be done through a tracking system, an audit of contracts, third-party certification, or may be handled automatically through other disclosure registries, systems, or mechanisms. These practices help guarantee that only consumers make a claim, even as an instrument may change hands through trading.

Criteria 4. Vintage. Vintage reflects the date of energy generation from which the contractual instrument is derived. This is different from the age of the facility. In order to ensure temporal accuracy of scope 2 calculations, this criteria seeks to ensure that the generation on which the emission factors are based occurs close in time to the reporting period for which the certificates (or emissions) are claimed. This timing should be consistent with existing standards for the market where the contractual instruments exist. Contractual instruments should clearly display when the underlying electricity was generated.

Criteria 5. Market boundaries. The market boundary criteria address the geographic boundary from which certificates can be purchased and claimed for a given operation's scope 2 accounting and reporting.

Distinguishing other relevant electricity boundaries: The market for purchasing and selling electricity is typically a regional transmission organization, power pool, or balancing area, with exports and imports often broadening these markets. By definition, certificates are separated from underlying electricity flows, and markets for unbundled certificates have often been less constrained than those for electricity itself. This larger market boundary for certificate use promotes broader areas of consumer choice and the building of renewable energy resources in the most economically viable locations.

To determine market boundary: Companies should check whether the regulatory authorities and/or certification/issuing bodies responsible for certificates have established the boundaries in which certificates may be traded and redeemed, retired or canceled, and should follow these market boundaries.

If the market boundary is not specified or not clear: Markets for certificates are typically determined by political or regulatory boundaries rather than just physical grid interconnection. This means market boundaries can be limited to a single country or group of countries that recognize each other's certificates as fungible and available to any consumers located therein. The United States, for example—despite differences in state law, local regulatory policy, and variation in physical interconnection within these regions—operates under broad federal laws and regulations, and therefore has constituted a single market for use of certificates. The EU represents a multi-country market united by a set of common market rules and a regional connection.

Where multiple countries or jurisdictions form a single market, a consistent means of tracking and retiring certificates, and calculating a residual mix, needs to be present in order to prevent double counting of GHG emission rates among electricity consumers. Accurate residual mixes should take into account the energy and emission mixes of all geopolitical entities engaged in trading certificates.

Additional geographic sourcing considerations: In addition, if not already specified by regulation or program, contractual instruments should be sourced from regions reasonably linked to the reporting entity's electricity consumption. These regions may grow over time as more interconnections and larger balancing areas are formed to improve grid reliability and integrate intermittent renewables.

Criteria 6. Supplier or utility-specific emission factors. As part of the calculation, the utility or supplier should disclose whether and how certificates are used in the emission factor calculation, unless there is third-party certification of the utility product. The utility or supplier-specific emission factor may be for:

a. A standard product offer or
b. A differentiated product (e.g., a low-carbon power product or tariff).

The supplier-specific emission factor should be disclosed (preferably publicly) according to best available information. Where possible, this should also follow best practice methods, such as The Climate Registry Electric Power Sector Protocol.

Criteria 7. Direct contracts or purchasing. In the absence of energy attribute certificates, the contract and claim associated with it should be verified by a third party to convey a unique or sole ownership right to claim a GHG emission rate.

Criteria 8. Residual mix. To ensure unique claims by all electricity users, an adjusted, residual mix characterizing the GHG intensity of unclaimed or publicly shared electricity is necessary. This residual mix should be based on combining national or subnational energy and emissions production data with contractual instrument claims. If a residual mix is not currently available, companies **shall** disclose that an adjusted emissions factor is not available or has not been estimated to account for voluntary purchases and this may result in double counting between electricity consumers. Reporters may provide other information about the magnitude of this error, where it is available and where it puts the scale of the residual mix adjustment into a context of other sources of error in grid emission factor calculation.

Endnotes

1. See: http://www.basecarbone.fr/data/rapport_methodo_co2_elec_2012.pdf
2. See: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/206392/pb13944-env- reporting-guidance.pdf

8 Recommended Reporting on Instrument Features and Policy Context

This chapter describes additional information that companies should disclose about the features and policy context of their energy purchases. This disclosure can improve transparency and inform stakeholders.

8.1 Instrument feature disclosure

Markets currently differ as to what types of energy generation facilities produce instruments that are recognized in the market-based method for corporate GHG inventories. Different programs establish their own *eligibility criteria* that determine what energy generation facilities can produce certificates that are recognized in the program. (See Chapter 10 for background on these differences).

This variation can make it difficult to compare and understand the procurement choices a company has made in different markets. However, when companies disclose information about the energy generation facilities and policy context reflected in their contractual instruments, company decision makers and stakeholders can get a clearer picture about how well the purchase aligns with other company goals. In particular, stakeholders evaluating a company's contribution to mitigating global emissions may be interested in how a company is driving change in supply.

If information on these features or policy context is not made available on or with the certificate, companies can ask the certification program, tracking system, or supplier for further information. Lacking other information, a company may disclose the overall criteria identified by the certificate program (e.g. Green-e Energy certified RECs are from facilities installed in the last fifteen years on a rolling basis).

8.1.1 Instrument feature disclosure formats

Companies can disclose features about their contractual instruments in a variety of formats depending on the intended audience, communication channel (summary report vs. full extended report), etc. Companies may find a checklist approach may help maintain clarity on the features associated with each contractual instrument, depending on the number of energy-consuming facilities and different instruments in the inventory. See Table 8.1 for a list of these features and policy contexts. In cases where companies have undertaken strategic or iconic projects, a more narrative format can be useful to highlight the project's features in the context of a larger history.

Table 8.1 Example instrument features and policy context

Instrument labels
Certification or label name (if applicable). This can include certification such as Green-e Energy (U.S.), EcoLogo (Canada), or labels such as EKOenergy and Naturemade in the EU. The certification or label name should also specify what is being certified, e.g. in the U.S. Green-e Energy certifies against a set of requirements described in their National Standard.
Incremental funding programs. This should specify whether the instrument is associated with a certification label or supplier program that contributes incremental funding to new projects, and if so what quantity of funding is included with the company's contractual purchase.
Energy generation facility features
Energy resource type. Instruments should clearly identify the resource generating the certificate. For supplier-specific emission rates, the resource type could be "mix" for standard offers, "multiple renewable" for certain green power products, or cite the specific resource used. Residual mix will typically be a "mix."
Facility location. Depending on the information available from the certificate, supplier, or contract, the generation facility location could be identified at a national or subnational level (either geopolitical such as a U.S. state, and/or a grid region such as a North American Electric Reliability Corporation (NERC) region.
Facility age. Stakeholders may wish to know whether the purchase consists largely of generation attributes from older facilities or more recently constructed projects. Companies should note the year the generation facility that created the certificate/contract was first operational or substantially repowered.
Policy context
Supplier quotas. The contractual instrument claimed will relate differently to instruments used for supplier quotas, depending on the market. Companies should note the relationship between their contractual instruments following the list of options in Table 10.2.
• **Cap and Trade.** Is the facility that produced the instruments you claim affected by a cap and trade policy? (Y/N) • If yes, does the cap and trade program allocate allowances for retirement on behalf of voluntary renewable electricity purchases from this facility? (Y/N) • If yes, were allowances retired on behalf of your voluntary purchase of instruments from this facility? (Y/N) If so, these allowances should be reported (in metric tons) separately from the scopes.
Funding/Subsidy Receipt. The funding disclosed here can highlight recent funding or subsidy policies directly and substantially affecting the generation facility.
Offsets. Is the facility producing offset credits from the same MWh reflected in the contractual instrument? (Not applicable to contractual instruments in most industrialized electricity markets).
Other policy instruments. This includes any other policy instruments bundled/retired voluntarily by the company itself, a certificate certification program, supplier label, etc.

8.2 Reporting on the relationship between voluntary purchases and regulatory policies

This guidance does not require contractual instruments claimed in scope 2 to be "in addition to," or independent from, regulatory policies such as subsidies, tax exemptions, or supplier quotas. Due to the design of renewable energy production targets, achieving "regulatory surplus" with voluntary purchases may not always be possible. For transparency, companies should disclose the relationships between instruments claimed in scope 2 and regulatory policies, as part of the disclosure of overall instrument features and policy context to improve transparency and stakeholder understanding of the voluntary purchase. Companies should also disclose additional certificates or other instrument retirement performed in conjunction with their voluntary claim. These relationships and reporting options are elaborated below.

8.2.1 Relationship to supplier quotas

Where relevant, companies should state the relationship between the energy claimed in the market-based method and any compliance instruments used for supplier quota regulations. Six example relationships can be found in Table 8.2.

8.2.2 Relationship to subsidy receipt

In some countries, renewable energy projects that receive a public subsidy such as a feed-in-tariff (FiT) must have the certificate from that project retired or canceled, preventing any individual consumer claim. For instance, in Germany if a generation facility receives subsidies, then all generation attributes must be either canceled or retired on behalf of all German consumers under the rationale these consumers have paid for the energy through taxes, and should therefore collectively own the attributes. (This is in contrast to other European member states, which allow for individual consumer attribute ownership in addition to national subsidies.) In Japan, once renewable electricity that receives a FiT is sold to utilities, voluntary renewable

Table 8.2 Relationships between voluntary and supplier quotas

Reporting Option	Example
If there is no supplier energy source quota in contractual instrument's market	
1. No supplier quota in instrument's market	
If there is a supplier quota in the jurisdiction of the contractual instrument:	
2. Energy from claimed instrument also used to meet supplier quota	Multiple certificates from same MWh conveying different attributes
If there is a quota and the energy from the claimed instrument is not directly used to meet it:	
3. Claimed instrument not directly reflecting quota	Fossil contract or residual mix
4. Claimed instrument includes the supplier quota	Supplier-specific emission factor that includes compliance instruments
5. Claimed instrument above and beyond supplier quota	Voluntary U.S. RECs
6. Claimed instrument paired with retired compliance instrument issued from same unit of energy generation	*No applied examples to date

energy certificates cannot be issued. Accordingly, for the purpose of achieving regional fairness, the value of zero emissions energy generated from FiT-supported renewable electricity is allocated to each utility in accordance with sales amounts because FiT represents a public subsidy. In practice, this leaves subsidized energy a "public good" whose attributes are included in a system mix used for supplier reporting.

Reporting options: In jurisdictions where energy supported by recent or substantial renewable energy production subsidies is not excluded from voluntary programs or claims, companies should disclose subsidy receipt (available on GO).

8.2.3 Relationship to emissions trading programs

In emissions-capped power programs such as the European Emissions Trading Scheme, low-carbon energy generation is incentivized through creating a limit (cap) on fossil-fuel emissions. But all energy attribute certificates, including voluntary energy attribute certificates and other contractual instruments can still convey emission rate claims under an emissions cap (e.g., renewable energy still produces zero emissions/MWh at the point of generation). The presence of a cap does not directly impact or prevent market-based accounting based on contractual instruments.

However, because the total system's emissions have been predetermined by the cap, these actions may simply "free up" allowances for other emitters to acquire, resulting in no net global GHG reductions. This means consumers cannot claim that the generation purchased resulted in global emission reductions on the grid; only by affecting the allowance cap by retiring or reducing available allowances would electricity consumers be able to support that claim. Voluntary low-carbon energy purchases (as well as other actions such as efficiency upgrades or energy conservation) without allowance retirement could be seen as an essential and expected means of contributing to meeting the system-wide cap, or as "subsidizing" the overall sector's costs for meeting the cap.

Allowance set-asides. Many states participating in the U.S. Regional Greenhouse Gas Initiative (RGGI) and the California cap-and-trade program have created an allowance set-aside program. These programs designate that a portion of total emission allowances available in a given compliance period be set aside and retired on behalf of voluntary REC purchases. This combined REC purchase and allowance retirement is designed to preserve or strengthen the global carbon benefits and impacts for voluntary renewable energy purchases. In theory, allowances could be retired by any entity trying to demonstrate environmental commitment, as a reduction in available allowances for emitting entities can create scarcity (and theoretically, behavior change) in the marketplace. Retiring allowances effectively lowers the cap.

Reporting options. Companies claiming contractual instruments in an emissions-capped power sector should disclose whether an allowance set-aside program is in place, and whether any allowances have been retired along with the voluntary certificates. The tons of GHG emissions represented in any retired allowances should be reported separately from the scopes.

Caveats. This guidance does not recommend treating allowances retired as part of a voluntary renewable energy set-aside as though they were offsets. Conceptually, allowances could be seen to function as offsets in that they represent tons of CO_2e that were avoided compared to what would have happened without the purchase and retirement of the allowance. While the reference case in this analysis would be the emissions cap for the sector, it has not always been clear that this cap inherently represents "what would have happened" and that the allowance retirement is therefore additional. On their own, most emission caps are intended to reduce emissions compared to what would have been occurring in the sector. But in oversupplied allowance markets, where the cap level closely follows or even exceeds what would have been occurring anyway (e.g. during a period of economic downturn), the value of retiring an allowance might be minimized.[1] Further, if allowance retirement becomes common practice and significantly increases the price of allowances, cost containment measures in cap-and-trade policies may be triggered so that regulators increase the total volume of available allowances (and therefore nullify the reduction impacts of the retirement).

8.2.4 Relationship to offset credits

Offsets generated from renewable energy facilities remain a popular project type in offset schemes such as the Clean Development Mechanism (CDM), as well as voluntary standards. These programs are designed to provide a revenue stream that enables a project to be built that—in the absence of the offset sales—would be unfeasible. The offset represents a quantity of global GHG emissions reduced or avoided by the project compared to a baseline scenario of what emissions would have occurred in the absence of the offset-funded project.

Distinguishing attributes and claims. Offsets, and their global avoided emissions claim, represent a different instrument and claim from the energy attributes associated with energy production.[2] Offsets convey tons of avoided CO_2 using project-level accounting, but they do *not* convey information about direct energy generation emissions occurring at the point of production, like contractual instruments do (see Box 4.3). An offset credit does *not* confer any claims about the use of electricity attributes applicable to scope 2. For example, to distinguish avoided emissions and emission rates, a natural gas facility newly established in a largely coal-based grid will *avoid* operating margin emissions as fossil fuel plants with higher operating costs are backed down. But the natural gas plant still emits at a fixed rate (emissions/MWh), which consumers of that energy can document in scope 2.

Box 8.1 Attributes and claims from renewable energy offsets

Offsets are designed to be fungible (or interchangeable) globally, derivable from a variety of project types (forestry, renewable energy, etc.) and should only convey metric tons of avoided GHG emissions to the purchaser. To date, offsets have not conveyed any other attributes about the project generating the offset or about the electricity—including a "renewable energy use" claim. While offset projects through CDM are designed to also provide a variety of social and sustainable development benefits, most offset standard methodologies do not quantify these other characteristics or benefits of the project, or transfer or convey them with the offset credit. Those social benefits are designed to "stay" within the community, even as the avoided carbon is sold globally. Users should not infer from the offset any unquantified, unverified, or unspecified other claims about the project.

Coexistence of offsets and scope 2 accounting. Unless otherwise adjusted by local rules, renewable energy generation facilities producing and selling offsets will inherently still provide energy attribute information—directly and indirectly—to other entities in the local energy supply system, including energy consumers reporting scope 2 emissions. For instance, the energy output from generation facilities producing offsets would still be subject to energy supply contracts between generators and suppliers, and still support the local grid's operation. This means that the zero emission rate from the generation facility will likely be reflected in several emission factors:

- Grid average emission factors (location-based)
- Supplier-specific emission factors (market-based)
- Any PPAs between the generator and consumer of the energy (market-based)

The contractual information such as PPAs and supplier-specific emission factors may meet the Scope 2 Quality Criteria and qualify as conveyers of energy generation emission rates under the market-based method. This can provide accurate scope 2 accounting independent of the fact that certain facilities associated with those contracts will have also produced offsets (reflecting the impact of that generation on the rest of the grid). Therefore, the zero emission rate from the project will likely be reflected in the local grid's data for both the location-based and market-based method for scope 2, as illustrated in Figure 8.1. However, in most industrialized energy markets, a given MWh of renewable energy generation can either produce energy attribute certificates or an offset credit (if certain criteria such as additionality are met), but could not produce both.

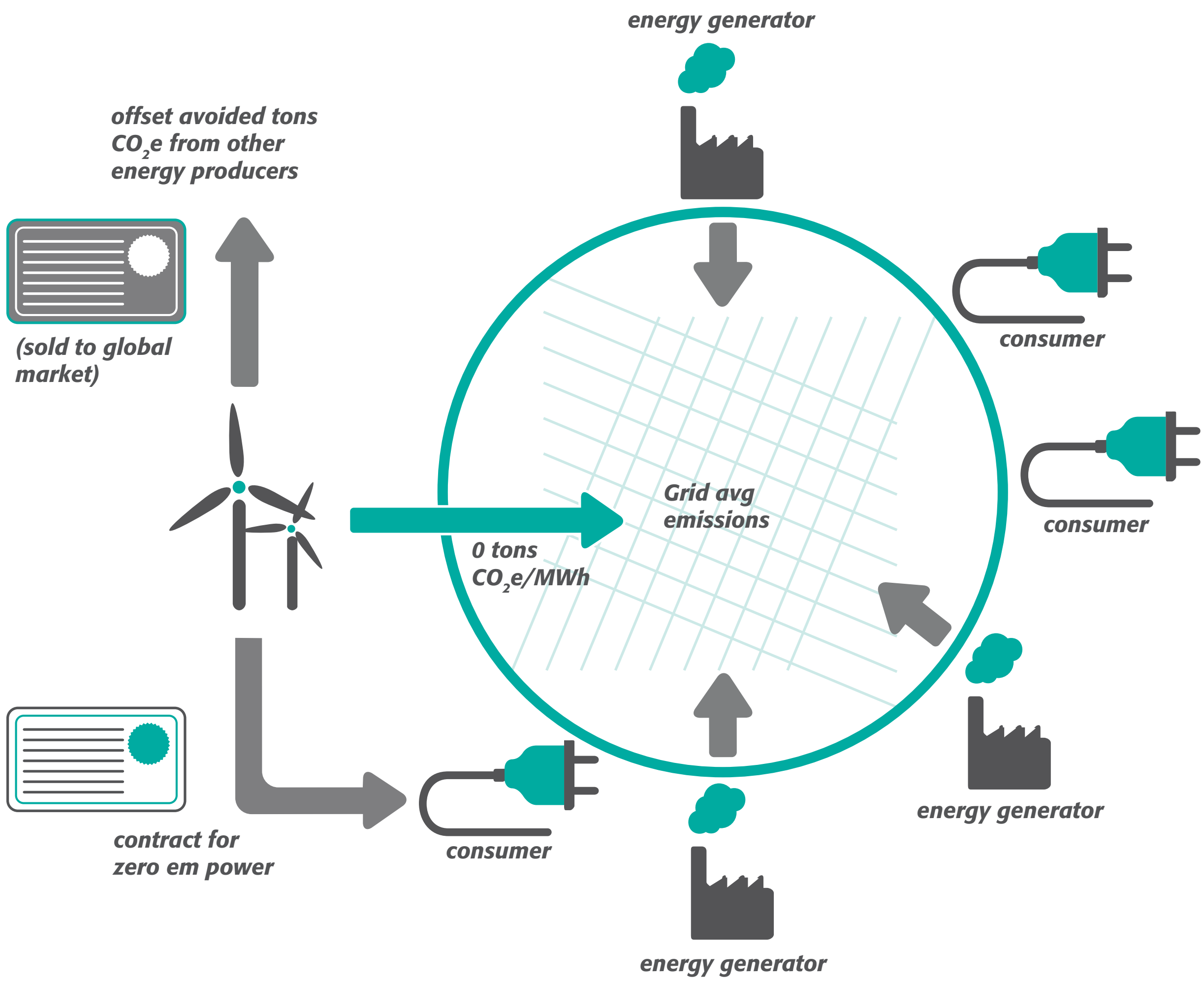
Reporting options: Companies should disclose whether their contractual instrument used in a market-based method (such as a supplier-specific emission rate or PPA) is generated from, or includes, the energy output of a facility that also produces GHG offsets. This may be most relevant in non-Annex I countries generating CDM offsets.

In turn, following the *Corporate Standard,* companies purchasing and claiming offsets should document these purchases outside of the scopes, ensuring that the offset meets offset quality criteria.

Caveats: The coexistence of offsets does not inherently prevent electricity suppliers or companies from reflecting the zero emissions attributes in their scope 2 reported totals. However, local or international regulation may preclude accounting for these emissions, either by:

- Adjusting a grid-average emissions factor to "add back in" the sold offset to the total emissions produced in the region. This increases the GHG intensity of the grid-average emission rate, effectively reflecting the business-as-usual (BAU) scenario of the offset.

Figure 8.1 Offsets and energy attribute certificates on a grid



- Requiring provisions in energy purchase contracts that the attributes associated with the energy generation, while not contained in the offset, should be retired from usage so that no consumer can use contractual instruments to make market-based scope 2 claims.

Historically, voluntary consumer green power purchasing programs have not been implemented in emerging economies generating offsets. This may change over time as local consumers demand low-carbon energy options from their suppliers. (Generally, offsets from the power sector are not possible where the emission caps or other significant low-carbon policies impact the sector.) Where voluntary green power consumer programs coexist with offset issuance, the offset additionality criteria requires that the offset be the decisive reason a project was developed.

Endnotes

1. See Kollmuss and Lazarus (2010).
2. It may appear that the GHG emissions benefit of the offset is "double counted" with any scope 2 allocation procedures for the project's grid, but the differences in methodology and the boundaries for evaluating reductions minimize this possibility.

9 Setting Reduction Targets and Tracking Emissions Over Time

This chapter provides guidance on setting GHG reduction targets for both methods' reported totals, tracking emissions over time, and how other energy goals can be set as part of a holistic approach to energy.

9.1 Setting a base year

A meaningful and consistent comparison of emissions over a GHG reduction goal period requires that companies establish a base year against which to track performance. When companies set a target relative to a base year, companies should specify their reasons for choosing that particular year. Companies reporting according to the market-based method should choose a year in which both market-based data and location-based data are available. Companies that have already set a base year for scope 2 **shall** specify which method was used to calculate it, in order to allow for clearer comparison over time.

For companies calculating a GHG inventory for the first time, the *Corporate Standard* guidance on choosing a base year applies (see Chapter 5 of the *Corporate Standard*).

Once a base year is selected, a reporting entity **shall** set a base-year recalculation policy and clearly articulate the basis and context for any recalculations. Whether base-year emissions are recalculated depends on the significance of the changes. A significance threshold is a qualitative and/or quantitative criterion used to define any significant change to the data, inventory boundaries, methods, or any other relevant factors.

9.2 Recalculating base-year emissions

The *Corporate Standard* notes that recalculation may be necessary when changes to base-year emissions would exceed the company's established significance threshold. This may occur when a company restructures its operations (acquisition/divestments/mergers), discovers calculation errors, or identifies changes in calculation methodology or improvements in data accuracy over time. This guidance's new requirement to report scope 2 according to two different methodologies—location-based and market-based—constitutes a change that could trigger base-year recalculation.

Companies should ensure that the base-year inventory includes both a location-based and market-based scope 2 total, if applicable and feasible. This ensures "like with like" comparison over time.

- If the scope 2 base year chosen was calculated only according to the location-based method, the reporting entity should also recalculate a market-based total if contractual information or residual mix totals are available for the base year. If not, companies should state that the location-based result has been used as a proxy since a market-based result cannot be calculated.
- If the scope 2 base year chosen was calculated only according to the market-based method, companies should ensure that the contractual instruments used in the base year meet the Scope 2 Quality Criteria. If not, this should be disclosed and a location-based total stated in place of the market-based method total. In addition, companies should calculate a location-based method total in the base year using emission factors appropriate for that year.

9.3 Setting GHG targets

A key component of effective GHG management is setting a GHG target. Companies are not required to set a scope 2 reduction target, but should consider setting a target in the context of their business goals, the decision-making value for each method's results and how to drive change through supply choices. As noted, reductions in reported scope 2 emissions can occur due to a change in emission factor unrelated to specific corporate action—for example, a reduced grid average emission factor, or reduced residual mix emission factor.

If setting a target, companies shall specify which method is used in the goal calculation and progress tracking, including the method used for the base-year calculation. Where certificates or contractual instruments convey legally enforceable claims, companies setting goals should use the market-based method total for goals. Two targets, one for each method's results, can help prioritize new low-carbon energy projects that will reduce both totals' emissions over time (if contractual instruments are retained from the project).

Several types of targets are possible and require consideration of:

- **Target type.** Whether to set an absolute or intensity target
- **Target completion date.** The duration of the target (e.g., short term or long term target and base year and goal year)
- **Target level.** The numerical value of the reduction target, framed as a change in emissions or absolute level of emissions to be achieved.

Companies seeking to drive change in the overall grid supply in a short period of time should consult the range of procurement options described in Chapter 11.

9.4 Energy targets

Some companies have energy use, procurement, or production targets in addition to GHG reduction targets. Energy targets can be useful in maintaining a focus on efficiency and isolating the role of consumption as compared with the changes in emissions resulting from supply changes.

- **Energy intensity goals**. Reducing the amount of energy per square foot of office/building space, or per product or output, can help maintain a focus on efficiency practices and set the overall energy performance of operations.
- **Renewable energy procurement goals**. Some companies have set the goal to be powered or supplied by 100 percent renewable energy. The framework for scope 2 emissions accounting, with a separation by method, can be applied here as well. This would require companies to clarify which method their renewable energy goal is based on: a location-based assessment of production on the grid, or a company's contractual procurement using instruments that convey a claim to consumers regarding the resource identity and use.

9.4.1 Achieving 100 percent renewable energy when supplier quotas apply

For utilities under a supplier quota requirement (such as an RPS in the U.S.), structuring a green power product that covers 100 percent of a customer's electricity load may combine voluntary and compliance instruments up to the level of the quota, provided those compliance instruments convey energy use claims. For example, if a utility is required to procure and deliver renewables for 20 percent of its total retail load, then voluntary contractual instruments would be required to account for the remaining 80 percent of the delivered energy.

- **Renewable energy production goals**. Companies that own/operate energy generation facilities providing on-site power to their operations may wish to set goals around the amount of energy produced from these facilities (for example, to produce 100 percent renewable energy in X facilities). Emissions from these facilities would be reported in scope 1, but the production and its attributes may or may not be tracked in scope 2 depending on energy sold to the grid, or certificate sales from the energy which would preclude any consumption claims on the generation. Publicly communicated goals about on-site energy production should indicate the distinction between this metric and energy consumption reflected in scope 2.

10 Key Concepts and Background in Energy Attribute Certificates and Claims

This chapter provides an overview of the key concepts, theories, and uses of energy attribute tracking and claims, which underpins the market-based method for scope 2 accounting. It explains the interactions between voluntary consumer programs and policies directly or indirectly supporting low-carbon energy.

10.1 Introduction to energy attribute tracking

Consumers of grid-supplied electricity cannot link, force, or otherwise direct a specified unit of electricity from its point of generation to its point of final use. Consumers are reliant on grid operators to make decisions about dispatch throughout the day. In addition, grid-supplied electricity consumers cannot directly or physically distinguish the energy generation facilities that are supplying their consumption at any given point; once energy is generated and distributed in a grid system, it becomes physically indistinguishable. In these types of systems, where attributes are not clear at the point of usage, allocation of energy attribute information is necessary to facilitate product-specific consumer claims. Suppliers and consumers increasingly have demanded information about the sources producing their energy, and "attributes" about that production—that is, characteristics such as the GHG emissions, local air pollutants, nuclear waste quantities, etc.

10.1.1 Contractual instruments

Contracts and other contractual instruments have been used historically to transact energy and convey information about energy generation attributes throughout an energy supply system, separately from the underlying energy flows. Depending on the contractual instrument, suppliers or their customers may be able to make claims about the source and attributes of energy they have purchased. These contractual instruments are necessary in order to allocate attributes of production (including GHG emissions) to individual users. By contrast, the "location-based method" indirectly allocates these emissions based on statistical averages, which do not convey attributes or legally enforceable claims about those attributes, or support broader programs for consumer choice.

A range of contractual instruments may be used to convey these attributes directly or indirectly to consumers, including energy attribute certificates, direct contracts such as PPAs, and supplier-specific emission rates. Of all of these, energy attribute certificates underlie most transactions and

attribute claims. They can be used alone or can be bundled with PPAs, contracts, and supplier labels. Once attributes are codified and conveyed in a certificate, the underlying energy generation technically becomes “null power,” or without attribute identity. Users of the null power electricity cannot claim to be buying or using renewable energy in the absence of owning the certificate. Instead, null power should be assigned residual mix emissions for the purpose of delivery and/or use claims in the market-based method.

10.2 Defining energy attribute certificates

Energy attribute certificates are a category of contractual instrument that represents certain information (or attributes) about the energy generated, but does not represent the energy itself (see Figure 10.1). This category includes instruments which may go by several different names, including certificates, tags, credits, or generator declarations. For the purpose of this guidance, the term “energy attribute certificates” or just “certificates” will be used as the general term for this category of instruments. Historically, most certificates for policies or consumer programs have been generated from renewable energy resources, driven by demand for these resources in particular, but depending on their intended purpose or usage certificates can be generated from any or all generation technology types. For example, all-generation certificate tracking exists in the northeast U.S.

10.2.1 Defining GHG attributes and claims

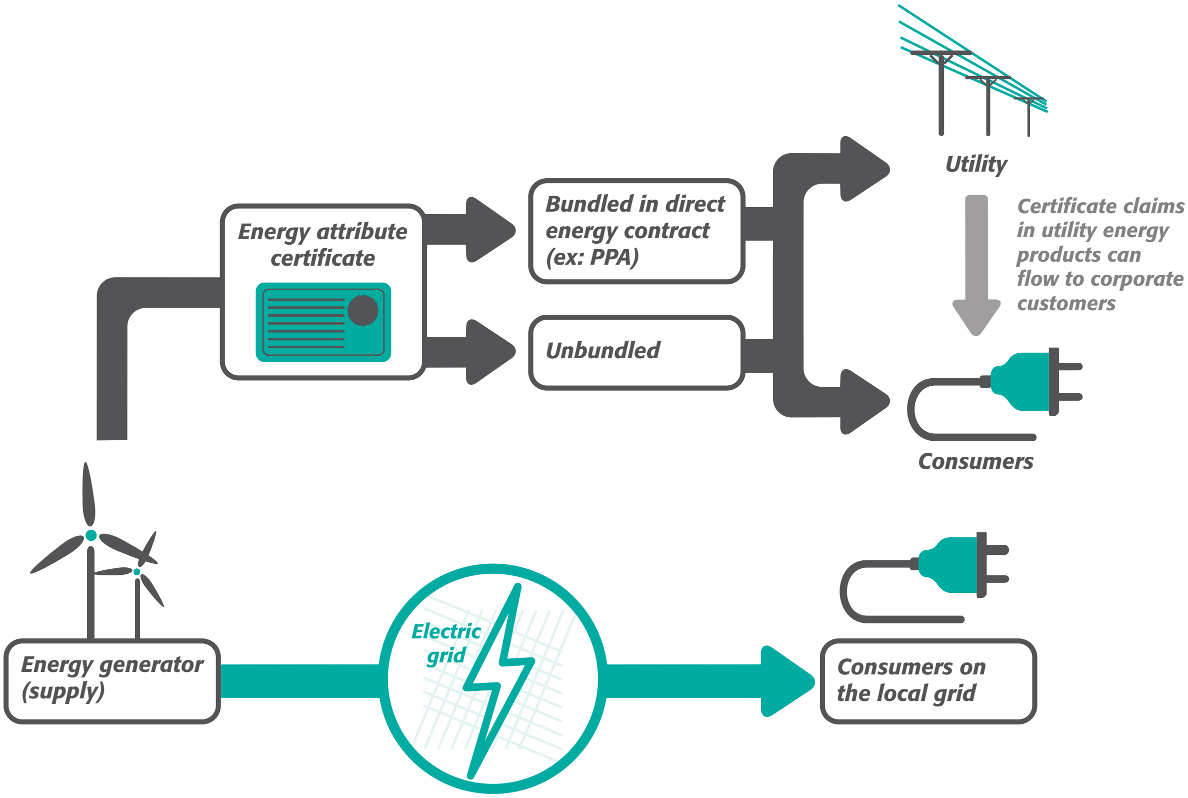
All energy generation has a GHG emission rate attribute, even if that attribute is “zero emissions/ MWh” at the point of generation.

Attribute aggregation. It is theoretically possible to disaggregate different energy generation attributes across multiple certificates, where each certificate conveys different information and related claims. For example, one certificate could convey that the energy comes from a “renewable” resource, while another conveys a claim about the GHG emission rate associated with the production, or claims about the emissions of other pollutants like NO_x and SO_x (see Box 10.1). But attribute disaggregation has generally not occurred in the programs surveyed in this guidance. In the U.S., most states define RECs for RPS purposes as encompassing “all environmental attributes,” including the attribute of the fuel type/ generation technology as well as GHG emission rate, and U.S. tracking systems do not support separating individual attributes. This “all attributes” approach effectively prevents the same MWh being used to create multiple consumer claims from renewable energy projects in the U.S.

Where no attributes for consumer claims are conveyed. Some certificates designed for regulatory uses such as supplier quotas do not convey any generation attributes for consumer claims. These are not intended to support consumer claims; instead, they serve only as documentation that a specific quantity of energy has been generated pursuant to the policy’s requirements. In this scenario, other certificates could be generated that do convey attributes about the energy generation to characterize consumption.

Claims about attributes. Ensuring the validity of consumer claims associated with certificates requires many of the same safeguards as other environmental commodities: accuracy, exclusivity, and enforceability. These form the basis of the Scope 2 Quality Criteria for

Figure 10.1 Energy attribute certificate pathways



claims regarding GHG emissions in the scope 2 market-based method (see Chapter 7). In many cases, there are independent standards and certifications available to enforce these safeguards. A certificate purchaser can make a claim about attributes when applied to a quantity of actual electricity consumption.

10.2.2 Steps in certificate issuance, tracking, and claiming

Most certificates follow the pathway from issuance to claims as follows:

1. **Certificates produced.**

   Certificates are generally produced for one unit of generation (a MWh).

   Energy generators generally produce a certificate directly through registering an account in a registry or other tracking system. Generators report production data (MWh) to the tracking system as well as data about energy attributes, which should meet whatever measurement and verification protocols are required by that system . In the U.S. a generator actually creates the REC, and it can be conveyed by bilateral contracts. If the generation data is reported to a tracking system, the tracking will formally issue a certificate. Each certificate has a unique tracking number. Entities that wish to participate in the market and trade and own certificates must also register with a tracking system and open one or more accounts. Trading can occur, but each certificate can reside in only one account at a time to avoid double counting.

   In some markets, a regulator or independent third party can serve as an "issuing body" that documents the creation of a certificate. See Box 10.1 on energy attribute tracking systems, and Figure 10.2 for an illustration of the different tracking systems in North America. See Box 10.2 for a discussion of the separation of roles in these systems to support independent issuance.

Box 10.1 Energy attribute tracking systems

A certificate tracking system or certificate registry is a tool to help execute energy attribute certificate issuance, retirement, and claims. It issues a uniquely numbered certificate for each unit of electricity (usually one MWh) generated by a generation facility registered in the system, tracks the ownership of certificates as they are traded among account holders in the tracking system, and records certificates that are redeemed or retired in order for users to make claims based on the certificate's attributes. Because each MWh has a unique identification number and can only be in one owner's account at any time, this reduces ownership disputes and the potential for double counting. Tracking systems are designed to ensure that no other entity is issuing certificates for the same MWh, and that all the attributes of that unit of generation remain with the certificate and are not sold as a separate instrument or right of ownership. Certificates may be imported to or exported from these tracking systems, and may also be retired within the tracking system on behalf of a purchaser whose corporate offices and facilities are located outside the footprint of the tracking system. They do not operate as exchanges or trading platforms for the certificates they issue, track, and redeem or retire.

2. **Third-party certification and labeling.** In some markets, a third party may also certify certificates based on an established standard that specifies what energy can produce certificates, an audit procedure to verify retail transactions, and other consumer protection features. Some examples of voluntary certification programs include Green-e (North America) EcoLogo (Canada), and GreenPower accreditation (Australia). Electricity labels such as EKOenergy serve a similar function by specifying a set of criteria that can be applied to determine which certificates can receive the label.

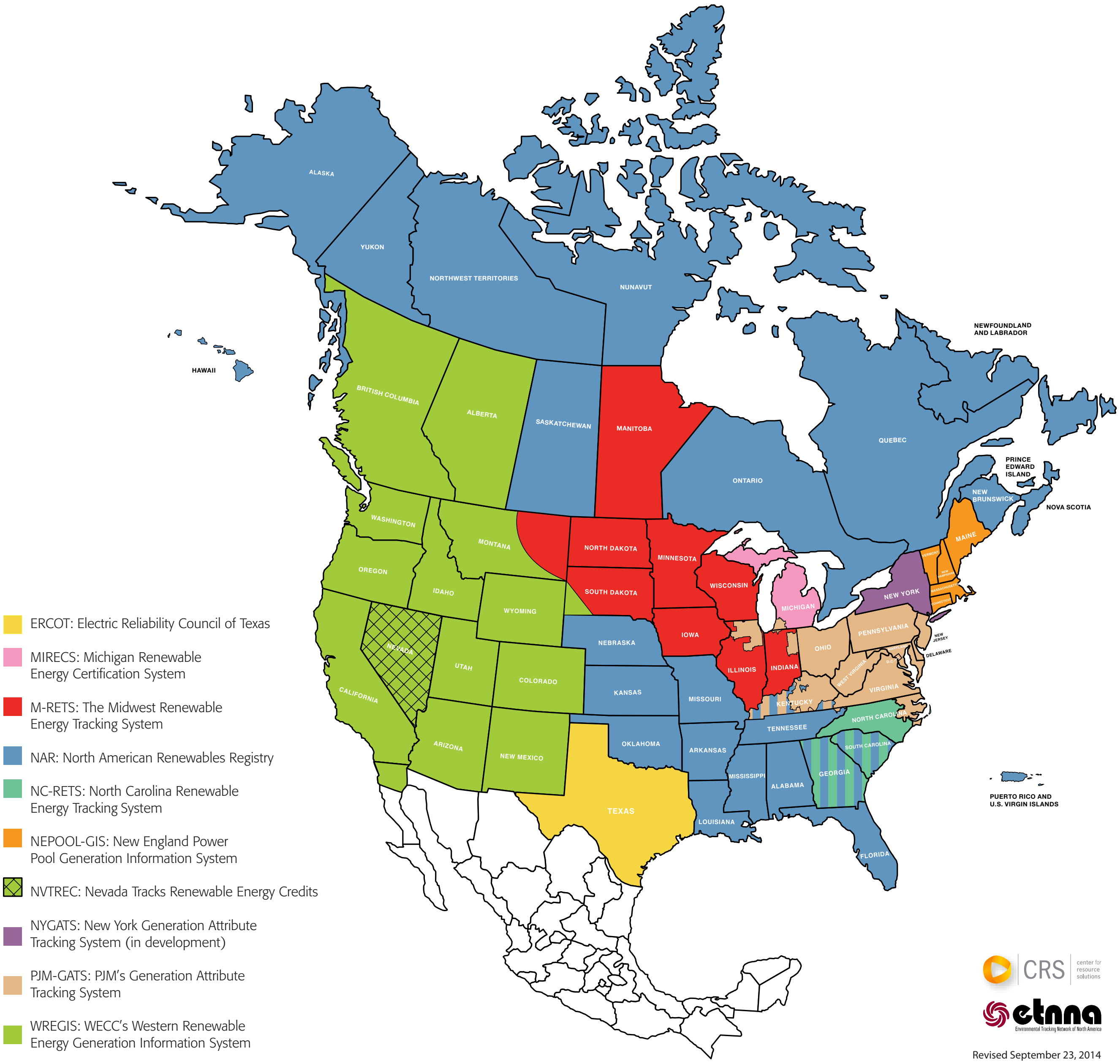
3. **Purchase and retirement by suppliers or consumers.** Certificates can be combined (or "bundled") with a contract for energy, or may be sold separately.[1] Certificates may be traded several times between the initial buyer and suppliers, or through open exchanges. For most certificates, the final purchaser or claimant will be an energy supplier or utility, or an end-consumer. If a certificate serves a regulatory purpose, the claimant (usually an electricity supplier) will submit and retire the certificate to regulatory authorities to substantiate delivery of specified electricity to its customers as required by law. If the certificate serves a voluntary consumer claims purpose, the claimant will retire the certificate in order to facilitate a claim on behalf of its consumers (if a supplier) or itself (if an energy consumer).

Box 10.2 Best practices to ensure independent issuance

In order to ensure the fair competition of issuance, redemption, and use of contractual instruments, most markets have established a clear distinction between the management and ownership of the tracking system and the market players and consumers using the instruments. The ability to transfer contractual instruments and redeem the contained attributes should be possible without direct intervention from the certificate issuer or registry owner. The production facility owner is typically in direct control of the creation of the contractual instruments and will be the single owners of the created instruments until they decide to release their ownership to another third party. The owners of the tracking system or contractual instrument registry **should not** also be active in the market for the same contractual instruments. The documentation of the tracking system should be publically available and open to public consultation.

Figure 10.2 **Energy attribute tracking systems in North America**

Renewable Energy Certificate Tracking Systems in North America



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10.3 Certificate uses

Certificates generally serve four main purposes, including:

- Supplier disclosure
- Supplier quotas, for the delivery or sales of specific energy sources
- Levy exemption
- Voluntary consumer programs

Each program or policy will establish their own eligibility criteria. These criteria specify certain energy generation facility characteristics, such as type of technologies, facility ages, or facility locations. Certificates must come from facilities meeting these criteria in order to be eligible for use in that program. In addition, individual country markets or policy-making bodies (referred to in this guidance as "jurisdictions") may accomplish these different functions using a single certificate system or a multi-certificate system.

- **Single certificate systems**
  In a single certificate system, only one certificate can be issued for each MWh generated and contain attributes associated with that unit of energy generation. This means that a certificate could fulfill multiple purposes—for example, it could be the evidence of supply pursuant to a supplier energy source quota, or be part of standard supplier products as well as voluntary programs or tariff offerings. An example of a single certificate system is the U.S. REC, where a REC may be used for supplier quotas where present (requirements or "eligibility" varies by state), voluntary consumer programs, or in supplier disclosure where supplier quota or voluntary consumer programs or labels are included.
- **Multi-certificate systems**
  A multi-certificate system can have multiple certificates issued for the same unit of energy, each conveying different attributes or claims for each function they serve (see an example of this for the U.K. in Figure 10.3). However, program policies and rules still determine what certificates may be eligible for the program. For the purposes of market-based scope 2 accounting, consumers in multi-certificate systems **shall** identify which certificate, if any, conveys GHG emission attributes to end users, and ensure that only one certificate, or jurisdictionally defined combination of certificates, does so (following the Scope 2 Quality Criteria in Chapter 7). A system could not, however, have multiple certificates each conveying the same consumer claims attributes; this would constitute double counting.

10.4 Supplier disclosure

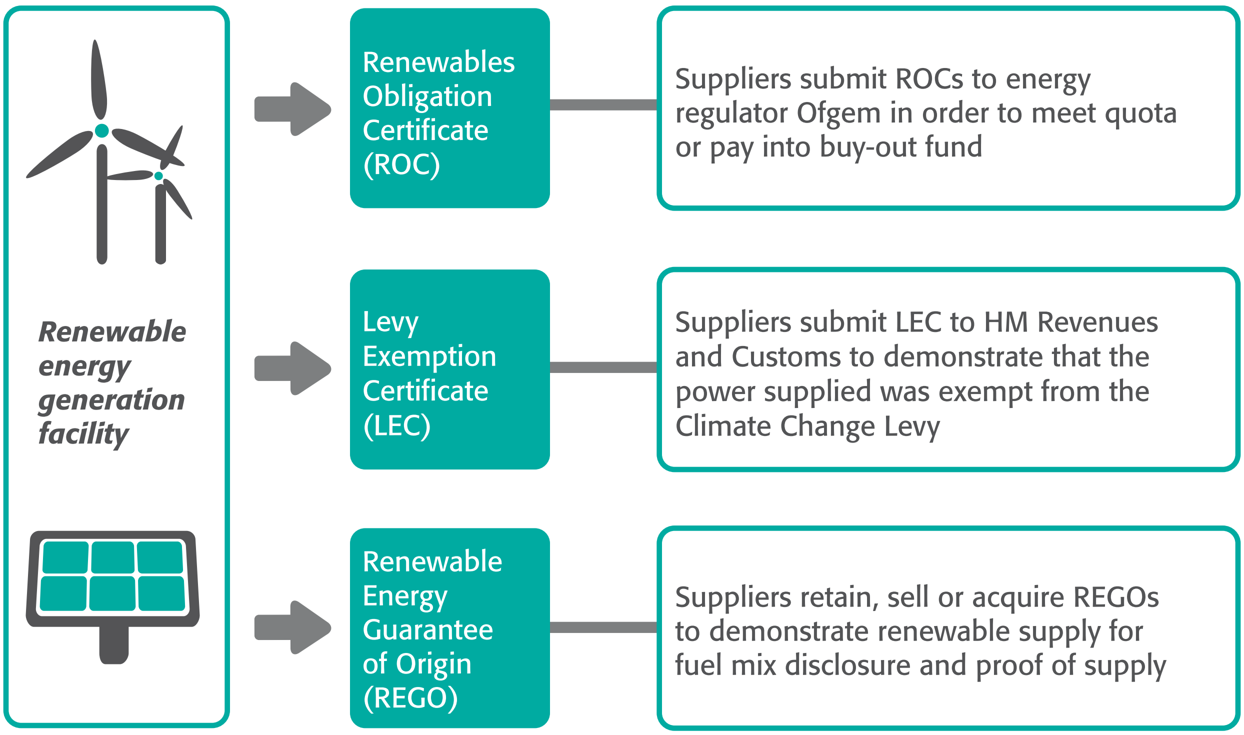
Energy suppliers may be required to disclose to consumers the fuel mix and related environmental attributes associated with delivered supply. Certificates have been used to track energy from production to the supplier, in order for a supplier to contractually demonstrate the source of the energy that is delivered to customers. Suppliers may disclose an emission rate associated with voluntary programs such as renewable or low-carbon energy products (often termed a green pricing program, green power tariff, or green power label), or other differentiated product offerings. In some countries, all consumers are required to make a choice about their electricity product, and information about the electricity product—including its resource mix, CO_2 emissions, and other environmental effects such as radioactive waste—is available on electricity bills.

Some supplier disclosure requirements may not explicitly require the use of certificates. For instance, in Japan power suppliers are obligated to report their supply mix and its associated emission factors to the Japanese government, and the government evaluates and publishes these emission factors.

Example of supplier disclosure

EU electricity market liberalization enabled consumers for the first time to choose their electricity supplier. This prompted the need for more standardized supplier disclosure about their energy supply and its attributes, allowing consumers to compare suppliers on metrics beyond just cost. The EU instituted requirements for all electricity suppliers to disclose their fuel mix to customers, along with the CO_2 quantity and radioactive waste. The Guarantee of Origin certificate has been used as the basis for suppliers to calculate and disclose the energy source and attributes associated with supply. It is also used as the basis for voluntary consumer labels.

Figure 10.3 UK: Example of multiple certificates for distinct purposes



10.5 Supplier quotas, for the delivery or sales of specific energy sources

To help incentivize growth in renewable energy resources, some nations or subnational entities have required electricity suppliers to source an increasing portion of their load from specified or "eligible" renewable energy resources by a specific date. Eligibility criteria may specify the age or location of generation facilities, specific technologies, etc. These supplier energy source quotas may require suppliers to obtain and submit energy attribute certificates to cover the specified portion of their overall supply. Suppliers not in compliance often pay a fine or fee. Some of these supplier energy source quota programs are called "support schemes" as they financially support generators who can sell compliance certificates to suppliers. But as a category, supplier energy source quota policies should be distinguished from other types of support policies such as tax credits or feed-in tariffs associated with production. The latter are direct payments to generators as opposed to revenue received by a generator from the sales of a certificate, and feed-in tariffs do not need to be tracked through certificates. The latter are thus not tied to quotas at a supplier level (for example, there is no "minimum" amount that must be produced). In addition, there is no delivery requirement and thus no need to track generation with certificates.

10.5.1 Certificate multipliers

Some jurisdictional compliance programs provide additional incentive for specific energy sources by providing a "credit multiplier" to a certificate when it is redeemed for compliance with program requirements. The multiplier is applied only when the certificate is redeemed for supplier quota compliance. For instance, a credit multiplier of 1.5 means that when a certificate is retired and claimed for compliance, it is counted toward compliance as if it were 1.5 certificates. Suppliers using certificates for disclosure should use the attributes stated in the certificate (per MWh) and not its multiplication for policy compliance.

Examples of supplier quotas

In the United States, states can set renewable energy portfolio (RPS) standards obligating suppliers to source a minimum share of renewable energy certificates (RECs) from qualifying sources that the policy identifies. For example, California requires that 20 percent of retail sales be supplied with renewable energy by 2013, 25 percent by 2016, and 33 percent by 2020. Policies identify what types of generation can achieve compliance. Policies can also identify a portion of the overall goal that must be met with specific resources (called a "carve out").

In the EU, Directive 2009/28 requires that member states meet renewable consumption targets by 2020 (called national targets). According to current EU law, GOs alone cannot be used as compliance instruments for suppliers to demonstrate fulfillment of national targets. Instead, other instruments such as Green Electricity Certificates in Belgium, Certificati Verdi in Italy, the Elcertifikat in Norway-Sweden, or Renewable Obligation Certificates (ROCs) in the UK, may be used by suppliers.

10.6 Tracking tax/levy exemptions

Tax credits or reductions for producers of specified energy sources (generally renewable or low-carbon) can improve the cost competitiveness of new projects that would otherwise face financial barriers. In addition, certain energy consumers may also be subject to taxes on their energy use relating to environmental externalities of conventional energy production (e.g., a CO_2 tax). Purchasers of renewable or other specified energy may be exempted from these taxes if they can prove their consumption through certificates.

Example of tracking tax/levy exemptions

In the UK, non-residential or "non-domestic" users—primarily large commercial or industrial energy users—are taxed for their energy use. But renewable electricity and electricity produced from coal mine methane are exempt from the tax. Renewable energy generation facilities are issued Levy Exemption Certificates (LECs), which suppliers must acquire on behalf of their non-domestic customers to avoid the tax (with LECs serving as evidence submitted to HM Revenue & Customs).

10.7 Voluntary consumer programs

Energy attribute certificates have been used as a means to promote voluntary consumer demand for the attributes of renewable or low-carbon energy and to support the consumer claims around those choices. These voluntary programs may be offered by an electricity supplier as a special tariff or product in addition to their standard offering; or, consumers in some jurisdictions may have competitive choice in their supplier and select a supplier offering exclusively specified energy products, such as an "all renewable" label. Consumers in all jurisdictions may also have the ability to directly purchase certificates (outside of their electricity delivery arrangement with local suppliers) to enable a claim. Voluntary consumer programs generally seek to both enhance consumer product choices and voluntarily leverage demand to increase the share of renewables on the grid over time.

Examples of voluntary consumer programs

- In the U.S., voluntary RECs can be obtained directly by a consumer ("unbundled" from energy purchases), or "bundled" through a supplier program or in an electricity contract such as a PPA.
- In the EU, GOs (rooted in disclosure laws) have also been used to support voluntary renewable energy purchases and claims.
- In Australia, the voluntary GreenPower program uses RECs in its accreditation label, which is supported and managed by state governments in Australia.
- Globally, The International REC Standard creates standardized attribute tracking certificates for the purposes of voluntary corporate disclosure. The legislative basis for the certificate issuance may be different in each country where the standard is active.

10.8 How jurisdictional policies affect the role and impact of voluntary programs

In most jurisdictions, voluntary consumer purchasing programs (and therefore market-based claims) will reflect attributes from energy generation that interacts with local or federal policies. This is consistent with the fact that in most markets, all energy—be it fossil, renewable, or low-carbon—is regulated to some extent and benefits from direct and indirect financial support. Renewable or low-carbon energy production and consumption in particular may benefit directly or indirectly through subsidies, cap-and-trade programs, supplier energy source quotas, etc.

However, the relationship between voluntary consumer purchasing programs and regulatory policy may be more sensitive or subject to stakeholder scrutiny. For instance, stakeholders may ask whether the purchased energy reflected in the voluntary certificate has "received a subsidy," or "helps lower the emissions cap on the power sector," or represents energy purchased in surplus of the electricity supplier's quota. These objectives can reflect a desire for voluntary consumer programs to ensure equal consumer benefit sharing—that is, that subsidized energy remains a publicly claimed benefit rather than one available for individual consumer claims. They can also reflect a desire for consumer action to have an impact on the market for low-carbon energy that goes beyond the incentives and trends dictated by policy.

Most of the relationships between voluntary programs and regulatory incentives or policies will be determined at the jurisdictional policy-making level, since regulators typically determine what types of certificates are issued for what policy purposes. The decision to use a single-instrument system may automatically address some of these voluntary policy interactions by ensuring the attributes of each unit of energy are only used for one purpose. The single-instrument scenario in the U.S. is sometimes termed "regulatory surplus,"[2] sincethe renewable energy claimed by voluntary purchasers cannot also be counted toward a state RPS program that delivers renewable energy to customers. Jurisdictions may also choose to:

- **Exclude voluntary claims from policy-supported energy generation.** This means that certificates used for voluntary claims may not also be used for supplier quota compliance targets, for claiming a direct subsidy, or for producing an offset.
- **Require pairing of the voluntary certificate with a regulatory certificate.** This means requiring multiple certificates to be "paired" together in order to enable voluntary consumer claims from certain types of power, even if a single instrument alone may technically convey the attributes necessary for claims. This could entail suppliers being required to retire both the certificate they use for disclosure along with the certificate used for levy exemption. Voluntary allowance set-aside programs in emissions-capped power sectors also serve as a type of "instrument pairing" to fulfill goals beyond scope 2 accounting.

Companies should check with their electricity supplier or relevant policy-making bodies to ensure that voluntary certificates are claimed, paired, or retired in compliance with jurisdictional requirements. Companies should report these relationships separately (see Chapter 8).

Endnotes

1. For example, the U.S. Federal Trade Commission (FTC) has not recognized a distinction with respect to marketing or consumer claims between purchasing a bundled product or unbundled certificates and electricity separately.
2. This has also been termed "regulatory additionality," though this Guidance distinguishes between the specific use of the term "additionality" in offset accounting and the diverse types of objectives and criteria that can be applied to energy attribute certificates.

11

How Companies Can Drive Electricity Supply Changes with the Market-Based Method

This chapter describes how market-based consumer actions and claims can drive change in electricity generation supply over time, and clarifies why this guidance does not establish requirements on policy relationships or "market impact" criteria. It elaborates how companies can use their procurement power to substantively contribute to new low-carbon energy supply.

11.1 Energy attribute supply and demand

The four certificate uses described in Chapter 10, though distinct, are all generally designed to support growth of low-carbon energy by increasing demand for specific attributes. As demand grows, it will push up the price of these attributes, which in turn can stimulate supply. This theory underlies the basis of market-based accounting in scope 2, as it reflects an allocation of consumer preferences (demand) for the GHG attributes from a given supply of attributes available for those claims. Because these energy attributes are finite, a voluntary energy purchase and attribute claim prevents others from making the same claim on those MWh and requires other consumers to source from the remaining unclaimed (and typically more GHG-intensive) energy attributes. In short, if demand for low-carbon energy, which on a shared grid can only be expressed using certificates and contracts, begins to approach existing supply, the pressure or incentive to build additional supply grows, with certificates also serving as an additional revenue stream to help signal that demand. This is the same theory that underlies all other markets and is also the basis of scope 3 accounting: all individual purchases contribute to overall demand for a product or type of product, and the more purchases are made, the more this demand will drive changes in production.

The market-based method for scope 2 accounting represents an internationally applicable framework allowing suppliers and consumers to express and aggregate demand for specific types of generation. It treats market-based accounting as an allocation procedure, with the understanding that the effect of the market on grid makeup will depend on the level of demand vs. supply of renewable energy, program eligibility, degree of uptake, policy interactions, and other variable factors. It provides several pathways by which corporate procurement can drive new low-carbon energy development.

11.2 Relationship between voluntary program impact and scope 2 accounting

Consumers who voluntarily claim low-carbon attributes in scope 2 may expect their individual purchase or program participation to result in new generation that lowers system-wide GHG emissions. However, like other markets and products, individual voluntary purchases and consumer programs may or may not result in changes in low-carbon supply, depending on supply and demand dynamics. For instance, one paper[1] suggests that the voluntary REC market in the U.S., when evaluated based on the price of RECs as an incentive for project developers, has not itself driven new renewable energy projects.

Another market analysis[2] indicates that the effect of voluntary demand on new renewable energy project development is not based on the price of those RECs so much as it is on the presence of long-term contracts for RECs and energy from projects as yet unbuilt.

Given that voluntary markets for renewable energy aggregate consumer demand in order to affect supply changes, some stakeholders and voluntary programs have incorporated additional specifications or criteria to stimulate growth of low-carbon supply. For example, these criteria could include requiring voluntary consumer claims to be above or in surplus to supplier energy source quotas, or to be independent from the receipt of public funds, or for market-based scope 2 accounting rules to be aligned with offset credit additionality requirements in order to ensure that each voluntary energy purchase claimed in scope 2 represents a unit of "additional" low-carbon generation or emission reductions. This could mean requiring that an individual voluntary purchase and claim, or a voluntary certificate program, be the decisive reason new low-carbon energy projects are built.

Even in the absence of such requirements, the market-based method accurately reflects an allocation of generation attributes among consumers, which is important for reflecting individual actions and purchase decisions as well as for recognizing action to affect demand-side change. In the absence of such requirements, and if there is insufficient demand to drive overall change on the grid, stakeholders may be concerned that the market-based method results only in a reallocation of attributes between those consumers who care about claiming low-carbon energy, and those who are unaware of or uninterested in the opportunity to make these claims.

11.3 The role of "additionality"

This guidance does *not* require that contractual instruments claimed in the market-based method fulfil criteria such as offset "additionality" or prove the overall market impact of individual purchases or supplier programs result in direct and immediate changes in overall supply. This follows the same reasoning applied to purchased products in scope 3 accounting, including that:

- **The market-based method for scope 2 accounting applies to all energy generation in a defined grid**, not just "low-carbon" or renewable energy from projects supported by a specific company's financial support. It concerns the larger allocation process of all energy emissions across all end users. All energy has a direct emissions factor associated with generation, and the use of that emissions factor does not depend on whether the generation facility is existing or new, or why the generation has occurred. This guidance lays out the policy-neutral mechanics of a market-based method for scope 2 accounting, so that regardless of what causes the project to be built, the energy attribute certificate still serves as the instrument conveying claims about the attributes of the underlying energy generation for consumers purchasing that generation.
- **Offset additionality criteria are not fundamental to, or largely compatible with, the underlying rules for market-based scope 2 accounting and allocation.** In GHG accounting, additionality is a term specifically associated with offsets and project-level accounting, which is distinct from corporate GHG accounting. The claim that X metric tons of GHG emissions have been avoided at a global level can only be credible if the offset credit was the "intervention"[3] that made the project happen—and that, without that intervention, that project would not have occurred. Such a claim requires proof of cause-and-effect and is critical to support the integrity of offset credits. However, offsets represent a different claim (avoided GHG emissions

compared to a baseline scenario) than energy generation attributes (X GHG emissions from Y unit of energy generation). Scope 2 reporting is a report of usage and as such is independent of issues associated with additionality.

In short, voluntary programs have been designed in different ways across jurisdictions, and with differing relationships to other policies promoting the growth of low-carbon energy supply. Maximizing the speed and efficacy of voluntary initiatives in driving new low-carbon development is an important, complex, dynamic, and evolving process for program implementers, regulators, and participants. Jurisdictional policy makers, certification programs, supplier labels or tariffs, or consumers are best situated to identify and execute policies in pursuit of these goals. The role of this guidance is to identify the core requirements of accurate market-based accounting (Scope 2 Quality Criteria) that can apply to any jurisdiction's range of contractual instruments, while ensuring sufficient transparency in corporate reports to allow internal and external stakeholders to assess performance and how effectively corporate energy procurement achieves broader company goals—including accelerating the growth of new low-carbon energy in a short period of time.

11.4 How can companies go further?

While not a part of criteria for market-based scope 2 accounting, suppliers and companies can make energy procurement choices that can shift a company's impact from "aggregate" to more directly spurring an increase in new, low-carbon energy generation facilities in a short period of time, consistent with the ambition needed to avoid dangerous climate change. Many of these choices are summarized in box 5.1, highlighting both the policy changes and the individual consumer choices that could, in the case of the U.S., strengthen the impact of voluntary REC products.

In effect, these choices can be framed as a range of stronger and weaker market signals, with the strongest signals being for *new* projects where a company can play a *substantive role* in helping a project go through. Companies can identify procurement choices aligned with new projects (helping to decrease system-wide emissions in a shorter period of time) where the company can bring to bear its financial resources, creditworthiness, scale of consumption, technical knowledge, collaboration, or other approaches in order to help overcome traditional barriers to scaling the development of low-carbon energy. Some of these choices are elaborated below; options for reporting on these efforts are discussed in Chapter 8.

1. **Contract directly with new low-carbon energy projects**
   Long-term power purchase agreements or other contracts for energy procurement often provide the stable revenue structure needed to help attract the additional financing to complete new projects. In order to make a claim on any purchased energy, companies **shall** retain any certificates associated with the energy production because they convey GHG emission rate attributes. In markets without certificates, the contracts themselves may be written to convey these attributes, provided that the energy is not resold to other entities who would make similar claims, and provided that the Scope 2 Quality Criteria are met.
2. **Work with electricity suppliers for new projects**
   Customers of a utility typically have standing in—and thus the ability to influence—proceedings that affect the generation resources owned and/or used by the utility from which they buy power. Consumers can demand low-carbon energy tariffs or purchasing options based on or supporting new low-carbon energy projects that also meet the reporting requirements for scope 2. This model can also allow for collaboration and aggregation of multiple consumers' demand. Customers that individually or collectively represent a large percentage of a utility's load may be most influential in these measures.
3. **Establish "eligibility criteria" for corporate energy procurement, relating to specific energy generation features or policy interactions that align with new low-carbon energy projects.**
   When consumer demand is targeted at a narrower set of criteria, that demand is more likely to meet existing supply and prompt stronger market signals for new facilities meeting specific criteria. For instance, companies can establish their own instrument featuring requirements around criteria such as

technology type, facility age or facility siting, the energy generation's relationship to supplier quotas, etc.

In addition to the certificate policies established by jurisdictional policy makers, other key actors in the energy supply system can also, through their voluntary choices, impact how claimed energy in voluntary programs interacts with policy instruments, depending on the jurisdiction. These key actors include issuing bodies, voluntary certificate standards, or electricity supplier labels or tariffs, or individual companies (see Figure 5.1).

4. Incremental funding or donations

Some voluntary certificate programs or supplier labels or tariffs may structure their product so that a dedicated portion of the revenue from the program is applied as "incremental funding" for new projects identified by the program. This type of fund model, exemplified by GO2,[4] EKOenergy,[5] and TrackmyElectricity[6] in Europe, can help directly contribute to the growth of new low-carbon energy projects. Companies providing this type of donation can document this separately.

Box 11.1 Strengthening the role of RECs as a standalone product

A 2011 publication by the U.S. National Renewable Energy Laboratory (NREL)* noted that there are several ways that purchasers, marketers, and policy makers could "strengthen the role of RECs in both compliance and voluntary markets." Here, strengthening the role of RECs translates, in practice, to an improved ability of purchasers to, in aggregate, create change in global GHG emissions. Some of these options include:

- Encourage long-term contracts for RECs. Long-term contracts can offer the security and certainty that many projects need to obtain financing.
- Host periodic solicitations for medium- to long-term contracts with smaller projects. Smaller projects need a more standardized market, and auctions also increase REC market liquidity and price transparency.
- Adopt a REC price floor. This would ensure a minimum level of support and reliable revenues for new projects.
- Increase renewable energy targets. Increased demand would lead to stronger REC prices.
- Limit eligibility of supply (e.g. by limiting the eligible project age, project location, etc.). Restricting eligible supply also tends to increase REC prices.
- Support greater price transparency. Price transparency increases confidence in current and future REC prices and could lead to a greater recognition for RECs as a potential revenue stream.
- Contribute funds for project development. Primarily an option for the voluntary market, having incremental costs funded up front would reduce the risk for projects that are above-market price.
- Take an equity position in new projects. Direct investment in itself is strong evidence of making new projects happen and has several other advantages. This approach could work for utility-scale projects or for installation of on-site distributed generation.

Source: *Holt, Sumner, and Bird (2011).

Endnotes

1. Gillenwater, Lu, and Fischlein (2014).
2. Holt, Sumner, and Bird (2011).
3. Gillenwater (2012).
4. See GO2 product by ECOHZ at: http://www.ecohz.com/products/products/ecohz-go%C2%B2.
5. See EKOenergy label and criteria at: http://www.ekoenergy.org/our-results/climate-fund/.
6. See Bergen Energi product at: http:// www.trackmyelectricity.com.

Appendices

Appendix A
Accounting for Steam, Heat, and Cooling

The scope 2 accounting concepts, methods, and examples referenced in this guidance are drawn primarily from, and apply primarily to, electricity purchasing and use. However, steam, heat, and cooling energy systems may also use contractual instruments to convey attributes and claims. For instance, companies may have contracts to receive heat or steam from providers that specify the fuel source and emission rate associated with their received energy. In addition, "green heat" certificates generated from biogenic fuel sources may be issued and traded independently from the energy flows and injection into the distribution grid.

Companies **shall** report emissions from the purchase and use of these energy products the same as for electricity: according to a location-based and market-based method, if the contractual instruments used meet the Scope 2 Quality Criteria as appropriate for gas transactions. These may be the same total where direct line transfers of energy are used.

Companies should follow Table 6.1 accounting for scope 2 with and without certificates sales to determine the treatment of direct line energy transfers (e.g., receiving heat/steam/cooling directly from another facility) or energy used from local steam/heat/cooling distribution systems. A location-based emission factor for such systems should characterize the average GHG intensity of the fuels used to generate the heat/steam/cooling, as well as the efficiency of that generation.[1]

Steam, heat, and cooling as a "waste" product.

Emissions from steam, heat, or cooling that is received via direct line as "waste" from an industrial process should still be reported based on the underlying emissions from the original generation process. Some companies may wish to account for these as zero emissions because the steam/heat/cooling would have been vented instantaneously if not used. However, accurate emissions accounting requires the actual emissions associated with the production of this waste to be reported.

Endnotes

1. An emission factor per unit energy for purchased steam or heat is equal to the emission factor per unit energy of the fuel used divided by the thermal efficiency of the generation. An emission factor for purchased cooling that is generated by an electric chiller is equal to the emission factor for the electricity consumed in the chiller divided by the chiller's coefficient of performance (COP).
2. See EPA RFS2 Regulations Final Rule (2010).

Portland General Electric/Flickr


Tambako The Jaguar/Flickr

Appendix B
Accounting for Energy-Related Emissions Throughout the Value Chain

Accounting in a grid-connected electricity value chain

For scope 2 reporting, differences in the regulatory structure of electricity supply chains can impact overall energy procurement options and what emissions are included in a supplier-specific emission factor. They also determine which entity reports which emissions in the energy value chain, as shown below.

The mechanics of electricity distribution on any grid function largely the same way, with the four supply chain phases including: (1) material or fuel extraction and processing; (2) generation; (3) transmission and distribution; and (4) sales to, and consumption by, end users. Different regulatory structures at a regional, national, and subnational level can influence what entities are involved throughout the phases of energy generation, transmission, distribution, and service. For instance:

- In some markets, the utility owns the generation assets, transmission and distribution (also known as T&D) infrastructure, and interfaces with the consumer to deliver energy. These entities would report all generation emissions in scope 1, and no T&D losses would be reported separately since the emissions would be already reported in scope 1.
- In others, power generators may be independent entities from which the utility buys power.
- In fully deregulated or competitive markets, each activity in the supply chain could be conducted by a different company. For instance, a customer may interface with energy retailers or suppliers who only sell electricity but who do not own generation assets or T&D equipment. Because these entities purchase and sell, but do not produce or consume the energy, they do not record either scope 1 or scope 2 emissions from the energy they sell.

Figure B.1 illustrates in which scope each entity in the electricity supply system (depicted in the rows) accounts for the emissions occurring during these different phases of electricity generation, distribution, and use (depicted as phases in the column).

See Appendix A of the *Corporate Standard* for more information on these relationships.

Accounting for energy-related emissions in scope 3

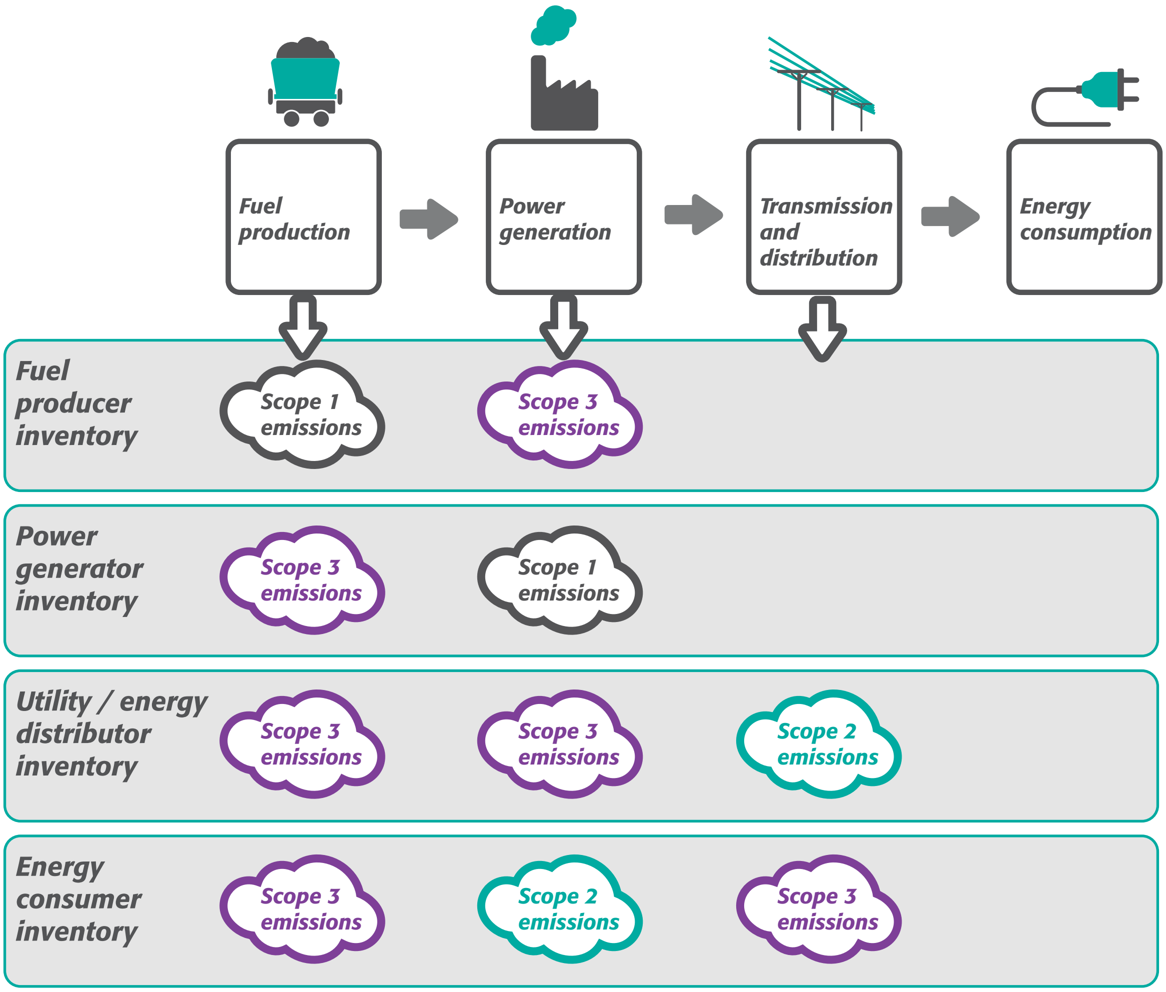
Scope 2 emissions from different value chain partners form the basis of almost all fifteen scope 3 categories. Therefore, companies obtaining energy emissions data from their suppliers to be used in scope 3 calculation should ask which scope 2 method was used to calculate the results. In turn, companies should be transparent about which scope 2 method total they share with others in their value chain.

Category 3: Upstream fuel and energy-related activities

For an energy consumer, category 3 includes upstream emissions from fuel extraction and processing prior to its combustion (known as the cradle-to-gate emissions) as well as the energy consumed (e.g. "lost") during transmission and distribution. Because of T&D losses, the actual amount of electricity generated at a power plant will be greater than the total electricity consumed by customers alone.[1] On-site generation does not incur T&D losses, as there is virtually no "line" in which transmission and energy losses occur.

The energy quantity consumed and reported in scope 2 serves as the basis for determining T&D activity data. One example of how this can be calculated is by applying the grid loss factor (ex: 7 percent grid loss rate for 100MWh consumption would mean 7MWh lost in T&D).Companies may also get information on line losses from the entity that controls the lines. Companies would need to apply an emissions factor to that line loss consumption to determine emissions associated with the loss. Companies should disclose which calculation method they are using to calculate and report T&D losses in scope 3 category 3, but do not need to "dual report" this. For instance, if companies, their suppliers, or other value chain partners have purchased energy attribute

Figure B.1 Accounting for electricity emissions throughout the supply system



certificates to cover the quantity of grid losses, they can report this calculation based on the market-based method procedures in this Guidance. If not, companies should use the location-based method emission factors.

Companies should also disclose which scope 2 results—location-based or market-based—they are using as the basis for calculating upstream fuel extraction and processing emissions. For example, a scope 3 category 3 assessment based on the results of a location-based scope 2 report could reflect the upstream profile of the mix of grid resources (natural gas, coal). A category 3 assessment based on the results of a market-based scope 2 report could reflect the upstream emissions associated with producing renewable energy.

Category 15. Investments.

Any investments in energy generation facilities or other projects not associated with a contractual arrangement reflected in scope 2 can report emissions from these investments in category 15.

For scope 3 calculation procedures, see GHG Protocol *Value Chain (Scope 3) Standard* and *Scope 3 Calculation Guidance.*

Endnotes

1. Companies are not required to account for line losses due to unauthorized connections or energy theft, which make up a significant percent of T&D losses in many jurisdictions.

Abbreviations

CH_4	Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
GHG	Greenhouse Gas
GWP	Global Warming Potential
HFCs	Hydrofluorocarbons
IAS	International Accounting Standard
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
kg	Kilogram
km	Kilometer
kWh	Kilowatt-hour
LCA	Life Cycle Assessment
LFGTE	Landfill-gas-to-energy
MSW	Municipal Solid Waste
MWh	Megawatt-hour
NGO	Non-Governmental Organization
N_2O	Nitrous Oxide
PFCs	Perfluorocarbons
QA	Quality Assurance
QC	Quality Control
SF_6	Sulphur Hexafluoride
t	Metric tons
T&D	Transmission and Distribution
UNFCCC	United Nations Framework Convention on Climate Change
WBCSD	World Business Council for Sustainable Development
WRI	World Resources Institute

Glossary

Activity data	A quantitative measure of a level of activity that results in GHG emissions. Activity data is multiplied by an emissions factor to derive the GHG emissions associated with a process or an operation. Examples of activity data include kilowatt-hours of electricity used, quantity of fuel used, output of a process, hours equipment is operated, distance traveled, and floor area of a building.
Additionality	A criterion often applied to GHG project activities, stipulating that project-based GHG reductions should only be quantified if the project activity "would not have happened anyway"—i.e., that the project activity (or the same technologies or practices that it employs) would not have been implemented in its baseline scenario.
Allocation	The process of assigning responsibility for GHG emissions from a specific generating unit or other system (e.g., vehicle, business unit, corporation) among its various users of the product or service.
Allowance	A commodity issued by an emissions trading program that gives its holder the right to emit a certain quantity of GHG emissions.
Annex 1 countries	Defined in the International Climate Change Convention as those countries taking on emissions reduction obligations: Australia; Austria; Belgium; Belarus; Bulgaria; Canada; Croatia; Czech Republic; Denmark; Estonia; Finland; France; Germany; Greece; Hungary; Iceland; Ireland; Italy; Japan; Latvia; Liechtenstein; Lithuania; Luxembourg; Monaco; Netherlands; New Zealand; Norway; Poland; Portugal; Romania; Russian Federation; Slovakia; Slovenia; Spain; Sweden; Switzerland; Ukraine; United Kingdom; and the United States.
Attribute	Descriptive or performance characteristics of a particular generation resource. For scope 2 GHG accounting, the GHG emission rate attribute of the energy generation is required to be included in a contractual instrument in order to make a claim.
Audit trail	Well-organized and transparent historical records documenting how the GHG inventory was compiled.
Avoided emissions	An assessment of emissions reduced or avoided compared to a reference case or baseline scenario.
Base year emissions	GHG emissions in the base year
Base year emissions recalculation	Recalculation of emissions in the base year to reflect a change in the structure of the company or a change in the accounting methodology used, to ensure data consistency over time.
Baseline scenario	A hypothetical description of what would have most likely occurred in the absence of any considerations about climate change mitigation. For grid-connected project activities, the baseline scenario is presumed to involve generation from the build margin, the operating margin, or a combination of the two.
Baseload	A type of power plant that operates continuously (or nearly continuously) to meet base levels of power demand that can be expected regardless of the time of day or year.

Biofuels	Fuel made from plant material, such as wood, straw, and ethanol from plant matter.
Biogenic CO_2 emissions	CO_2 emissions from the combustion or biodegradation of biomass.
Biogenic gas (biogas)	Methane that is produced from a biomass resource, such as animal waste, agricultural waste, landfill gas, municipal waste, or digester gas.
Biomass	Any material or fuel produced by biological processes of living organisms, including organic non-fossil material of biological origin (e.g., plant material), biofuels (e.g., liquid fuels produced from biomass feedstocks), biogenic gas (e.g., landfill gas), and biogenic waste (e.g., municipal solid waste from biogenic sources).
Build margin (BM)	The incremental new capacity displaced by a project activity. The build margin indicates the alternative type of power plant (or plants) that would have been built to meet demand for new capacity in the baseline scenario.
Bundled	An energy attribute certificate or other instrument that is traded with the underlying energy produced.
Cap-and-trade system	A system that sets an overall emissions limit, allocates emissions allowances to participants, and allows them to trade allowances and emission credits with each other.
Certificate	See energy attribute certificate
Certified Emission Reductions (CERs)	A unit of emission reduction generated by a CDM project. CERs are tradable commodities that can be used by Annex 1 countries to meet their commitments under the Kyoto Protocol.

Clean Development Mechanism(CDM)	A mechanism established by Article 12 of the Kyoto Protocol for project-based emission reduction activities in developing countries. The CDM is designed to meet two main objectives: to address the sustainability needs of the host country and to increase the opportunities available to Annex 1 Parties to meet their GHG reduction commitments. The CDM allows for the creation, acquisition, and transfer of CERs from climate change mitigation projects undertaken in non-Annex 1 countries.
CO_2 equivalent (CO_2e)	The universal unit of measurement to indicate the global warming potential (GWP) of each greenhouse gas, expressed in terms of the GWP of one unit of carbon dioxide. It is used to evaluate releasing (or avoiding releasing) different greenhouse gases against a common basis.
Cogeneration unit/Combined heat and power (CHP)	A facility producing both electricity and steam/heat using the same fuel supply.
Company	The term company is used in this standard as shorthand to refer to the entity developing a GHG inventory, which may include any organization or institution, either public or private, such as businesses, corporations, government agencies, nonprofit organizations, assurers and verifiers, universities, etc.
Consumer	The end consumer or final user of a product.
Contractual instrument	Any type of contract between two parties for the sale and purchase of energy bundled with attributes about the energy generation, or for unbundled attribute claims. Markets differ as to what contractual instruments are commonly available or used by companies to purchase energy or claim specific attributes about it, but they can include energy attribute certificates (RECs, GOs, etc), direct contracts (for both low-carbon, renewable or fossil fuel generation), supplier-specific emission rates, and other default emission factors representing the untracked or unclaimed energy and emissions (termed the residual mix) if a company does not have other contractual information that meet the Scope 2 Quality Criteria.
Control	The ability of a company to direct the policies of another operation. More specifically, it is defined as either operational control (the organization or one of its subsidiaries has the full authority to introduce and implement its operating policies at the operation) or financial control (the organization has the ability to direct the financial and operating policies of the operation with a view to gaining economic benefits from its activities).
Direct emissions	Emissions from sources that are owned or controlled by the reporting company.
Dispatch	The coordination of power plant operations in order to meet the load on a grid. A “dispatchable” power plant is one that can be directly called upon by grid operators to produce power, and whose output can be modulated in response to real-time fluctuations in demand for electricity.
Distributed generation	Decentralized, grid-connected, or off-grid energy facilities located in or near the place where energy is used.
Double counting	Two or more reporting companies claiming the same emissions or reductions in the same scope, or a single company reporting the same emissions in multiple scopes.

Electric utility	An electric power company whose operations may include generation, transmission, and distribution of electricity for sale. Also called electricity or energy supplier.
Eligibility criteria	Features or conditions defined by a policy or program that determine which energy generation facilities can participate in the program or whose certificates will fulfill programmatic requirements.
Emission factor	A factor that converts activity data into GHG emissions data (e.g., kg CO_2e emitted per liter of fuel consumed, kg CO_2e emitted per kilometer traveled, etc.).
Emissions	The release of greenhouse gases into the atmosphere.
Energy	Formally, energy is defined as the amount of work a physical system can do on another. In this Guidance, energy refers to electrical energy generated by power plants and delivered to energy users over a power grid.
Energy attribute certificate	A category of contractual instruments used in the energy sector to convey information about energy generation to other entities involved in the sale, distribution, consumption, or regulation of electricity. This category includes instruments that may go by several different names, including certificates, tags, credits, etc.
Energy generation facility	Any technology or device that generates energy for consumer use, including everything from utility-scale fossil fuel power plants to rooftop solar panels.
Equity investment	A share of equity interest in an entity. The most common form is common stock. Equity entitles the holder to a pro rata ownership in the company.
Equity share approach	A consolidation approach whereby a company accounts for GHG emissions from operations according to its share of equity in the operation. The equity share reflects economic interest, which is the extent of rights a company has to the risks and rewards flowing from an operation.
Feed-in tariff	A policy mechanism offering a fixed price to renewable energy producers for output.
Finance lease	A lease that transfers substantially all the risks and rewards of ownership to the lessee and is accounted for as an asset on the balance sheet of the lessee. Also known as a capital or financial lease. Leases other than capital/financial/finance leases are operating leases.
Financial control	The ability to direct the financial and operating policies of an entity with a view to gaining economic benefits from its activities.
Financial control approach	A consolidation approach whereby a company accounts for 100 percent of the GHG emissions over which it has financial control. It does not account for GHG emissions from operations in which it owns an interest but does not have financial control.
Fuel mix disclosure	A report by energy suppliers to their consumers disclosing the generation resources and associated attributes (such as GHG emissions and nuclear waste quantities) provided by that supplier. Disclosure laws often aim to enable informed customer choice in deregulated or liberalized markets.
Generation	The electrical energy produced by a power plant or project activity.

GHG program	A generic term for: (1) any voluntary or mandatory, government or nongovernment initiative, system, or program that registers, certifies, or regulates GHG emissions; or (2) any authorities responsible for developing or administering such initiatives, systems, or programs.
GHG project	A specific activity or set of activities intended to reduce GHG emissions, increase the storage of carbon, or enhance GHG removals from the atmosphere. A GHG project may be a standalone project or a component of a larger non-GHG project.
Global warming potential	A factor describing the radiative forcing impact (degree of harm to the atmosphere) of (GWP) one unit of a given GHG relative to one unit of CO_2.
Green power	A generic term for renewable energy sources and specific clean energy technologies that emit fewer GHG emissions relative to other sources of energy that supply the electric grid. Includes solar photovoltaic panels, solar thermal energy, geothermal energy, landfill gas, low-impact hydropower, and wind turbines. Resources included in a given certification, reporting, or recognition program may vary.
Green power product/ green tariff	A consumer option offered by an energy supplier distinct from the "standard" offering. These are often renewables or other low-carbon energy sources, supported by energy attribute certificates or other contracts.
Greenhouse gas inventory	A quantified list of an organization's GHG emissions and sources.
Greenhouse gases (GHG)	For the purposes of this standard, GHGs are the seven gases covered by the UNFCCC: carbon dioxide (CO_2); methane (CH_4); nitrous oxide (N_2O); hydrofluorocarbons (HFCs); perfluorocarbons (PFCs); sulphur hexafluoride (SF_6), and nitrogen triflouride (NF_3).
Grid	A system of power transmission and distribution (T&D) lines under the control of a coordinating entity or "grid operator," which transfers electrical energy generated by power plants to energy users—also called a "power grid." The boundaries of a power grid are determined by technical, economic, and regulatory-jurisdictional factors.
Grid operator	The entity responsible for implementing procedures to dispatch a set of power plants in a given area to meet demand for electricity in real time. The precise institutional nature of the grid operator will differ from system to system. The grid operator may be alternately referred to as a "system dispatcher," "control area operator," "independent system operator," or "regional transmission organization," etc.
Indirect GHG emissions	Emissions that are a consequence of the operations of the reporting company, but occur at sources owned or controlled by another company. This includes scope 2 and scope 3.
Intensity target	A target defined by reduction in the ratio of emissions and a business metric over time e.g., reduce CO_2 per metric ton of cement by 12 percent between 2000 and 2008.
Intergovernmental Panel on Climate Change (IPCC)	An international body of climate change scientists. The role of the IPCC is to assess the scientific, technical, and socioeconomic information relevant to the understanding of the risk of human-induced climate change
Inventory boundary	An imaginary line that encompasses the direct and indirect emissions included in the inventory. It results from the chosen organizational and operational boundaries.

Inventory quality — The extent to which an inventory provides a faithful, true, and fair account of an organization’s GHG emissions.

Jurisdiction — A geopolitical region under a single legal and regulatory authority. For market boundaries for certificate use and trading described in this uidance, jurisdictions are typically countries but may be multi-country regions.

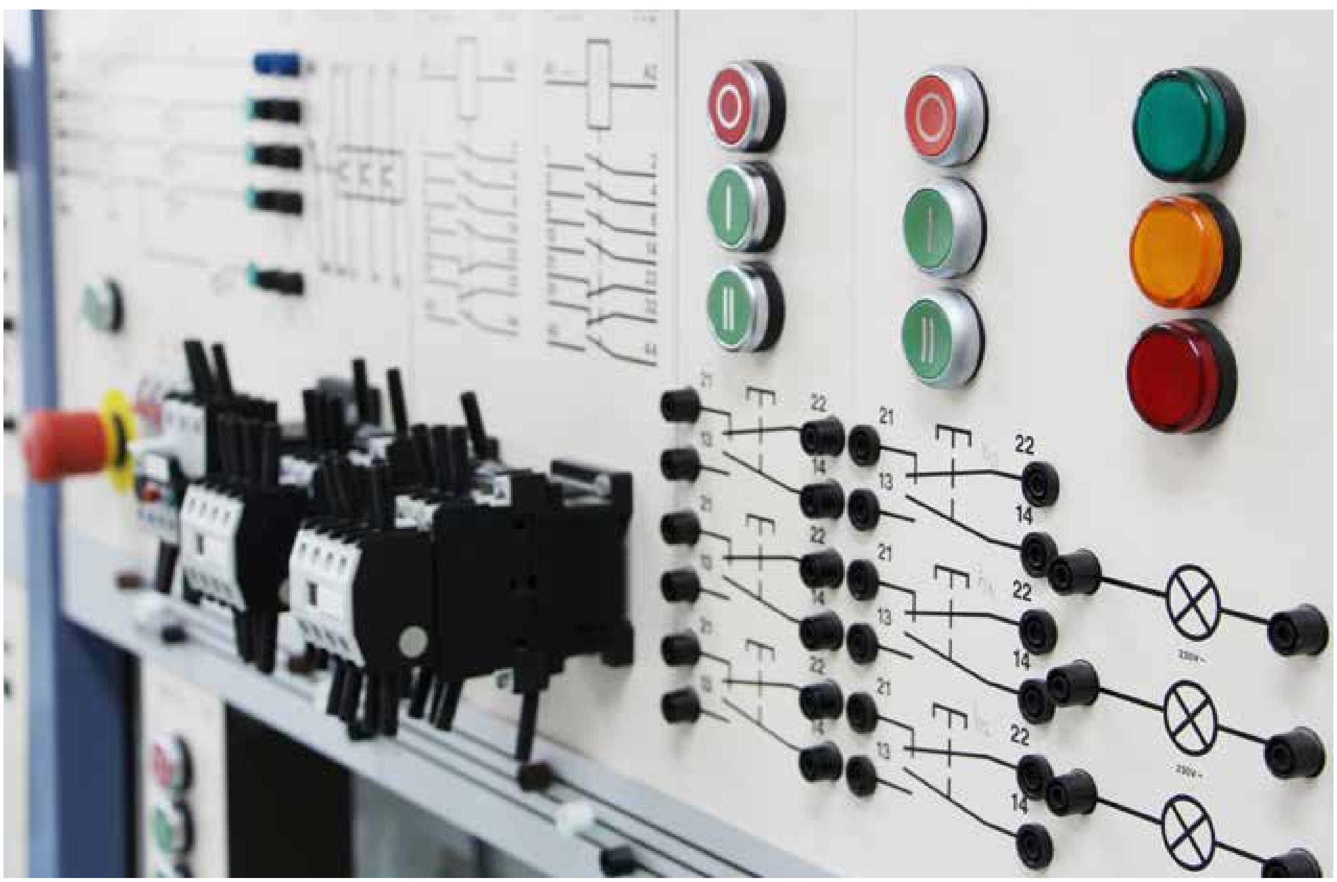
Levy Exemption Certificate (LEC) — Certificates used in the U.K. to provide energy suppliers with evidence needed to demonstrate to HMRC that electricity supplied to U.K. business customers is exempt from the Climate Change Levy.

Life cycle — Consecutive and interlinked stages of a product system, from raw material acquisition or generation of natural resources to end of life.

Life cycle assessment (LCA) — Compilation and evaluation of the inputs, outputs, and the potential environmental impacts of a product system throughout its life cycle.

Location-based method for scope 2 accounting — A method to quantify scope 2 GHG emissions based on average energy generation emission factors for defined locations, including local, subnational, or national boundaries.

Market-based method for scope 2 accounting — A method to quantify scope 2 GHG emissions based on GHG emissions emitted by the generators from which the reporter contractually purchases electricity bundled with instruments, or unbundled instruments on their own.



Megawatt (MW)	A unit of electrical power. One megawatt of power output is equivalent to the transfer of one million joules of electrical energy per second to the grid.
Megawatt-hour (MWh)	A unit of electrical energy equal to 3.6 billion joules; the amount of energy produced over one hour by a power plant with an output of 1 MW.
Net metering	A method for energy suppliers to credit customers for electricity that they generate on site in excess of their own electricity consumption and sell back to the grid. Any electricity purchases from the gird are deducted (or "netted") from the generation sent to the grid. The specific financial rules for net metering may vary by country and state.
Null power	Energy from which energy attribute certificates or other instruments have been separated and sold off, leaving the underlying power without specific attributes. Also called "commodity electricity."
Offset credit	Offset credits (also called offsets, or verified emission reductions) represent the reduction, removal, or avoidance of GHG emissions from a specific project that is used to compensate for GHG emissions occurring elsewhere, for example to meet a voluntary or mandatory GHG target or cap. Offsets are calculated relative to a baseline that represents a hypothetical scenario for what emissions would have been in the absence of the mitigation project that generates the offsets. To avoid double counting, the reduction giving rise to the offset must occur at sources or sinks not included in the target or cap for which it is used.
On-site generation	Electricity generated by a generation facility located where some or all of the energy is used. If the generation facility is owned and operated by the consuming company, it can be called "self-generation." On-site generation is a form of distributed energy generation.
Operating lease	A lease that does not transfer the risks and rewards of ownership to the lessee and is not recorded as an asset in the balance sheet of the lessee. Leases other than operating leases are capital/financial/finance leases.
Operating margin (OM)	The set of existing power plants whose output is reduced in response to a project activity. These power plants are the last to be switched on-line or first to be switched off-line during times when the project activity is operating, and which therefore would have provided the project activity's generation in the baseline scenario.
Operational boundaries	The boundaries that determine the direct and indirect emissions associated with operations owned or controlled by the reporting company.
Operational control	A consolidation approach whereby a company accounts for 100 percent of the GHG emissions over which it has operational control. It does not account for GHG emissions from operations in which it owns an interest but does not have operational control.
Organizational boundaries	The boundaries that determine the operations owned or controlled by the reporting company, depending on the consolidation approach taken (equity or control approach).

Power purchase agreement (PPA)	A type of contract that allows a consumer, typically large industrial or commercial entities, to form an agreement with a specific energy generating unit. The contract itself specifies the commercial terms including delivery, price, payment, etc. In many markets, these contracts secure a long-term stream of revenue for an energy project. In order for the consumer to say they are buying the electricity of the specific generator, attributes **shall** be contractually transferred to the consumer with the electricity.
Renewable energy	Energy taken from sources that are inexhaustible, e.g. wind, water, solar, geothermal energy, and biofuels.
Renewable energy certificate (REC)	A type of energy attribute certificate, used in the U.S. and Australia. In the U.S., a REC is defined as representing the property rights to the generation, environmental, social, and other non-power attributes of renewable electricity generation.
Renewable Portfolio Standards (RPS)	A state- or national-level policy that requires that a minimum amount (usually a percentage) of electricity supply provided by each supply company is to come from renewable energy.
Residual mix	The mix of energy generation resources and associated attributes such as GHG emissions in a defined geographic boundary left after contractual instruments have been claimed/retired/canceled. The residual mix can provide an emission factor for companies without contractual instruments to use in a market-based method calculation.
Retailer (also retail provider)	The entity selling energy to final consumers, representing final process in the delivery of electricity from generation to the consumer. Also known as electric service provider, competitive power supplier or power marketer depending on the national or subnational regulation.
Scope 1 emissions	Emissions from operations that are owned or controlled by the reporting company.
Scope 2 emissions	Indirect emissions from the generation of purchased or acquired electricity, steam, heat or cooling consumed by the reporting company.
Scope 2 Quality Criteria	A set of requirements that contractual instruments **shall** meet in order to be used in the market-based method for scope 2 accounting.
Scope 3 emissions	All indirect emissions (not included in scope 2) that occur in the value chain of the reporting company, including both upstream and downstream emissions.
Scope 3 category	One of the 15 types of scope 3 emissions.
Self-generation	On-site generation owned or operated by the entity that consumes the power.
Significance threshold	A qualitative or quantitative criterion used to define a significant structural change. It is the responsibility of the company, GHG program to which the company is reporting, or the company's verifier to determine the "significance threshold" for considering base-year emissions recalculation. In most cases the "significance threshold" depends on the use of the information, the characteristics of the company, and the features of structural changes.
Supplier	An entity that provides or sells products to another entity (i.e., a customer). For this guidance, refers to electricity supplier.

Supplier quota Regulations requiring electricity suppliers to source a percentage of their supply from specified energy sources, e.g. Renewable Portfolio Standards in U.S. states. Regulations generally defined eligibility criteria that energy facilities must fulfill in order to be used to demonstrate compliance.

Supplier-specific emission factor An emission rate provided by an electricity supplier to its customers, reflecting the emissions associated with the energy it provides. Suppliers offering differentiated products (e.g. a renewable energy product) should provide specific emission rates for each product and ensure they are not double counted with standard power offers.

Supply chain A network of organizations (e.g., manufacturers, wholesalers, distributors and retailers) involved in the production, delivery, and sale of a product to the consumer.

Tracking system A database or registry that helps execute energy attribute certificate issuance and cancellation/retirement/claims between account holders in the system. It can track information on certificates or generation occurring throughout the defined system. They are typically tied to geopolitical or grid operational boundaries.

Unbundled An energy attribute certificate or other instrument that is separate, and may be traded separately, from the underlying energy produced.

Utility See electric utility.

Vintage The date that electric generation occurs and/or was measured, from which an energy attribute certificate is issued. This should be distinguished from an energy facility's age (e.g. date that a generating unit commenced operation).

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Technical Guidance for Calculating Scope 3 Emissions (version 1.0)

Supplement to the Corporate Value Chain (Scope 3) Accounting & Reporting Standard

WORLD RESOURCES INSTITUTE

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Introduction

An effective corporate climate change strategy requires a detailed understanding of a company's greenhouse gas (GHG) emissions. Until recently, companies have focused on emissions from their own operations under scope 1 and scope 2 of the GHG Protocol. Increasingly companies understand the need to also account for GHG emissions along their value chains and product portfolios to comprehensively manage GHG-related risks and opportunities.

The GHG Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard *(referred to as the* Scope 3 Standard*), the parent document to this guidance, offers an internationally accepted method to enable GHG management of companies' value chains. This guidance document serves as a companion to the* Scope 3 Standard *to offer companies practical guidance on calculating their scope 3 emissions. It provides information not contained in the* Scope 3 Standard, *such as methods for calculating GHG emissions for each of the 15 scope 3 categories, data sources, and worked examples.*

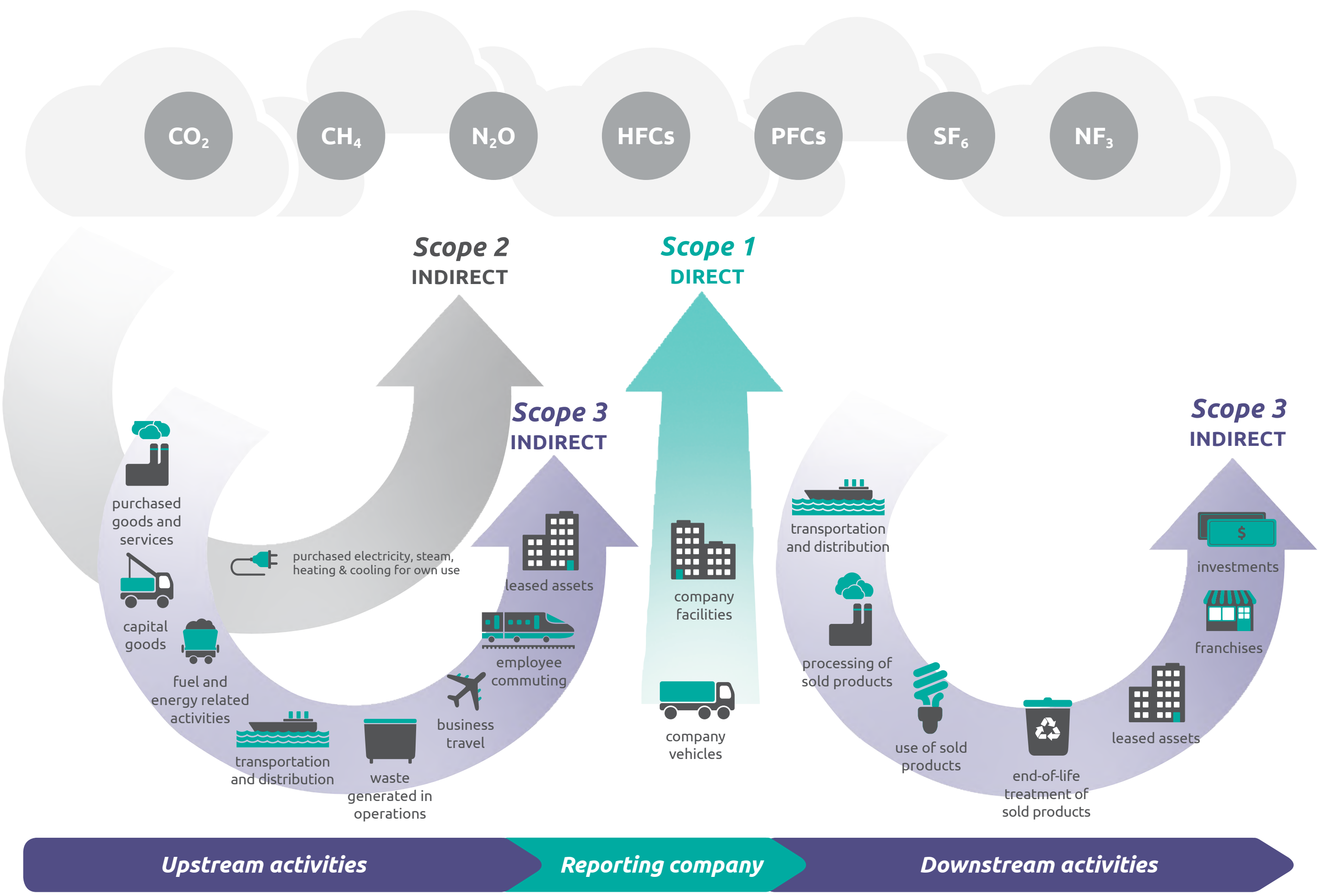
Please refer to the Scope 3 Standard *for requirements and guidance related to scope 3 accounting and reporting.*

Descriptions of scope 3 categories

Figure I shows the 15 distinct reporting categories in scope 3 and also shows how scope 3 relates to scope 1 (direct emissions from owned or controlled sources) and scope 2 (indirect emissions from the generation of purchased purchased electricity, steam, heating and cooling consumed by the reporting company). Scope 3 includes all other indirect emissions that occur in a company's value chain. The 15 categories in scope 3 are intended to provide companies with a systematic framework to measure, manage, and reduce emissions across a corporate value chain. The categories are designed to be mutually exclusive to avoid a company double counting emissions among categories.

Table I gives descriptions of each of the 15 categories. The Scope 3 Standard requires companies to quantify and report scope 3 emissions from each category.

Figure [I] Overview of GHG Protocol scopes and emissions across the value chain



Source: Figure 1.1 of *Scope 3 Standard.*

Table [I] Description and boundaries of scope 3 categories

Upstream scope 3 emissions

Category	*Category description*	*Minimum boundary*
1. Purchased goods and services	• Extraction, production, and transportation of goods and services purchased or acquired by the reporting company in the reporting year, not otherwise included in Categories 2 - 8	• All upstream (cradle-to-gate) emissions of purchased goods and services
2. Capital goods	• Extraction, production, and transportation of capital goods purchased or acquired by the reporting company in the reporting year	• All upstream (cradle-to-gate) emissions of purchased capital goods
3. Fuel- and energy-related activities (not included in scope 1 or scope 2)	• Extraction, production, and transportation of fuels and energy purchased or acquired by the reporting company in the reporting year, not already accounted for in scope 1 or scope 2, including: **a.** Upstream emissions of purchased fuels (extraction, production, and transportation of fuels consumed by the reporting company) **b.** Upstream emissions of purchased electricity (extraction, production, and transportation of fuels consumed in the generation of electricity, steam, heating, and cooling consumed by the reporting company) **c.** Transmission and distribution (T&D) losses (generation of electricity, steam, heating and cooling that is consumed (i.e., lost) in a T&D system) – reported by end user **d.** Generation of purchased electricity that is sold to end users (generation of electricity, steam, heating, and cooling that is purchased by the reporting company and sold to end users) – reported by utility company or energy retailer only	**a.** For upstream emissions of purchased fuels: All upstream (cradle-to-gate) emissions of purchased fuels (from raw material extraction up to the point of, but excluding combustion) **b.** For upstream emissions of purchased electricity: All upstream (cradle-to-gate) emissions of purchased fuels (from raw material extraction up to the point of, but excluding, combustion by a power generator) **c.** For T&D losses: All upstream (cradle-to-gate) emissions of energy consumed in a T&D system, including emissions from combustion **d.** For generation of purchased electricity that is sold to end users: Emissions from the generation of purchased energy

Table [I] Description and boundaries of scope 3 categories (continued)

Upstream scope 3 emissions

Category	*Category description*	*Minimum boundary*
4. Upstream transportation and distribution	• Transportation and distribution of products purchased by the reporting company in the reporting year between a company's tier 1 suppliers and its own operations (in vehicles and facilities not owned or controlled by the reporting company) • Transportation and distribution services purchased by the reporting company in the reporting year, including inbound logistics, outbound logistics (e.g., of sold products), and transportation and distribution between a company's own facilities (in vehicles and facilities not owned or controlled by the reporting company)	• The scope 1 and scope 2 emissions of transportation and distribution providers that occur during use of vehicles and facilities (e.g., from energy use) • ***Optional:*** The life cycle emissions associated with manufacturing vehicles, facilities, or infrastructure
5. Waste generated in operations	• Disposal and treatment of waste generated in the reporting company's operations in the reporting year (in facilities not owned or controlled by the reporting company)	• The scope 1 and scope 2 emissions of waste management suppliers that occur during disposal or treatment • ***Optional:*** Emissions from transportation of waste
6. Business travel	• Transportation of employees for business-related activities during the reporting year (in vehicles not owned or operated by the reporting company)	• The scope 1 and scope 2 emissions of transportation carriers that occur during use of vehicles (e.g., from energy use) • ***Optional:*** The life cycle emissions associated with manufacturing vehicles or infrastructure
7. Employee commuting	• Transportation of employees between their homes and their worksites during the reporting year (in vehicles not owned or operated by the reporting company)	• The scope 1 and scope 2 emissions of employees and transportation providers that occur during use of vehicles (e.g., from energy use) • ***Optional:*** Emissions from employee teleworking
8. Upstream leased assets	• Operation of assets leased by the reporting company (lessee) in the reporting year and not included in scope 1 and scope 2 – reported by lessee	• The scope 1 and scope 2 emissions of lessors that occur during the reporting company's operation of leased assets (e.g., from energy use) • ***Optional:*** The life cycle emissions associated with manufacturing or constructing leased assets

Table [I] Description and boundaries of scope 3 categories (continued)

Downstream scope 3 emissions

Category	*Category description*	*Minimum boundary*
9. Downstream transportation and distribution	• Transportation and distribution of products sold by the reporting company in the reporting year between the reporting company's operations and the end consumer (if not paid for by the reporting company), including retail and storage (in vehicles and facilities not owned or controlled by the reporting company)	• The scope 1 and scope 2 emissions of transportation providers, distributors, and retailers that occur during use of vehicles and facilities (e.g., from energy use) • ***Optional:*** The life cycle emissions associated with manufacturing vehicles, facilities, or infrastructure
10. Processing of sold products	• Processing of intermediate products sold in the reporting year by downstream companies (e.g., manufacturers)	• The scope 1 and scope 2 emissions of downstream companies that occur during processing (e.g., from energy use)
11. Use of sold products	• End use of goods and services sold by the reporting company in the reporting year	• The direct use-phase emissions of sold products over their expected lifetime (i.e., the scope 1 and scope 2 emissions of end users that occur from the use of: products that directly consume energy (fuels or electricity) during use; fuels and feedstocks; and GHGs and products that contain or form GHGs that are emitted during use) • ***Optional:*** The indirect use-phase emissions of sold products over their expected lifetime (i.e., emissions from the use of products that indirectly consume energy (fuels or electricity) during use)
12. End-of-life treatment of sold products	• Waste disposal and treatment of products sold by the reporting company (in the reporting year) at the end of their life	• The scope 1 and scope 2 emissions of waste management companies that occur during disposal or treatment of sold products
13. Downstream leased assets	• Operation of assets owned by the reporting company (lessor) and leased to other entities in the reporting year, not included in scope 1 and scope 2 – reported by lessor	• The scope 1 and scope 2 emissions of lessees that occur during operation of leased assets (e.g., from energy use). • ***Optional:*** The life cycle emissions associated with manufacturing or constructing leased assets

Table [I] Description and boundaries of scope 3 categories (continued)

Downstream scope 3 emissions

Category	*Category description*	*Minimum boundary*
14. Franchises	• Operation of franchises in the reporting year, not included in scope 1 and scope 2 – reported by franchisor	• The scope 1 and scope 2 emissions of franchisees that occur during operation of franchises (e.g., from energy use) • ***Optional:*** The life cycle emissions associated with manufacturing or constructing franchises
15. Investments	• Operation of investments (including equity and debt investments and project finance) in the reporting year, not included in scope 1 or scope 2	• See the description of category 15 (Investments) in section 5.5 for the required and optional boundaries

Source: Table 5.4 from the *Scope 3 Standard*

How to use this document

The 15 sections in this document correspond to the 15 scope 3 categories in table II. Each section follows the structure below:

- Category description (from chapter 5 of the *Scope 3 Standard*)
- Summary of calculation methods (and decision tree if applicable)
- For each calculation method:
  - Activity data needed
  - Emission factors needed
  - Data collection guidance
  - Calculation formula
  - Example(s)

The Scope 3 Standard contains a lot of important information that is not repeated in this calculation guidance document, including business goals for conducting a scope 3 assessment; accounting and reporting principles; setting the scope 3 boundary; setting reduction targets; and reporting. This document should be used in conjunction with the *Scope 3 Standard* when calculating emissions. The following Scope 3 Standard chapters contain information that is especially relevant to performing various emissions calculations:

- Chapter 4, which defines the accounting and reporting principles (relevance, completeness, consistency, transparency, accuracy)
- Chapter 5, which defines each of the 15 scope 3 categories and provides detailed descriptions of which activities are included in each scope 3 category
- Chapter 6, which provides guidance on setting the scope 3 boundary
- Chapter 7, which provides guidance on collecting data, including prioritizing data collection efforts, selecting among different types of data, and ensuring data quality
- Chapter 8, which provides guidance on allocating emissions
- Chapter 10, which describes assurance procedures
- Chapter 11, which defines scope 3 reporting requirements
- Appendix B, which describes uncertainty in scope 3 inventories
- Appendix C, which describes how to create a data management plan

Selecting calculation methods

For most scope 3 categories, this document offers multiple calculation methods. Within each section, the calculation methods are ranked in order of specificity,[1] from most to least specific to a company's actual activities. In general, more specific methods yield higher quality scope 3 emissions data whereas less specific methods yield lower quality scope 3 emissions data. However, the more specific methods are often more time and labor intensive. The best method for each category depends on factors described below.

Companies should select calculation methods for each scope 3 activity within a category based on the following criteria:

- The relative size of the emissions from the scope 3 activity
- The company's business goals (see chapter 2 of the *Scope 3 Standard*)
- Data availability
- Data quality
- The cost and effort required to apply each method
- Other criteria identified by the company.

Companies should select calculation methods that ensure that the inventory appropriately reflects the GHG emissions of the activities and serves the decision-making needs of users, both internal and external to the company.

Note that each scope 3 category may contain multiple activities (for example air travel and road travel could be two different activities within category 6, Business travel). If appropriate, different calculation methods can be used to calculate emissions from different activities within a category. This guide uses the term "should" to indicate recommendations for calculations.

Companies are required to report a description of the methodologies used to calculate emissions for each scope 3 category (see chapter 9 of the *Scope 3 Standard*).

Screening to prioritize data collection

The *Scope 3 Standard* recommends that companies identify which scope 3 activities are expected to have the most significant GHG emissions, offer the most significant GHG reduction opportunities, and are most relevant to the company's business goals. Companies should begin by conducting a screening process, using less specific data, to determine the size of GHG emissions in each of the 15 categories. Then each category can be examined to determine whether to further refine its emission estimates.

This document offers guidance on how to decide which categories require a more precise, and often more labor-intensive, method of data collection, and which might be adequately served by a less precise method. In most cases, the categories that generate the largest amount of emissions should receive the most precise data collection treatment, however, some smaller categories that are important to customers or employees may benefit from more precise treatment as well. Categories most relevant to the company's business goals may also receive more attention. The business goals most frequently cited by companies as reasons for developing a scope 3 inventory were to: (1) identify and understand the risks and opportunities associated with value chain emissions; (2) identify GHG reduction opportunities, set reduction targets, and track performance; and (3) engage value chain partners in GHG management. See chapter 2 of the *Scope 3 Standard*.

1 If a calculation method is specific to a company's activity, the calculation is based on data relating directly to the particular activity in question, such as data collected from a transport provider relating to journeys carried out. In contrast, less specific methods use data that does not directly relate to the activity, such as industry average emission factors.

Collecting higher quality data for priority activities allows companies to focus resources on the most significant GHG emissions in the value chain, more effectively set reduction targets, and track and demonstrate GHG reductions over time.

As a result of the screening, a company might decide that, in addition to using more precise data for activities with the most emissions, it will seek higher quality data for activities that present the most significant risks and opportunities in the value chain, and for activities where more accurate data can be easily obtained. Conversely, it may choose to rely on relatively less accurate data for activities that are expected to have insignificant emissions or where accurate data is difficult to obtain.

To start the screening, a company can apply the criteria in table II to each of the 15 categories to find out where the bulk of its scope 3 GHG emissions occur. Note that to facilitate the initial screening, companies can use the less specific calculation methods listed for each category (i.e., the methods at the bottom of the decision trees). See section 7.1 of the *Scope 3 Standard* for more guidance on prioritizing data collection efforts. More specific methods can be applied later to priority categories.

Table [II] Criteria for identifying relevant scope 3 activities

Criteria	*Description of activities*
Size	They contribute significantly to the company's total anticipated scope 3 emissions
Influence	There are potential emissions reductions that could be undertaken or influenced by the company
Risk	They contribute to the company's risk exposure (e.g., climate change related risks such as financial, regulatory, supply chain, product and technology, compliance/litigation, and reputational risks)
Stakeholders	They are deemed critical by key stakeholders (e.g., customers, suppliers, investors or civil society)
Outsourcing	They are outsourced activities previously performed in-house or activities outsourced by the reporting company that are typically performed in-house by other companies in the reporting company's sector
Sector guidance	They have been identified as significant by sector-specific guidance
Spending or revenue analysis	They are areas that require a high level of spending or generate a high level of revenue (and are sometimes correlated with high GHG emissions)
Other	They meet any additional criteria developed by the company or industry sector

Source: Adapted from table 6.1 from the *Scope 3 Standard*

Using a combination of calculation methods

Companies may use a combination of calculation methods for various scope 3 categories throughout the inventory, as well as for various scope 3 activities within each scope 3 category. For example, within each scope 3 category, a company may use more specific methods for the activities that contribute most to emissions and less specific methods for the activities that contribute least to emissions.

Companies should take practical approaches to reduce costs and complexity without overly compromising quality. These may include:

- Applying more accurate data/calculations for large contributors
- Applying less accurate data/calculations for small contributors
- Grouping or combining similar activity data (e.g., goods and services)
- Obtaining data from representative samples and extrapolating the results to the whole
- Using proxy techniques.

Example: Using a combination of calculation methods

A coffee company purchased coffee beans from 100 different suppliers in the reporting year. If 10 of these suppliers account for 85 percent of the quantity of purchased beans, the company may decide to calculate emissions associated with the coffee beans from these 10 suppliers using primary data collected from the suppliers, either using the “supplier-specific method” or the “hybrid method” (see chapter 1 for descriptions of the calculation methods for scope 3 category 1). The company may then choose to extrapolate to 100 percent based on the 85 percent of the beans for which data was collected.

The company spent a total of $20 million on purchasing coffee beans. The company also purchased a small quantity of sugar, totaling $1 million for the year. As the sugar only accounts for a small proportion of the company’s total expenditure, the company may choose not to engage with the sugar suppliers, but instead use secondary emission factors, using either the “average-data method” or the “spend-based method.”

Significance of an activity’s emission contribution to the inventory is a key consideration when determining the appropriate level of data specificity to calculate the emissions.

Overview of data types

Calculating emissions requires the use of two types of data: activity data and emission factors.

“Activity data” is a quantitative measure of a level of activity that results in GHG emissions (for example, liters of fuel consumed, or kilograms of material purchased). An “emission factor” is a factor that converts activity data into GHG emissions data (for example kg CO_2 emitted per liter of fuel consumed, or kg CO_2 emitted per kilograms of material produced). More examples of activity data and emission factors are provided in table 7.2 in the *Scope 3 Standard*.

Companies are required to report a description of the types and sources of activity data and emission factors used to calculate the inventory (see chapter 11 in the *Scope 3 Standard*).

Material/product emission factors in scope 3 accounting

Two types of emission factors can be used for calculating emissions associated with a material or product:

- **Life cycle emission factors**, which include emissions that occur at every stage of a material/product's life, from raw material acquisition or generation of natural resource to end of life
- **Cradle-to-gate (sometimes referred to as "upstream") emission factors**, which include all emissions that occur in the life cycle of a material/product up to the point of sale by the producer.

In general, cradle-to-gate emission factors should be used to calculate emissions associated with goods or services (e.g. category 1 (Purchased goods and services) and category 2 (Capital goods).

Energy emission factors in scope 3 accounting

Two types of emission factors are used to convert energy activity data into emissions data:

- **Life cycle emission factors**, which include not only the emissions that occur from combusting the fuel, but all other emissions that occur in the life cycle of the fuel such as emissions from extraction, processing, and transportation
- **Combustion emission factors**, which include only the emissions that occur from combusting the fuel.

Companies should use life cycle emission factors to calculate scope 3 emissions related to fuels and energy consumed in the reporting company's value chain, except for category 3 (Fuel- and energy-related activities not included in scope 1 or scope 2). Combustion emission factors are used to calculate scope 1 emissions (in the case of fuels) and scope 2 emissions (in the case of electricity).

Two activities within scope 3 category 3 require special consideration when selecting emission factors:

- **Upstream emissions of purchased fuels** (i.e., extraction, production, and transportation of fuels consumed by the reporting company)
- **Upstream emissions of purchased electricity** (i.e., extraction, production, and transportation of fuels consumed in the generation of electricity, steam, heating, and cooling that is consumed by the reporting company).

To calculate emissions from these two activities, companies should use emission factors that include upstream emissions (i.e., extraction, production, and transportation) but exclude emissions from combustion, since emissions from combustion are accounted for in scope 1 (in the case of fuels), in scope 2 (in the case of electricity), and in a separate memo item (in the case of direct CO_2 emissions from combustion of biomass or biofuels). See Chapter 3 of the *Scope 3 Standard*.

These emission factors that exclude combustion are referred to as "upstream emission factors," since they include all life cycle stages of the fuel up to but excluding the final stage – combustion.

Applicable greenhouse gases and global warming potential values

For each of the 15 scope 3 categories, companies are required to calculate emissions of all the GHGs required by the United Nations Framework Convention on Climate Change (UNFCCC)/Kyoto Protocol at the time the inventory is being compiled. National reporting guidelines under the UNFCCC and the Kyoto Protocol require that specific GHGs be included in national GHG emissions inventories. To remain consistent with national inventory practices, the GHG Protocol requires that these same GHGs also be reported in corporate GHG emissions inventories. Originally, the requirements of the UNFCCC/Kyoto Protocol, and therefore of the GHG Protocol, were limited to a set of six individual GHGs or classes of GHGs: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulphur hexafluoride (SF_6). However, changes to international accounting and reporting rules under the UNFCCC/Kyoto Protocol now also require the reporting of another GHG, nitrogen trifluoride (NF_3).

As the *Scope 3 Standard* was released before NF_3 was added to the list of GHGs covered by UNFCCC/Kyoto Protocol, reporting NF_3 was not originally included as a requirement in the Scope 3 Standard. However an amendment has been published on the GHG Protocol website (http://www.ghgprotocol.org/) which supersedes the original requirements of the *Scope 3 Standard* and it is now a requirement that NF_3 be included.

In this document, carbon dioxide equivalent (CO_2e) emissions represent emissions of all greenhouse gases, aggregated and converted to units of CO_2e using global warming potential (GWP) values.

GWP values describe the radiative forcing impact (or degree of harm to the atmosphere) of one unit of a given GHG relative to one unit of carbon dioxide. GWP values convert GHG emissions data for non-CO_2 gases into units of CO_2e.

Companies may either use the Intergovernmental Panel on Climate Change (IPCC) GWP values agreed to by United Nations Framework Convention on Climate Change (UNFCCC) or the most recent GWP values published by the IPCC. GWP values should be based on a 100-year time horizon. See section 7.2 of the *Scope 3 Standard* for more information on GWP values. Companies are required to disclose the source of GWP values used to calculate the inventory (see chapter 11 of the *Scope 3 Standard*).

Primary data and secondary data

Companies may use either primary or secondary data to calculate scope 3 emissions. Table III provides definitions of these types of data.

Table [III] Types of data

Data type	*Description*
Primary Data	Data from specific activities within a company's value chain
Secondary Data	Data that is not from specific activities within a company's value chain

Source: Table 7.4 from the *Scope 3 Standard.*

Primary data includes data provided by suppliers or others that directly relate to specific activities in the reporting company's value chain.

Secondary data includes industry-average-data (e.g., from published databases, government statistics, literature studies, and industry associations), financial data, proxy data, and other generic data. In certain cases, companies may use specific data from one activity in the value chain to estimate emissions for another activity in the value chain. This type of data (i.e., proxy data) is considered secondary data, since it is not specific to the activity whose emissions are being calculated.

See table 7.4 in the *Scope 3 Standard* for examples of primary and secondary data by scope 3 category.

Collecting primary data

Primary activity data may be obtained through meter readings, purchase records, utility bills, engineering models, direct monitoring, mass balance, stoichiometry, or other methods for obtaining data from specific activities in the company's value chain.

If possible, companies should collect energy or emissions data from suppliers and other value chain partners to obtain site-specific data for priority scope 3 categories and activities (see "Screening to prioritize data collection," above, for guidance on identifying priority categories). To do so, companies should identify relevant suppliers from which to seek GHG data. Suppliers may include contract manufacturers, materials and parts suppliers, capital equipment suppliers, fuel suppliers, third-party logistics providers, waste management companies, and other companies that provide goods and services to the reporting company.

In general, companies should seek activity data or emissions data from suppliers that are as specific as possible to the product purchased from the supplier, following the hierarchy in table IV.

Table [IV] Levels of data (ranked in order of specificity)

Data Type	*Description*
Product-level data	Cradle-to-gate GHG emissions for the product of interest
Activity-, process-, or production line-level data	GHG emissions and/or activity data for the activities, processes, or production lines that produce the product of interest
Facility-level data	GHG emissions and/or activity data for the facilities or operations that produce the product of interest
Business-unit-level data	GHG emissions and/or activity data for the business units that produce the product of interest
Corporate-level data	GHG emissions and/or activity data for the entire corporation

Source: Table 7.7 from the *Scope 3 Standard*.

For more information on collecting primary data and guidance on issues such as how to treat the confidentiality concerns of suppliers, refer to section 7.4 of the *Scope 3 Standard*.

Collecting secondary data

When using secondary databases, companies should prefer those that are internationally recognized, provided by national governments, or peer-reviewed. Companies can use the data-quality indicators in section 7.3 of the Scope 3 Standard to select the secondary data sources that are the most complete, reliable, and representative to the company's activities in terms of technology, time, and geography.

Secondary data sources can cover different stages in the value chain. Care should be taken to understand the boundaries covered by the data to minimize the potential for double counting errors across the value chain.

The secondary data sources included in the calculation resources of each category are examples and not an exhaustive list. The GHG Protocol website has a more comprehensive list of secondary data sources at: http://www.ghgprotocol.org/Third-Party-Databases.

For additional guidance on prioritizing data collection efforts, selecting data, collecting data, and filling data gaps, see chapter 7 of the *Scope 3 Standard*.

Environmentally-extended input output (EEIO) data

Environmentally-extended input output (EEIO) models estimate energy use and/or GHG emissions resulting from the production and upstream supply chain activities of different sectors and products in an economy. The resulting EEIO emissions factors can be used to estimate cradle-to-gate GHG emissions for a given industry or product category. EEIO data are particularly useful in screening emissions sources when prioritizing data collection efforts. EEIO models are derived by allocating national GHG emissions to groups of finished products based on economic flows between industry sectors.

The output of EEIO models is typically a quantity of GHGs emitted per unit of revenue in a particular industry sector. For example, an EEIO model may estimate that the sector "paper mills" emits 1,520 tonnes CO_2e per $1 million revenue, meaning that, on average, 1,520 tonnes of CO_2e are emitted during all upstream supply chain activities associated with generating $1 million revenue from that sector.

The advantages of EEIO data include:

- Comprehensive coverage of the entire economy (i.e., no emissions sources are excluded from the system boundary)
- Simplicity of method and application
- Time and cost savings as data requirements are less onerous than in a process-based approach.

The disadvantages of EEIO data include:

- Broad sector averages may not represent nuances of unique processes and products, especially for non-homogenous sectors
- Assumption of linear attribution between monetary and environmental flows provides only indicative results (i.e., EEIO models cannot distinguish between products of different monetary value within a single sector)
- Lacks specificity and accuracy of process-based approaches
- Difficult to measure and demonstrate results of reduction efforts
- EEIO databases are generally limited to a specific geographic region, (e.g., United States) and are not available in some world regions.

Process-based data

Process-based data is derived from assessing all the known energy and environmental inputs of a particular process and calculating the direct emissions associated with the outputs of the process. It is particularly applicable for unique processes and individual product level analysis.

The advantages of process-based data include:

- High level of specificity and focus
- Detailed analysis and possibility of unique insights to particular processes
- Straightforward concept.

The disadvantages of process based data include:

- Collection of data may be time, cost, and labor intensive
- Lack of comparability as the system boundary and the data are selected by the practitioner
- Data requirements may render large-scale, multi-product analysis impractical.

Combining EEIO and process-based data

Companies may combine the top down EEIO approach with the bottom-up, process-based approach to leverage the benefits of both approaches. For example, the upstream emissions of purchased goods could be calculated using an EEIO approach, whereas downstream emissions from use and end-of-life could be calculated using a process-based approach.

Companies are required to report a description of the types and sources of data used to calculate emissions for each scope 3 category (see chapter 11 of the *Scope 3 Standard*).

Using proxy data to fill data gaps

Companies should use the guidance in section 7.3 of the *Scope 3 Standard,* "Guidance for selecting data" to assess the quality of available data. If data of sufficient quality are not available, companies may use proxy data to fill data gaps. Proxy data is data from a similar activity that is used as a stand-in for the given activity. Proxy data can be extrapolated, scaled up, or customized to be more representative of the given activity (e.g., partial data for an activity can be extrapolated or scaled up to represent 100 percent of the activity).

If a large company has access to 80 out of 100 manufacturing facilities it can extrapolate this information to fill the gap. It would first group the activity data by similar characteristics, such as facility type or location, then calculate an intensity ratio for a group of facilities where data is available (e.g., quantity of emissions per unit of production output). This figure can then be applied to the unknown facilities in that group.

Section 7.5 of the *Scope 3 Standard* "Guidance for collecting secondary data and filling data gaps" provides more information on the use of proxy data and its advantages and disadvantages.

If data are unavailable for a large number of sites or if a company needs to collect a large quantity of data for a scope 3 category, but finds it impractical or impossible to collect data from each individual activity, the company may use appropriate sampling techniques to extrapolate data from a representative sample of activities. See Appendix A for guidance on sampling methods.

Improving data quality over time

Collecting data, assessing data quality, and improving data quality is an iterative process. When selecting data sources, companies should first apply data quality indicators and assess data quality, then review the quality of the collected data, using the same data quality assessment approach. In their initial years of scope 3 data collection, companies may need to use data of relatively low quality due to limited availability. Over time, companies should seek to improve the data quality of the inventory by replacing lower quality data with higher quality data as it becomes available. In particular, companies should prioritize data quality improvement for activities that have:

- Relatively low data quality
- Relatively high emissions.

Companies are required to provide a description of the data quality of reported scope 3 emissions data to ensure transparency and avoid misinterpretation of data (see chapter 11 of the *Scope 3 Standard*). Refer to section 7.3 for guidance on describing data quality; Appendix B for guidance on uncertainty; and section 9.3 for guidance on recalculating base year emissions when making improvements in data quality over time.

It is unlikely that all of a company's relevant suppliers will be able to provide it with GHG inventory data. (See table 7.8 of the *Scope 3 Standard* for a list of challenges and guidance for collecting primary data from suppliers.) In such cases, companies should encourage suppliers to develop GHG inventories in the future and may communicate their efforts to encourage more suppliers to provide GHG emissions data in the public report.

If changes in data quality result in significant differences in emissions estimates, companies are required to recalculate base year emissions applying the new data sources. Refer to page 106 of the *Scope 3 Standard* for guidance on base year recalculations for improvements in data accuracy over time. Appendix C of the *Scope 3 Standard* also provides a useful resource for developing a data management plan and improving data management.

GHG Protocol publications and tools

Several GHG publications and calculation tools offer help in calculating emissions from various scope 3 categories. In particular, several cross-sector and sector-specific calculation tools available on the GHG Protocol website (http://www.ghgprotocol.org/calculation-tools/all-tools) provide step-by-step guidance together with electronic worksheets to help companies calculate GHG emissions from specific sources or sectors.

1

Category 1: Purchased Goods and Services

Category description

This category includes all upstream (i.e., cradle-to-gate) emissions from the production of products purchased or acquired by the reporting company in the reporting year. Products include both goods (tangible products) and services (intangible products).

Category 1 includes emissions from all purchased goods and services not otherwise included in the other categories of upstream scope 3 emissions (i.e., category 2 through category 8). Specific categories of upstream emissions are separately reported in category 2 through category 8 to enhance the transparency and consistency of scope 3 reports.

Emissions from the transportation of purchased products from a tier one (direct) supplier to the reporting company (in vehicles not owned or controlled by the reporting company) are accounted for in category 4 (Upstream transportation and distribution).

Companies may find it useful to differentiate between purchases of production-related products (e.g., materials, components, and parts) and non-production-related products (e.g., office furniture, office supplies, and IT support). This distinction may be aligned with procurement practices and therefore may be a useful way to more efficiently organize and collect data (see box 5.2 of the *Scope 3 Standard*).

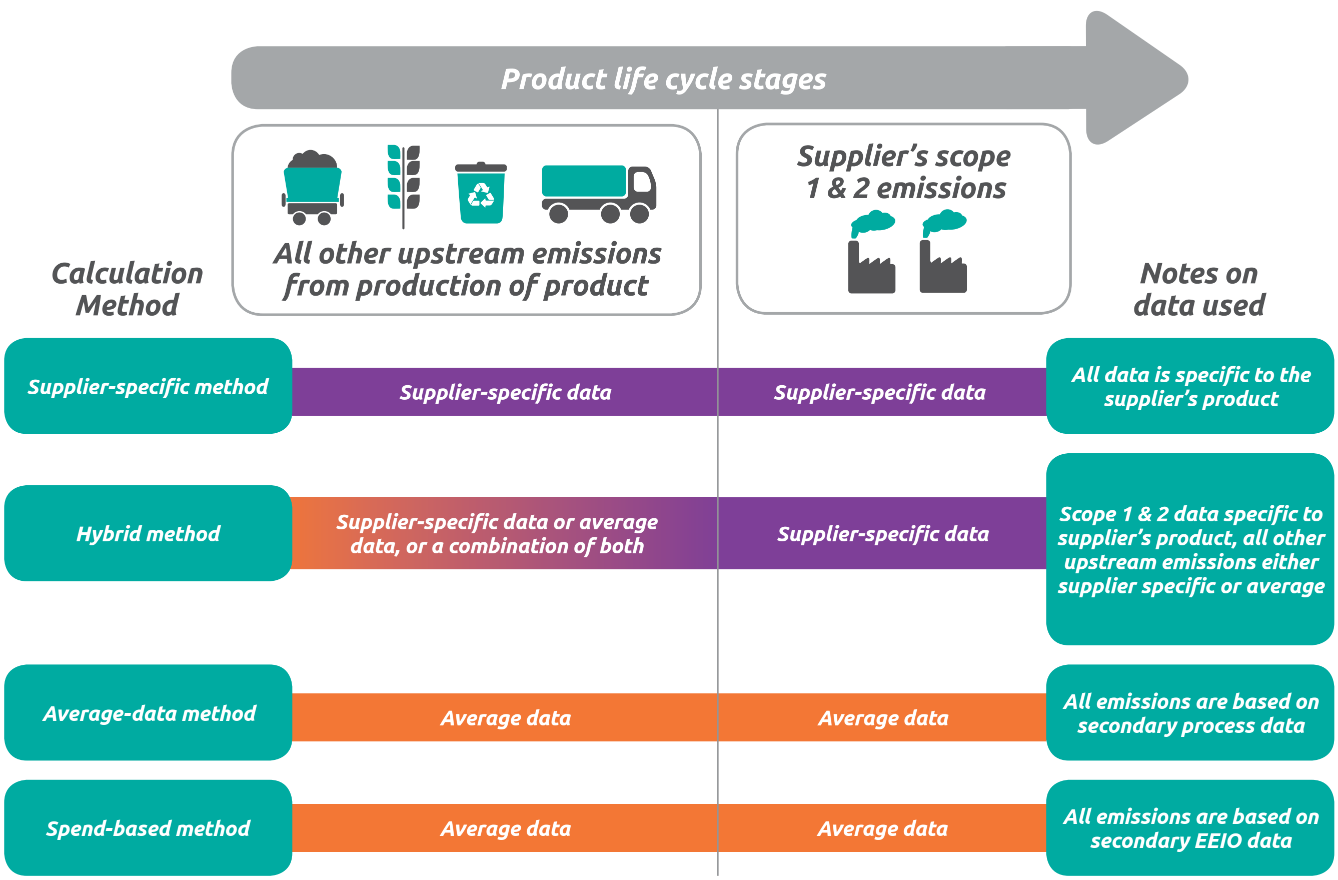
Summary of methods for calculating emissions from purchased goods and services

Companies may use the methods listed below to calculate scope 3 emissions from purchased goods and services. The first two methods – supplier-specific and hybrid – require the reporting company to collect data from the suppliers, whereas the second two methods – average-data and spend-based – use secondary data (i.e. industry average data). These methods are listed in order of how specific[2] the calculation is to the individual supplier of a good or service. However, companies need not always use the most specific method as a first preference (see figure 1.1 and box 1.1).

2 See Box 1.1 for further explanation of the data specificity and data accuracy

- **Supplier-specific method –** collects product-level cradle-to-gate GHG inventory data from goods or services suppliers.
- **Hybrid method –** uses a combination of supplier-specific activity data (where available) and secondary data to fill the gaps. This method involves:
  - collecting allocated scope 1 and scope 2 emission data directly from suppliers;
  - calculating upstream emissions of goods and services from suppliers' activity data on the amount of materials, fuel, electricity, used, distance transported, and waste generated from the production of goods and services and applying appropriate emission factors; and
  - using secondary data to calculate upstream emissions wherever supplier-specific data is not available.
- **Average-data method –** estimates emissions for goods and services by collecting data on the mass (e.g., kilograms or pounds), or other relevant units of goods or services purchased and multiplying by the relevant secondary (e.g., industry average) emission factors (e.g., average emissions per unit of good or service).
- **Spend-based method –** estimates emissions for goods and services by collecting data on the economic value of goods and services purchased and multiplying it by relevant secondary (e.g., industry average) emission factors (e.g., average emissions per monetary value of goods).

Figure [1.1] Different data types used for different calculation methods



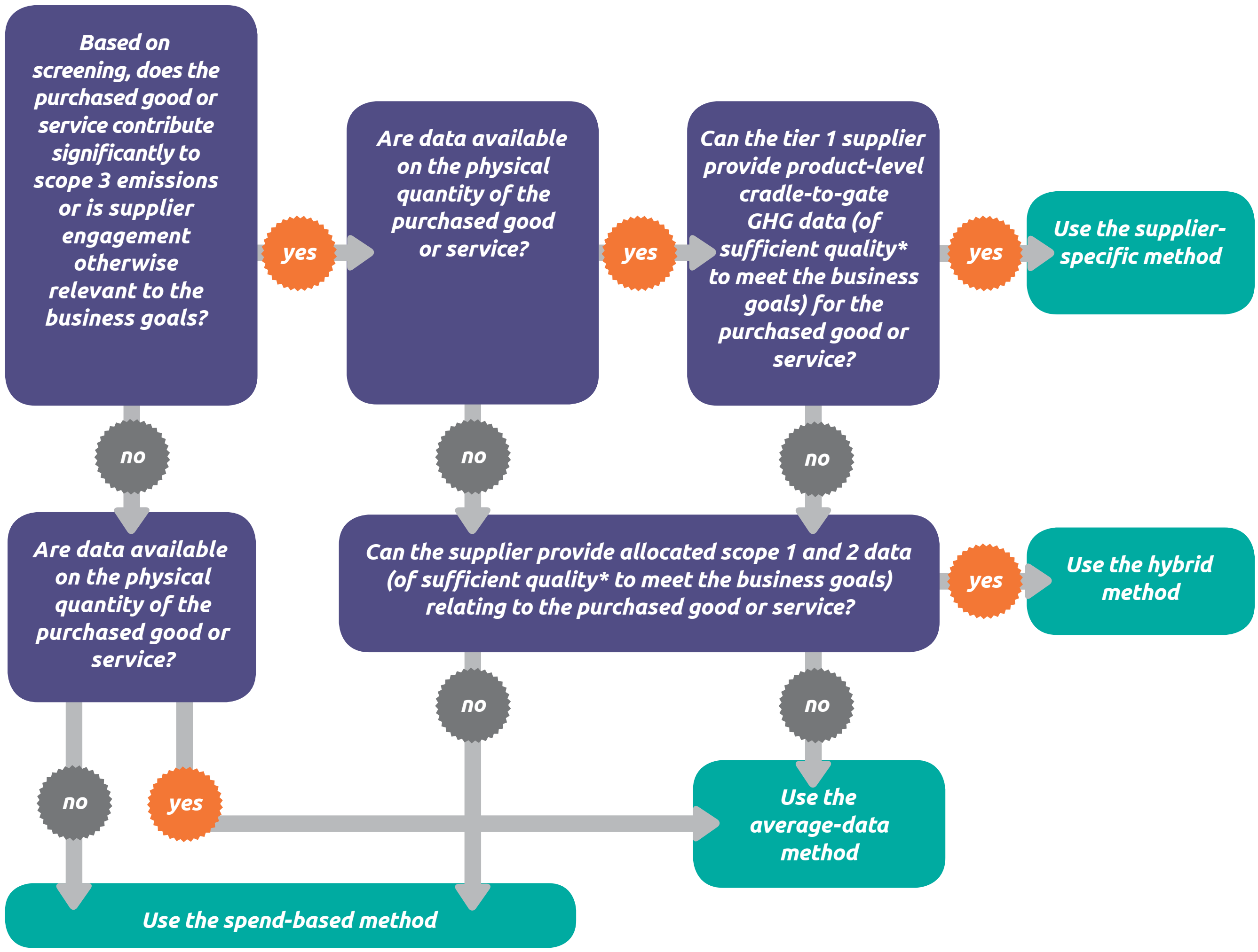
Collecting data directly from suppliers adds considerable time and cost burden to conducting a scope 3 inventory, so companies should first carry out a screening (see Introduction, "Screening to prioritize data collection") to prioritize data collection and decide which calculation method is most appropriate to achieve their business goals.

Box [1.1] The difference between data specificity and data accuracy

Even though the supplier-specific and hybrid methods are more *specific* to the individual supplier than the average-data and spend-based methods, they may not produce results that are a more *accurate* reflection of the product's contribution to the reporting company's scope 3 emissions. In fact, data collected from a supplier may actually be less accurate than industry-average data for a particular product. Accuracy derives from the granularity of the emissions data, the reliability of the supplier's data sources, and which, if any, allocation techniques were used. The need to allocate the supplier's emissions to the specific products it sells to the company can add a considerable degree of uncertainty, depending on the allocation methods used (for more information on allocation, see chapter 8 of the *Scope 3 Standard*).

Figure 1.2 provides a decision tree to help companies determine the most appropriate calculation method for estimating their category 1 emissions. Companies may use different calculation methods for different types of purchased goods and services within category 1. For example, they can use more specific methods for categories of goods and services that contribute the most to total emissions. The choice of calculation method depends on several factors outlined in the Introduction, including the company's business goals, the significance (relative to total emissions) of goods and services within category 1, the availability of data, and the quality of available data. See sections 7.3 and 7.4 of the *Scope 3 Standard* for guidance on assessing data quality.

Figure [1.2] Decision tree for selecting a calculation method for emissions from purchased goods and services



Note * Companies should collect data of sufficient quality to ensure that the inventory:

- most appropriately reflects the GHG emissions of the company
- supports the company's business goals for conducting a GHG inventory
- serves the decision-making needs of users, both internal and external to the company.

For more information on how to determine whether data is of sufficient quality, see section 7.3 of the *Scope 3 Standard*

Source: World Resources Institute

Supplier-specific method

Supplier-specific product-level data is the most accurate because it relates to the specific good or service purchased by the reporting company and avoids the need for allocation (see chapter 8 of the *Scope 3 Standard*).

Activity data needed

- Quantities or units of goods or services purchased

Emission factors needed

- Supplier-specific cradle-to-gate emission factors for the purchased goods or services (e.g., if the supplier has conducted a reliable cradle-to-gate GHG inventory, for example, using the GHG Protocol ***Product Standard***).

Data collection guidance

Companies may send questionnaires to each relevant supplier or other value chain partner requesting the following:

- Product life cycle GHG emissions data following the *GHG Protocol Product Standard*
- A description of the methodologies used to quantify emissions and a description of the data sources used (including emission factors and GWP values)
- Whether the data has been assured/verified, and if so, the type of assurance achieved
- Any other relevant information (e.g., percentage of the product inventory calculated using primary data).

Note that to the extent possible, the data provided by the supplier should be for the same time interval as the reporting company's scope 3 inventory and preference should be given to verified data.

When collecting emission factors from suppliers it is recommended that companies also request information relating to the ratio of primary and secondary data used to calculate the emission factor. This information will provide transparency around how much primary data the supplier used to calculate the emission factor for its product. As suppliers become more sophisticated in GHG assessments, the percentage of primary data used to calculate emissions factors for their products is likely to increase. Collecting information on the ratio of primary and secondary data will enable this ratio to be measured and tracked over time.

Calculation formula [1.1] Supplier-specific method

CO_2e emissions for purchased goods or services =

sum across purchased goods or services:

∑ (quantities of good purchased (e.g., kg)

× supplier-specific product emission factor of purchased good or service (e.g., kg CO_2e/kg))

Example [1.1] Calculating emissions from purchased goods and services using the supplier-specific method

Company A is a construction company that purchases materials for its operations. Using its internal IT system, Company A is able to determine the total weight (kg) purchased for each material.

Company A collects product-specific emission factors from the supplier for the purchased goods, which were produced as part of the suppliers' internal GHG inventory reports.

Purchased good	*Supplier*	*Quantities purchased (kg)*	*Supplier-specific emission factor (kg CO_2e/kg)*
Cement	Supplier C	200,000	0.15
Plaster	Supplier D	600,000	0.10
Paint	Supplier E	200,000	0.10
Timber	Supplier F	100,000	0.25
Concrete	Supplier G	50,000	0.20

Note: The activity data and emissions factors are illustrative only, and do not refer to actual data.

Total emissions of purchased goods by Company A is calculated as follows:

∑ (quantities of good purchased (e.g., kg)

× supplier-specific emission factor of purchased good or service (e.g., kg CO_2e/kg))

= (200,000 × 0.15) + (600,000 × 0.1) + (200,000 × 0.1) + (100,000 × 0.25) + (50,000 × 0.2)

= 145,000 kg CO_2e

Hybrid method

Activity data needed

For each supplier, reporting companies should collect as much of the following activity data relating to the good or service purchased as is available (if data is unavailable for certain activities, secondary data can be used to fill the gaps):

- Allocated scope 1 and scope 2 data (including emissions from electricity use and fuel use and any process and fugitive emissions). For guidance on allocating emissions, refer to chapter 8 of the *Scope 3 Standard*
- Mass or volume of material inputs (e.g., bill of materials), mass or volume of fuel inputs used, and distance from the origin of the raw material inputs to the supplier (the transport emissions from the supplier to the reporting company is calculated in category 4 so it should not be included here)
- Quantities of waste output other emissions.

Note that, to the extent possible, the data provided by the supplier should be for the same time interval as the reporting company's scope 3 inventory and preference should be given to assured data.

If it is not feasible for the company to collect data from all its suppliers for all purchased goods, the company may use extrapolation and sampling techniques (see Appendix A).

If a supplier cannot provide data on some or all of the items in the list above, the reporting company may combine the available supplier-specific data with secondary data for the other activities.

Companies should also collect either:

- Mass or number of units of purchased goods or services (e.g., kg, m^3, hours spent, etc.)
- Amount spent on purchased goods or services, by product type, using market values (e.g., dollars).

Emission factors needed

Depending what activity data has been collected from the supplier, companies may need to collect:

- Cradle-to-gate emission factors for materials used by tier 1 supplier to produce purchased goods (Note: these emission factors can either be supplier-specific emission factors provided by the supplier, or industry-average emission factors sourced from a secondary database. In general, preference should be given to more specific and verified emission factors)
- Life cycle emission factors for fuel used by incoming transport of input materials to tier 1 supplier
- Emission factors for waste outputs by tier 1 suppliers to produce purchased goods
- Other emission factors as applicable (e.g., process emissions).

The secondary emission factors required will also depend on what data is available for the purchased good. Companies will need to collect either:

- Cradle-to-gate emission factors of the purchased goods or services per unit of mass or unit of product (e.g., kg CO_2e/kg or kg CO_2e/hour spent)
- Cradle-to-gate emission factors of the purchased goods or services per unit of economic value (e.g., kg CO_2e/$).

Data collection guidance

To combine the primary data collected from the supplier with secondary data (to fill the gaps), the secondary emission factors must be disaggregated so the necessary elements can be overwritten with the supplier-specific data. For example, if a company collects only scope 1, scope 2, and waste data from the supplier, all other upstream emissions need to be estimated using secondary data (see example 1.3 below).

The reporting company may request the following information from suppliers to assist calculation:

- Internal data systems (e.g., bill of materials, freight distance of incoming raw materials)
- Public GHG inventory reports accessible through GHG reporting programs.

Data sources for emission factors include:

- The data sources on the GHG Protocol website (http://www.ghgprotocol.org/Third-Party-Databases). Additional databases may be added periodically, so continue to check the website
- Company- or supplier-developed emission factors (e.g., if the supplier has conducted a reliable cradle-to-gate product GHG inventory or internal LCA report)
- Life cycle databases
- Industry associations
- Government agencies (e.g., Defra provides emission factors for the United Kingdom)
- For activity data, emission factors, and formulas for process and fugitive emissions, see the GHG Protocol website (http://www.ghgprotocol.org/calculation-tools/all-tools) and the IPCC 2006 Guidelines (http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html).

Calculation formula [1.2] Hybrid method (where supplier-specific activity data is available for all activities associated with producing the purchased goods)

CO_2e emissions for purchased goods and services =
sum across purchased goods and services: ∑ scope 1 and scope 2 emissions of tier 1 supplier relating to purchased good or service (kg CO_2e) + **sum across material inputs of the purchased goods and services:** ∑ (mass or quantity of material inputs used by tier 1 supplier relating to purchased good or service (kg or unit) × cradle-to-gate emission factor for the material (kg CO_2e/kg or kg CO_2e/unit)) + **sum across transport of material inputs to tier 1 supplier:** ∑ (distance of transport of material inputs to tier 1 supplier (km) × mass or volume of material input (tonnes or TEUs) × cradle-to-gate emission factor for the vehicle type (kg CO_2e/tonne or TEU/km)) + **sum across waste outputs by tier 1 supplier relating to purchased goods and services:** ∑ (mass of waste from tier 1 supplier relating to the purchased good or service (kg) × emission factor for waste activity (kg CO_2e/kg)) + other emissions emitted in provision of the good or service as applicable

If the supplier is not able to provide specific information about its goods or services sold to the company, it may be necessary to allocate the emissions. For example, to calculate the sum of the waste outputs by the tier 1 supplier that relate to the purchased goods, a company can allocate a proportion of the total waste from the supplier's operations to the purchased product. Guidance on allocation can be found in chapter 8 of the *Scope 3 Standard*.

Example [1.2] Calculating emissions from purchased goods using the hybrid method

Company A prints designs on t-shirts; it purchases the t-shirts from supplier B. Company A obtains the following information about supplier B's scope 1 and scope 2 emissions and waste generated, relating to the t-shirts sold to Company A. Company A also obtains information regarding supplier B's material inputs relating to the t-shirts sold to Company A and transport of these material inputs to supplier B. Company A also collects representative emission factors by reference to life cycle databases.

Scope 1 and scope 2 data from supplier B relating to production of purchased goods

	Amount (kWh)	*Emission factor (kg CO_2e/kWh)*
Electricity	5,000	0.5
Natural gas	2,500	0.2

Example [1.2] Calculating emissions from purchased goods using the hybrid method (continued)

Material inputs of purchased goods

	Mass purchased (kg)	*Emission factor (kg CO_2e/kg)*
Cotton	5,000	7.0
Polymer	2,500	5.0
Chemical A	500	2.0
Chemical B	500	1.5

Transport of material inputs to supplier B

	Distance of transport (km)	*Vehicle type emission factor (kg CO_2e/kg/km)*
Cotton	1,000	0.01
Polymer	2,500	0.02
Chemical A	800	0.05
Chemical B	200	0.10

Waste outputs by supplier B relating to production of purchased goods

	Amount (kg)	*Emission factor (kg CO_2e/kg of waste sent to landfill)*
Waste sent to landfill	100	0.5

Note: The activity data and emissions factors are illustrative only, and do not refer to actual data.

Example [1.2] Calculating emissions from purchased goods using the hybrid method (continued)

Emissions at each stage are calculated by multiplying activity data by respective emission factors, as follows:

scope 1 and scope 2 emissions by supplier B:

∑ scope 1 and scope 2 emissions of supplier B relating to purchased good (kg CO_2e)
= (5,000 × 0.5) + (2,500 × 0.2)
= 3,000 kg CO_2e

material input emissions:

∑ (mass or value of material inputs used by supplier B relating to purchased good (kg or $)
× emission factor for the material (kg CO_2e/kg or kg CO_2e/$))
= (5,000 × 7) + (2,500 × 5) + (500 × 2) + (500 × 1.5)
= 49,250 kg CO_2e

transport of material inputs emissions:

∑ (distance of transport of material inputs to supplier B (km) × mass of material input (kg)
× emission factor for the vehicle type (kg CO_2e/kg/km))
= (5,000 × 1,000 × 0.01) + (2,500 × 2,500 × 0.02) + (500 × 800 × 0.05) + (500 × 200 × 0.1)
= 20,500 kg CO_2e

waste output by supplier B:

∑ (mass of waste from supplier B relating to the purchased good (sent to landfill) (kg)
× emission factor for waste to landfill (kg CO_2e/kg))
= 100 × 0.5
= 50 kg CO_2e

total emissions of purchased t-shirts from supplier B is calculated by summing the above results, as follows:

3,000 + 49,250 + 20,500 + 50
= 72,800 kg CO_2e

If the reporting company decides that it is not within the company's business goals to collect all the data needed to calculate emissions based entirely on supplier-specific activity data, the reporting company may choose to use a combination of supplier-specific and average data. This option may be desirable in cases where supplier engagement is part of a company's business goals for carrying out a scope 3 inventory, but where collecting all the data necessary to calculate a cradle-to-gate emission factor from supplier-specific activity data is not practical. It is likely that many suppliers will not be able to provide all the activity data listed, so this technique of combining some supplier-specific data with secondary data is a possible alternative.

Calculation formula 1.3 follows the same structure as calculation formula 1.2. The difference is that where data is unavailable for certain activities, secondary data (either process data or EEIO data) is used to fill the gaps. (See also figure 1.1.).

Calculation formula 1.3 shows an example in which only scope 1 and scope 2 data and waste data were collected from the supplier, however, any combination of data could be collected from suppliers and the remaining data estimated using secondary data in the same way.

Calculation formula [1.3] Hybrid method (where only allocated scope 1 and scope 2 emissions and waste data are available from supplier)

CO_2e emissions for a purchased good where the supplier can only provide scope 1 and scope 2 emissions data and waste generated in operations data =

sum across purchased goods and services:

∑ scope 1 and scope 2 emissions of tier 1 supplier relating to purchased good or service (kg CO_2e)

+

∑ (mass of waste from tier 1 supplier relating to the purchased good (kg)
× emission factor for waste activity (kg CO_2e/kg))

+

∑ (mass or quantity of units of purchased good or service (kg)
× emission factor of purchased good excluding scope 1, scope 2, and emissions from waste generated by producer (kg CO_2e/kg or unit or $))

Example [1.3] Calculating emissions from a purchased good by using the hybrid method (where only allocated scope 1 and scope 2 emissions and waste data are available from supplier)

Using the same example, company A prints designs on t-shirts; it purchases the t-shirts from supplier B. However, in this case, supplier B only has data available on allocated scope 1 and scope 2 emissions and waste generated in supplier B's operations (emissions and waste were allocated using physical allocation based on the total output of t-shirts in the reporting year and the quantity of t-shirts sold to Company A). Company A has to estimate the upstream emissions of supplier B using secondary data. Company A collects data on the quantity of t-shirts purchased from supplier B, as well as a cradle-to-gate emission factor for the production of a t-shirt (by reference to life cycle databases).

Scope 1 and scope 2 data from supplier B relating to production of purchased goods

	Amount (kWh)	*Emission factor (kg CO_2e/kWh)*
Electricity	5,000	0.5
Natural gas	2,500	0.2

Waste outputs by supplier B relating to production of purchased goods

	Amount (kg)	*Emission factor (kg CO2e/kg of waste sent to landfill)*
Waste sent to landfill	100	0.5

Example [1.3] Calculating emissions from a purchased good by using the hybrid method (where only allocated scope 1 and scope 2 emissions and waste data are available from supplier) (continued)

Quantity of t-shirts purchased from supplier B and cradle-to-gate emission factor from life cycle database. The cradle-to-gate process emission factor is from a database where it is possible to disaggregate the stages of the life cycle of the t-shirt. Emissions associated with the manufacture stage were excluded as these represent the emissions of supplier B itself (as opposed to cotton farming, processing, etc., which occur further upstream).

	Number of t-shirts purchased from supplier B	*Cradle-to-gate process emission factor (kg CO2e/per t-shirt)*	*Cradle-to-gate process emission factor (kg CO2e/per t-shirt) (excluding scope 1 and 2 emissions and emissions from waste associated with final producer)*
T-shirts	12,000	6	5.6

Note: The activity data and emissions factors are illustrative only, and do not refer to actual data.

Emissions at each stage are calculated by multiplying activity data by respective emission factors, as follows:

scope 1 and scope 2 emissions from supplier B:

∑ scope 1 and scope 2 emissions of supplier B relating to purchased good (kg CO_2e)

= (5,000 × 0.5) + (2,500 × 0.2)

= 3,000 kg CO_2e

waste output from supplier B:

∑ (mass of waste from supplier B relating to the purchased good (sent to landfill) (kg)

× emission factor for waste to landfill (kg CO2e/kg))

= 100 × 0.5

= 50 kg CO_2e

all other upstream emissions from supplier B:

∑ (mass or quantity of units of purchased good or service (kg)

× emission factor of purchased good excluding scope 1 and scope 2 emissions of producer (kg CO2e/kg or unit or $))

= (50,000 × 5.6)

= 67,200 kg CO_2e

total emissions of purchased t-shirts from supplier B is calculated by summing the above results, as follows:

= 3,000 + 50 + 67,200

= 70,250 kg CO_2e

Average-data method

In this method, the company collects data on the mass or other relevant units of purchased goods or services and multiplies them by relevant secondary (e.g., industry average) cradle-to-gate emission factors. Secondary emission factors may be found in process-based life cycle inventory databases. Refer to "Secondary data sources" in the Introduction for further guidance on these databases.

Activity data needed

- Mass or number of units of purchased goods or services for a given year (e.g., kg, hours spent).

Companies may organize the above data more efficiently by differentiating purchased goods or services into mass and other categories of units (e.g., volume), where appropriate.

Emission factors needed

- Cradle-to-gate emission factors of the purchased goods or services per unit of mass or unit of product (e.g., kg CO_2e/kg or kg CO_2e/hour spent).

Data collection guidance

Data sources for activity data include:

- Internal data systems (e.g., bill of materials)
- Purchasing records.

Data sources for emission factors include:

- Process life cycle databases
- Industry associations.

Companies should assess both the age of the database (i.e., temporal representativeness) and the geographic relevance to the supplier's location (e.g., geographical representativeness), as well as the technological representatives, completeness, and reliability of the data. For additional guidance, see sections 7.3 and 7.5 of the *Scope 3 Standard*.

Calculation formula [1.4] Average-data method

CO_2e emissions for purchased goods or services =

sum across purchased goods or services:

∑ (mass of purchased good or service (kg)

× emission factor of purchased good or service per unit of mass (kg CO_2e/kg))

or

∑ (unit of purchased good or service (e.g., piece)

× emission factor of purchased good or service per reference unit (e.g., kg CO_2e/piece))

Spend-based method

If the supplier-specific method, hybrid method, and average-data method are not feasible (e.g., due to data limitations), companies should apply the average spend-based method by collecting data on the economic value of purchased goods and services and multiplying them by the relevant EEIO emission factors. Refer to the "Secondary data sources" in the Introduction for further guidance on EEIO data.

Companies may use a combination of the material-based method and spend-based method by using both process-based and EEIO data for various purchased goods and services.

Activity data needed

- Amount spent on purchased goods or services, by product type, using market values (e.g., dollars)
- Where applicable, inflation data to convert market values between the year of the EEIO emissions factors and the year of the activity data.

Emission factors needed

- Cradle-to-gate emission factors of the purchased goods or services per unit of economic value (e.g., kg CO_2e/$).

Data collection guidance

Data sources for activity data include:

- Internal data systems (e.g., enterprise resource planning (ERP) systems)
- Bill of materials
- Purchasing records.

Data sources for emission factors include:

- Environmentally-extended input-output (EEIO) databases
- Industry associations.

Calculation formula [1.5] Spend-based method

CO_2e emissions for purchased goods or services =

sum across purchased goods or services:

∑ (value of purchased good or service ($)

× emission factor of purchased good or service per unit of economic value (kg CO_2e/$))

Example [1.4] Calculating emissions from purchased goods and services by using a combination of the average-data method and the spend-based method

Company E purchases over 1,000 components and raw materials to manufacture a broad range of electronic goods. Instead of obtaining data from all suppliers and allocating emissions between 1,000 separate goods, the company groups purchased goods based on:

- Semi-processed components (e.g., average semiconductor)
- Raw materials (e.g., average steel).

Physical data (mass) is available only for the semi-processed components. For raw materials, only spend data is available.

Company E calculates the mass of semi-processed components by combining primary data available through its IT systems with extrapolation techniques. For raw materials, the company determines the amount spent through its enterprise resource planning (ERP) system. Company E obtains process-based cradle-to-gate emission factors for the semi-processed components and EEIO cradle-to-gate emission factors for the raw materials.

The results of the data collection are summarized below:

Purchased semi-processed components	*Mass (kg)*	*Emission factor (kg CO2e/kg)*
Hard drive	400	20
Integrated circuits	200	10
Liquid Crystal Display (LCD)	500	40
Semiconductors	100	70
Battery	1,500	3
Keyboard	300	3

Example [1.4] Calculating emissions from purchased goods and services by using a combination of the average-data method and the spend-based method (continued)

Purchased raw materials	*Value ($)*	*Emission factor (kg CO2e/$)*
Plastic (PS)	5,000	0.3
Plastic (ABS)	3,000	0.3
PET (film)	4,000	0.3
Aluminum	6,000	0.5
Steel	1,500	0.2
Cyclohexane	5,000	0.2
Epoxy resin	5,000	0.3
Copper	1,000	0.3
Glass	5,000	0.4

Note: the activity data and emissions factors are illustrative only, and do not refer to actual data.

Total emissions of purchased goods by Company E can be calculated by multiplying the mass/value purchased by the respective emission factors and summing the results, as follows:

$$= (400 \times 20) + (200 \times 10) + (500 \times 40) + (100 \times 70) + (1{,}500 \times 3) + (300 \times 3) + (5{,}000 \times 0.3)$$
$$+ (3{,}000 \times 0.3) + (4{,}000 \times 0.3) + (6{,}000 \times 0.5) + (1{,}500 \times 0.2) + (5{,}000 \times 0.2)$$
$$+ (5{,}000 \times 0.3) + (1{,}000 \times 0.3) + (5{,}000 \times 0.4)$$

$$= 54{,}100 \text{ kg } CO_2e$$

2

Category 2: Capital Goods

Category description

This category includes all upstream (i.e., cradle-to-gate) emissions from the production of capital goods purchased or acquired by the reporting company in the reporting year. Emissions from the use of capital goods by the reporting company are accounted for in either scope 1 (e.g., for fuel use) or scope 2 (e.g., for electricity use), rather than in scope 3.

Capital goods are final products that have an extended life and are used by the company to manufacture a product; provide a service; or sell, store, and deliver merchandise. In financial accounting, capital goods are treated as fixed assets or as plant, property, and equipment (PP&E). Examples of capital goods include equipment, machinery, buildings, facilities, and vehicles.

In certain cases, there may be ambiguity over whether a particular purchased product is a capital good (to be reported in category 2) or a purchased good (to be reported in category 1). Companies should follow their own financial accounting procedures to determine whether to account for a purchased product as a capital good in this category or as a purchased good or service in category 1. Companies should not double count emissions between category 1 and category 2. See box 2.1 for accounting for emissions from capital goods.

Box [2.1] Accounting for emissions from capital goods

In financial accounting, capital goods (sometimes called "capital assets") are typically depreciated or amortized over the life of the asset. For purposes of accounting for scope 3 emissions, companies should not depreciate, discount, or amortize the emissions from the production of capital goods over time. Instead companies should account for the total cradle-to-gate emissions of purchased capital goods in the year of acquisition, the same way the company accounts for emissions from other purchased products in category 1. If major capital purchases occur only once every few years, scope 3 emissions from capital goods may fluctuate significantly from year to year. Companies should provide appropriate context in the public report (e.g., by highlighting exceptional or non-recurring capital investments).

Source: Box 5.4 from the *Scope 3 Standard*

Calculating emissions from capital goods

Companies may use the following methods to calculate scope 3 emissions from capital goods:

- **Supplier-specific method**, which involves collecting product-level cradle-to-gate GHG inventory data from goods suppliers
- **Hybrid method**, which involves a combination of supplier-specific activity data (as available) and using secondary data to fill the gaps. This method involves:
  - collecting allocated scope 1 and scope 2 emissions from suppliers
  - calculating upstream emissions of goods by collecting available data from suppliers on the amount of materials, fuel, electricity used, distance transported, and waste generated from the production of goods and applying appropriate emission factors
  - using secondary data to calculate upstream emissions wherever supplier-specific data is not available.
- **Average-product method**, which involves estimating emissions for goods by collecting data on the mass or other relevant units of goods purchased and multiplying by relevant secondary (e.g., industry average) emission factors (e.g., average emissions per unit of good)
- **Average spend-based method**, which involves estimating emissions for goods by collecting data on the economic value of goods purchased and multiplying by relevant secondary (e.g., industry average) emission factors (e.g., average emissions per monetary value of goods).

The calculation methods for category 1 (Purchased goods and services) and category 2 (Capital goods) are the same. For guidance on calculating emissions from category 2 (Capital goods), refer to the guidance in the previous section for category 1 (Purchased goods and services).

3

Category 3: Fuel- and Energy-Related Activities Not Included in Scope 1 or Scope 2

Category description

This category includes emissions related to the production of fuels and energy purchased and consumed by the reporting company in the reporting year that are not included in scope 1 or scope 2.

Category 3 excludes emissions from the combustion of fuels or electricity consumed by the reporting company because they are already included in scope 1 or scope 2. Scope 1 includes emissions from the combustion of fuels by sources owned or controlled by the reporting company. Scope 2 includes the emissions from the combustion of fuels to generate electricity, steam, heating, and cooling purchased and consumed by the reporting company.

This category includes emissions from four activities (see table 3.1).

Table [3.1] Activities included in category 3 (Fuel- and energy-related emissions not included in scope 1 or scope 2)

Activity	*Description*	*Applicability*
A. Upstream emissions of purchased fuels	Extraction, production, and transportation of fuels consumed by the reporting company Examples include mining of coal, refining of gasoline, transmission and distribution of natural gas, production of biofuels, etc.	Applicable to end users of fuels
B. Upstream emissions of purchased electricity	Extraction, production, and transportation of fuels consumed in the generation of electricity, steam, heating, and cooling that is consumed by the reporting company Examples include mining of coal, refining of fuels, extraction of natural gas, etc.	Applicable to end users of electricity, steam, heating, and cooling
C. Transmission and distribution (T&D) losses	Generation (upstream activities and combustion) of electricity, steam, heating, and cooling that is consumed (i.e., lost) in a T&D system – reported by end user	Applicable to end users of electricity, steam, heating, and cooling
D. Generation of purchased electricity that is sold to end users	Generation (upstream activities and combustion) of electricity, steam, heating, and cooling that is purchased by the reporting company and sold to end users – reported by utility company or energy retailer Note: This activity is particularly relevant for utility companies that purchase wholesale electricity supplied by independent power producers for resale to their customers.	Applicable to utility companies and energy retailers*

Source: Table 5.5 from the Scope 3 Standard.

Note: * Energy retailers include any company selling excess power to the grid.

Table 3.2 explains how each company accounts for GHG emissions. In this example, the emission factor of the electricity sold by Company B is 1 tonne (t) CO_2e/MWh. All numbers are illustrative only.

Table [3.2] Accounting for emissions across an electricity value chain

Reporting company	*Scope 1*	*Scope 2*	*Scope 3*
Coal mining, processing, and transport (Company A)	5 t CO_2e	0 t CO_2e (unless electricity is used during coal mining and processing)	100 t CO_2e from the combustion of sold products (i.e., coal) *Reported in category 11 (Use of sold products)*
Power generator (Company B)	100 t CO_2e	0 t CO_2e	5 t CO_2e from the extraction, production, and transportation of fuel (i.e., coal) consumed by the reporting company *Reported in Category 3 (Fuel- and energy-related activities not included in scope 1 or scope 2)* Note: The generator does not account for scope 3 emissions associated with sold electricity because the emissions are already accounted for in scope 1.
Utility (Company C)	0 (unless SF_6 is released from the T&D system)	10 t CO_2e from the generation of electricity purchased and consumed by Company C	0.5 t CO_2e from the extraction, production, and transportation of fuels (i.e., coal) consumed in the generation of electricity consumed by Company C (5 tons from coal mining x 10 percent of electricity generated by B that is consumed by C) 94.5 t CO_2e from the generation (life cycle, i.e., upstream activities and combustion) of electricity purchased by Company C and sold to Company D *Both are reported in category 3 (Fuel- and energy-related activities not included in scope 1 or scope 2)*
End consumer of electricity (Company D)	0	90 t CO_2e from the generation of electricity purchased and consumed by Company D	4.5 t CO_2e from the extraction, production, and transportation of coal consumed in the generation of electricity consumed by Company D 10.5 t CO_2e from the generation (life cycle, i.e., upstream activities and combustion) of electricity that is consumed (i.e., lost) in transmission and distribution *Both are reported in category 3 (Fuel- and energy-related activities not included in scope 1 or scope 2)*

Source: Table 5.6 from the Scope 3 Standard.

Calculating upstream emissions of purchased fuels (activity A of table 3.1)

This activity includes the extraction, production, and transportation of fuels consumed by the reporting company. Companies may use either of the following methods to calculate scope 3 emissions from upstream emissions of purchased fuels:

- **Supplier-specific method**, which involves collecting data from fuel providers on upstream emissions (extraction, production and transportation) of fuel consumed by the reporting company
- **Average-data method**, which involves estimating emissions by using secondary (e.g., industry average) emission factors for upstream emissions per unit of consumption (e.g., kg CO_2e/kWh).

Activity data needed

Companies should collect data on:

- Quantities and types of fuel consumed.

Emission factors needed

To calculate emissions from this activity, companies should use life cycle emission factors that exclude emissions from combustion, since emissions from combustion are accounted for in scope 1 (in the case of fossil fuels) or in a separate memo item (in the case of direct CO_2 emissions from combustion of biomass or biofuels).

If using the supplier-specific method, companies should use fuel-provider-specific emission factors for extraction, production, and transportation of fuels per unit of fuel consumed (e.g., kg CO_2e/kWh), by fuel type and country/region.

If using the average-data method, companies should use average emission factors for upstream emissions per unit of consumption (e.g., kg CO_2e/kWh).

Data collection guidance

Companies may obtain data by:

- Reference to their scope 1 GHG inventory, including quantities, sources and types of fuels consumed
- Collecting data from their fuel procurement departments
- If necessary, collecting data from fuel suppliers
- Reference to life cycle databases.

A list of third-party databases is on the GHG Protocol website (http://www.ghgprotocol.org/Third-Party-Databases). Additional databases may be added periodically, so continue to check the website.

Some sources of emission factors may provide upstream emissions of purchased fuels, excluding emissions from combustion. If this is not the case, companies should determine upstream emissions from purchased fuels (excluding emissions from combustion) using the following formula.

Calculation formula [3.1] Upstream emissions of purchased fuels

Upstream CO_2e emissions of purchased fuels (extraction, production, and transportation of fuels consumed by the reporting company) =

sum across each fuel type consumed:

∑ (fuel consumed (e.g., kWh) × upstream fuel emission factor (kg CO_2e)/kWh))

where:

upstream fuel emission factor = life cycle emission factor – combustion emission factor.

If possible, the combustion and life cycle emission factors should be from the same temporal, technical, and geographic representativeness (see table 7.6 of the *Scope 3 Standard*).

Calculating upstream emissions of purchased electricity (activity B of table 3.1)

This activity includes the extraction, production, and transportation of fuels consumed in the generation of electricity, steam, heating, and cooling that is consumed by the reporting company. Companies may use either of the following methods to calculate scope 3 emissions from upstream emissions of purchased electricity:

- **Supplier-specific method**, which involves collecting data from electricity providers on upstream emissions (extraction, production, and transportation) of electricity consumed by the reporting company
- **Average-data method**, which involves estimating emissions by using secondary (e.g., industry average) emission factors for upstream emissions per unit of consumption (e.g., kg CO_2e/kWh).

Activity data needed

Companies should collect data on:

- Total quantities of electricity, steam, heating, and cooling purchased and consumed per unit of consumption (e.g., MWh), broken down by supplier, grid region, or country.

Emission factors needed

To calculate emissions from this activity, companies should use life cycle emission factors that exclude emissions from combustion, since emissions from combustion are accounted for in scope 2 (in the case of electricity).

Companies should select an emission factor using one of the following approaches:

Supplier-specific method

- Utility-specific emission factors for extraction, production and transportation of fuels consumed per MWh of electricity, steam, heating, or cooling generated.

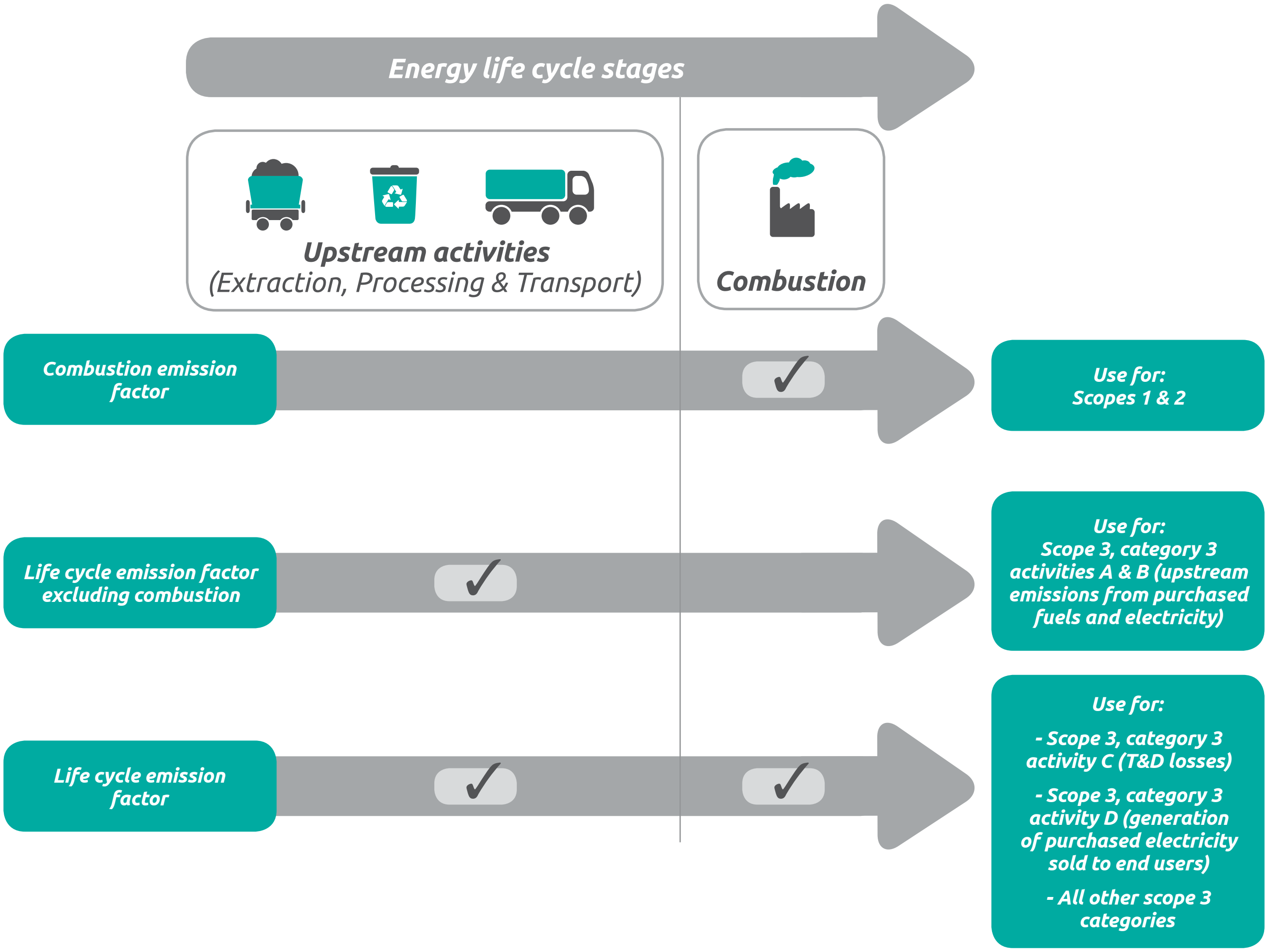
If data for the above is not available or applicable, companies should use the following approach:

Average-data method

- Grid-region, country, or regional emission factors for extraction, production, and transportation of fuels per unit of consumption (e.g., kg CO_2e/kWh) of electricity, steam, heating, or cooling generated.

Companies should ensure that emission factors used to calculate upstream emissions of purchased electricity do not include emissions from combustion because emissions from combustion to generate electricity are accounted for in scope 2 (see figure 3.1).

Figure [3.1] Energy emission factors to use for different activities within scope 3 category 3



Data collection guidance

Companies should disaggregate the total amount of electricity, steam, heating, or cooling purchased, by characteristics such as supplier, grid region, or country. Energy consumption data should then be multiplied by representative emission factors (e.g., supplier or grid region) to calculate emissions.

Data sources for activity data include:

- Reference to their scope 2 GHG inventories, including quantity and sources of electricity, steam, heat, and cooling consumption and the grid mix where the electricity was consumed
- National statistics published by government agencies
- Government agency energy management departments
- If necessary, energy suppliers or generators.

Data sources for emission factors include:

- Supplier developed emission factors for life cycle of fuels
- Life cycle databases – excluding emissions from fuel combusted to generate electricity and transmission and distribution (T&D) losses.

The combustion and life cycle emission factors should be from the same temporal, technical, and geographic representativeness (see table 7.6 of the *Scope 3 Standard*).

Scope 2 includes emissions from the generation of purchased electricity, steam, heating, and cooling consumed by the reporting company. In some regions, electricity emission factors include life cycle activities related to electricity, such as transmission and distribution of electricity, or extraction, processing and transportation of fuels used to generate electricity. Non-generation activities related to electricity are accounted for in scope 3, category 3 (Fuel- and energy-related activities not included in scope 1 or scope 2), rather than in scope 2. As a result, companies should seek (and emission factor developers should provide) transparent, disaggregated electricity emission factors that allow separate accounting of emissions from electricity generation in scope 2 and non-generation activities related to electricity in scope 3. Proper accounting creates consistency in scope 2 accounting and reporting among companies and avoids double counting of the same emission within scope 2 by more than one company. See figure 7.2 in the *Scope 3 Standard* for more information on different types of electricity emission factors.

Calculation formula [3.2] Upstream emissions of purchased electricity

Upstream CO_2e emissions of purchased electricity
(Extraction, production, and transportation of fuels consumed in the generation of electricity, steam, heating, and cooling that is consumed by the reporting company) =

sum across suppliers, regions, or countries:

∑ (electricity consumed (kWh) × upstream electricity emission factor (kgCO_2e)/kWh))
+ (steam consumed (kWh) × upstream steam emission factor (kg CO_2e)/kWh))
+ (heating consumed (kWh) × upstream heating emission factor (kg CO_2e)/kWh))
+ (cooling consumed (kWh) × upstream cooling emission factor (kg CO_2e)/kWh))

where:

upstream emission factor = life cycle emission factor – combustion emissions factor – T&D losses

Note: T&D losses need to be subtracted only if they are included in the life cycle emission factor.
Companies should check the emission factor to establish whether or not T&D losses have been taken into account.

Calculating emissions from transmission and distribution losses (activity C in table 3.1)

This activity includes the lifecycle emissions of electricity, steam, heating, and cooling that is consumed (i.e., lost) in a transmission and distribution (T&D) system.

Companies may use the following methods to calculate scope 3 emissions from T&D losses:

- **Supplier-specific method**, which involves collecting data from electricity providers on T&D loss rates of grids where electricity is consumed by the reporting company
- **Average-data method**, which involves estimating emissions by using average T&D loss rates (e.g., national, regional, or global averages, depending on data availability).

Activity data needed

Companies should collect data on:

- Electricity, steam, heating, and cooling per unit of consumption (e.g., MWh), broken down by grid region or country.

Emission factors needed

Companies should collect combustion emission factors for electricity, steam, heating, and cooling, and also use the approaches below to collect data on T&D loss rates.

Supplier-specific method

- Utility-specific T&D loss rate (percent), specific to the grid where energy is generated and consumed.

If data for the above is not available or applicable, the following approach should be used:

Average-data method

- Country average T&D loss rate (percent)
- Regional average T&D loss rate (percent)
- Global average T&D loss rate (percent)

Data Collection Guidance

A World Bank database provides T&D loss rates by country (http://data.worldbank.org/indicator/EG.ELC.LOSS.ZS?order=wbapi_data_value_2009+wbapi_data_value+wbapi_data_value-last&sort=desc).

Calculation formula [3.3] Transmission and distribution losses

CO_2e emissions from energy (generation of electricity, steam, heating, and cooling that is consumed (i.e., lost) in a T&D system) =

sum across suppliers, regions, or countries:

∑ (electricity consumed (kWh) × electricity life cycle emission factor ((kg CO2e)/kWh) × T&D loss rate (%))

+ (steam consumed (kWh) × steam life cycle emission factor ((kg CO2e)/kWh) × T&D loss rate (%))

+ (heating consumed (kWh) × heating life cycle emission factor ((kg CO2e)/kWh) × T&D loss rate (%))

+ (cooling consumed (kWh) × cooling life cycle emission factor ((kg CO2e)/kWh) × T&D loss rate (%))

Example [3.1] Calculating upstream emissions of purchased electricity

Company A operates data center services in 10 countries. It purchases electricity, and in some countries, district heating, to run its data centers (district heating is a centrally operated heating system that services entire cities or other large areas). It is able to collect primary data on all electricity purchased through an energy tracking system, and uses an average-data method for relevant emission factors.

Note that this is an example for category 3 as a whole. As Company A does not sell purchased electricity, it does not have any emissions associated with category 3 activity D (life cycle emissions of power that is purchased and sold).

Country	Electricity purchased (kWh)	District heating purchased (kWh)
Australia	500,000	N/A
Canada	600,000	50,000
India	400,000	N/A
United States	5,500,000	N/A
Turkey	200,000	N/A

Note: the activity data are illustrative only, and do not refer to actual data.

Company A sources emission factors for extraction-, production-, and transportation-related emissions of fuels for producing electricity/heating, as well as T&D losses:

Country	Upstream emission factor of purchased electricity (kg CO2e/kWh)	Electricity/heat combustion emission factor (kg CO2e/kWh)	T&D loss rate (percent)	Upstream emission factor of purchased heating (kg CO2e/kWh)
Australia	0.12	0.8 (electricity)	10 (electricity)	N/A
Canada	0.10	0.4 (electricity) 0.15 (heat)	13 (electricity) 5 (heat)	0.05
India	0.15	0.8 (electricity)	15 (electricity)	N/A
United States	0.10	0.5 (electricity)	10 (electricity)	N/A
Turkey	0.05	0.4 (electricity)	12 (electricity)	N/A

Note: the emissions factors are illustrative only, and do not refer to actual data.

Example [3.1] Calculating upstream emissions of purchased electricity (continued)

upstream emissions from purchased electricity (category 3, activity B):

= (500,000 × 0.12) + (600,000 × 0.1) + (400,000 × 0.15) + (5,500,000 × 0.1) + (200,000 × 0.05)

= 740,000 kg CO_2e

life cycle emissions from transmission and distribution losses (category 3, activity C):

= (500,000 × 0.8 × 0.1) + (600,000 × 0.4 × 0.13) + (50,000 × 0.15 × 0.05) + (400,000 × 0.8 × 0.15) + (5,500,000 × 0.5 × 0.1) + (200,000 × 0.4 × 0.12)

= 404,175 kg CO_2e

upstream emissions from purchased heating (category 3, activity B):

= 50,000 × 0.05

= 2,500 kg CO_2e

total emissions from upstream purchased electricity and heat including transmission and distribution losses is calculated as follows:

= 740,000 + 404,175 + 2,500

= 1,146,675 kg CO_2e

Calculating life cycle emissions from power that is purchased and sold (activity D in table 3.1)

This activity includes the generation of electricity, steam, heating, and cooling that is purchased by the reporting company and sold to end users (reported by a utility company or energy retailer).

Companies may use the following methods to calculate scope 3 emissions from power that is purchased and sold:

- **Supplier-specific method**, which involves collecting emissions data from power generators
- **Average-data method**, which involves estimating emissions by using grid average emission rates.

Activity data needed

Companies should collect data on:

- Quantities and specific source (e.g., generation unit) of electricity purchased and re-sold.

Emission factors needed

Companies should collect data using one of the following approaches:

Supplier-specific method

- Specific CO_2, CH_4, and N_2O emissions data for generation units from which purchased power is produced.

If data for the above is not available or applicable, the following approach may be used.

Average-data method

- Grid average emission factor for the origin of purchased power.

Calculation formula [3.4] Emissions from power that is purchased and sold

CO_2e emissions from power that is purchased and sold (generation of electricity, steam, heating, and cooling that is purchased by the reporting company and sold to end users (reported by utility company or energy retailer)) =

sum across suppliers, regions or countries:

∑ (electricity purchased for resale (kWh) × electricity life cycle emission factor (kg CO_2e)/kWh))
+ (steam purchased for resale (kWh) × steam life cycle emission factor (kg CO_2e)/kWh))
+ (heating purchased for resale (kWh) × heating life cycle emission factor (kg CO_2e)/kWh))
+ (cooling purchased for resale (kWh) × cooling life cycle emission factor (kg CO_2e)/kWh))

4

Category 4: Upstream Transportation and Distribution

Category description

Category 4 includes emissions from:

- Transportation and distribution of products purchased in the reporting year, between a company's tier 1 suppliers[3] and its own operations in vehicles not owned or operated by the reporting company (including multi-modal shipping where multiple carriers are involved in the delivery of a product, but excluding fuel and energy products)
- Third-party transportation and distribution services purchased by the reporting company in the reporting year (either directly or through an intermediary), including inbound logistics, outbound logistics (e.g., of sold products), and third-party transportation and distribution between a company's own facilities.

Emissions may arise from the following transportation and distribution activities throughout the value chain:

- Air transport
- Rail transport
- Road transport
- Marine transport
- Storage of purchased products in warehouses, distribution centers, and retail facilities.

Outbound logistics services purchased by the reporting company are categorized as upstream because they are a purchased service. Emissions from transportation and distribution of purchased products upstream of the reporting company's tier 1 suppliers (e.g., transportation between a company's tier 2 and tier 1 suppliers) are accounted for in scope 3, category 1 (Purchased goods and services). Table 4.1 shows the scope and category of emissions where each type of transportation and distribution activity should be accounted for.

3 Tier 1 suppliers are companies with which the reporting company has a purchase order for goods or services (e.g., materials, parts, components, etc.). Tier 2 suppliers are companies with which tier 1 suppliers have a purchase order for goods and services (see figure 7.3 in the Scope 3 Standard).

A reporting company's scope 3 emissions from upstream transportation and distribution include the scope 1 and scope 2 emissions of third-party transportation companies (allocated to the reporting company).

Table [4.1] Accounting for emissions from transportation and distribution activities in the value chain

Transportation and distribution activity in the value chain	*Scope and category of emissions*
Transportation and distribution in vehicles and facilities owned or controlled by the reporting company	Scope 1 (for fuel use) or scope 2 (for electricity use)
Transportation and distribution in vehicles and facilities leased by and operated by the reporting company (and not already included in scope 1 or scope 2)	Scope 3, category 8 (Upstream leased assets)
Transportation and distribution of purchased products, upstream of the reporting company's tier 1 suppliers (e.g., transportation between a company's tier 2 and tier 1 suppliers)	Scope 3, category 1 (Purchased goods and services), since emissions from transportation are already included in the cradle-to-gate emissions of purchased products. These emissions are not required to be reported separately from category 1.
Production of vehicles (e.g., ships, trucks, planes) purchased or acquired by the reporting company	Account for the upstream (i.e., cradle-to-gate) emissions associated with manufacturing vehicles in Scope 3, category 2 (Capital goods)
Transportation of fuels and energy consumed by the reporting company	Scope 3, category 3 (Fuel- and energy-related emissions not included in scope 1 or scope 2)
Transportation and distribution of products purchased by the reporting company, between a company's tier 1 suppliers and its own operations (in vehicles and facilities not owned or controlled by the reporting company)	Scope 3, category 4 (Upstream transportation and distribution)
Transportation and distribution services purchased by the reporting company in the reporting year (either directly or through an intermediary), including inbound logistics, outbound logistics (e.g., of sold products), and transportation and distribution between a company's own facilities (in vehicles and facilities not owned or controlled by the reporting company)	Scope 3, category 9 (Downstream transportation and distribution)

Source: Table 5.7 from the *Scope 3 Standard.*

This section provides calculation guidance first from transportation and then from distribution (e.g., warehouses, distribution centers).

Calculating emissions from transportation

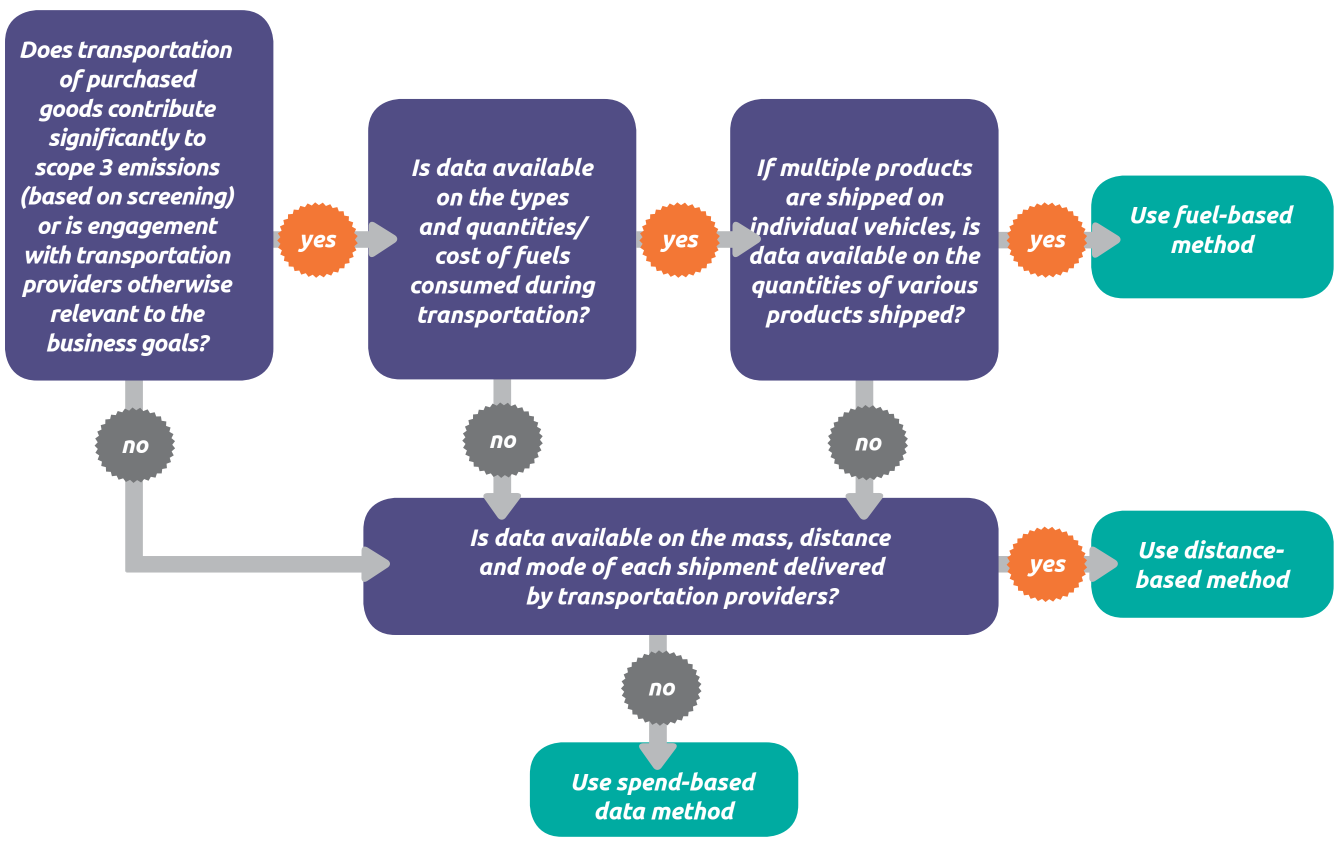
Companies may use the following methods to calculate scope 3 emissions from transportation:

- **Fuel-based method**, which involves determining the amount of fuel consumed (i.e., scope 1 and scope 2 emissions of transport providers) and applying the appropriate emission factor for that fuel
- **Distance-based method,** which involves determining the mass, distance, and mode of each shipment, then applying the appropriate mass-distance emission factor for the vehicle used
- **Spend-based method,** which involves determining the amount of money spent on each mode of business travel transport and applying secondary (EEIO) emission factors.

The GHG Protocol has a calculation tool for transportation that uses a combination of the fuel-based and distance-based methods. This combination is used because CO_2 is better estimated from fuel use, and CH_4 and N_2O are better estimated from distance travelled. The tool uses fuel-efficiency ratios to convert either type of activity data (fuel or distance) supplied by the user into either fuel or distance depending on the GHG being calculated. The calculation tool ("GHG emissions from transport or mobile sources") is available at the GHG Protocol website: http://www.ghgprotocol.org/calculation-tools/all-tools).

It is important to note that the calculation tool was originally developed to calculate an organization's scope 1 emissions (i.e., emissions from vehicles that the organization owns and operates). Therefore, the emission factors that pre-populate the calculation tool are combustion emission factors. When calculating emissions from transportation in scope 3, companies should use life cycle emission factors (see "Energy emission factors in scope 3 accounting" in the Introduction for more information on which emission factors to use). If using the GHG Protocol transport calculation tool to calculate scope 3 emissions, companies should customize the tool by entering life cycle emission factors.

Figure [4.1] Decision tree for selecting a calculation method for emissions from upstream transportation



Fuel-based method (transportation)

The fuel-based method should be used when companies can obtain data for fuel use from transport providers (and, if applicable, refrigerant leakage due to refrigeration of products) from vehicle fleets (e.g., trucks, trains, planes, vessels). Companies should also take into account any additional energy used and account for fugitive emissions (e.g., refrigerant loss or air-conditioning). Companies may optionally calculate any emissions from unladen backhaul (i.e., the return journey of the empty vehicle).

Where fuel use data is unavailable, the company may derive fuel use by using the:

- Amount spent on fuels and the average price of fuels
- Distance travelled and the vehicle's fuel efficiency
- Amount spent on transportation services, fuel cost share (as percent of total cost of transportation services) and the average price of fuels.

For calculating CO_2, the fuel-based method is more accurate than the distance-based method because fuel consumption is directly related to emissions.

The fuel-based method is best applied if the vehicle exclusively ships the reporting company's purchased goods (i.e., exclusive use or truckload shipping, rather than less-than-truckload (LTL) shipping). Otherwise, emissions should be allocated between goods shipped for the reporting company and goods shipped for other companies. See chapter 8 of the *Scope 3 Standard* for further guidance on allocating emissions.

Companies should allocate emissions based on the following default limiting factors for each transportation mode, unless more accurate data is available to show that another factor is the limiting factor:

- **Road transport:** Truck capacity is typically limited by mass, so mass-based allocation should be used
- **Marine transport**: Vessel capacity is typically limited by volume, so volume-based allocation should be used
- **Air transport**: Aircraft capacity is typically limited by mass, so mass-based allocation should be used
- **Rail transport**: Rail capacity is typically limited by mass, so mass-based allocation should be used.

If there are multiple shipments on a transport leg, distance should also be used as a means for allocation. (For more information, see the Deutsche Post DHL example in this section.)

If data required for allocation is not available or reliable due to the variety of goods transported in one vehicle at the same time, the distance-based method should be used to calculate scope 3 emissions.

Activity data needed

Companies should collect data on:

- Quantities of fuel (e.g., diesel, gasoline, jet fuel, biofuels) consumed
- Amount spent on fuels
- Quantities of fugitive emissions (e.g., from air conditioning and refrigeration).

If applicable:

- Distance travelled
- Average fuel efficiency of the vehicle, expressed in units of liters of fuel consumed per tonne per kilometer transported
- Cost of fuels
- Volume and/or mass of purchased goods in the vehicle
- Information on whether the products are refrigerated in transport.

Emission factors needed

Companies should collect:

- Fuel emission factors, expressed in units of emissions per unit of energy consumed (e.g., kg CO_2e/liters, CO_2e/Btu)
- For electric vehicles (if applicable), electricity emission factors, expressed in units of emissions per unit of electricity consumed (e.g., kg CO_2e/kWh)
- Fugitive emission factors, expressed in units of emissions per unit (e.g., kg CO_2e/kg refrigerant leakage)

Emission factors should at a minimum include emissions from fuel combustion, and should, where possible, include cradle-to-gate emissions of the fuel (i.e., from extraction, processing, and transportation to the point of use).

Note: For air travel emission factors, multipliers or other corrections to account for radiative forcing may be applied to the GWP of emissions arising from aircraft transport. If applied, companies should disclose the specific factor used.

Data collection guidance

Data sources for activity data include:

- Aggregated fuel receipts
- Purchase records (provided by transportation providers)
- Internal transport management systems.

Data sources for emission factors include:

- Transportation carriers
- Government agencies (e.g., Defra provides emission factors for the United Kingdom)
- The GHG Protocol website (http://www.ghgprotocol.org/calculation-tools/all-tools and http://www.ghgprotocol.org/standards/scope-3-standard)
- Industry associations
- Additional sources in table 4.2.

Transportation emissions are calculated by multiplying each fuel/refrigerant type used by a corresponding emission factor and summing the results as shown in the formula below:

Calculation formula [4.1] Fuel-based method (transportation)

CO_2e emissions from transportation =

sum across fuel types:

∑ (quantity of fuel consumed (liters) × emission factor for the fuel (e.g., kg CO_2e/liter))

+

sum across grid regions:

∑ (quantity of electricity consumed (kWh) × emission factor for electricity grid (e.g., kg CO_2e/kWh))

+

sum across refrigerant and air-conditioning types:

∑ (quantity of refrigerant leakage × global warming potential for the refrigerant (e.g., kg CO_2e))

If fuel consumption data is unavailable, companies may use formula 4.2 and/or formula 4.3 to calculate quantities of fuel consumed.

Calculation formula [4.2] Calculating fuel use from fuel spend

Quantities of fuel consumed (liters) =

sum across fuel types:

$$\sum \left(\frac{\text{total fuel spend (e.g., \$)}}{\text{average fuel price (e.g., \$/liter)}} \right)$$

Companies should first apportion annual amount spent on fuel to each relevant fuel type. Where the mix of fuels is unknown, companies may refer to average fuel mix statistics from industry bodies and/or government statistical publications.

Calculation formula [4.3] Calculating fuel use from distance travelled

Quantities of fuel consumed (liters) =

sum across transport steps:

∑ (total distance travelled (e.g., km) × fuel efficiency of vehicle (e.g., liters/km))

If allocation is needed, companies should calculate the allocated fuel use (for the goods shipped by the reporting company) using the formula below, then apply formula 4.1 above.

Calculation formula [4.4] Allocating fuel use

Allocated fuel use =

$$= \text{total fuel consumed (liters)} \times \left(\frac{\text{mass/volume of company's goods}}{\text{mass/volume of goods transported}} \right)$$

Companies may optionally substitute mass of goods by volume with dimensional mass or chargeable mass where data is available to prove that the alternative method is more suitable.

Dimensional mass is a calculated mass that takes into account packaging volume as well as the actual mass of the goods.

Chargeable mass is the higher value of either the actual or the dimensional mass of the goods.

Companies may optionally calculate emissions from unladen backhaul (i.e., the return journey of the empty vehicle) using the following formula:

Calculation formula [4.5] Calculating emissions from unladen backhaul

CO_2e emissions from unladen backhaul =

for each fuel type:

∑ (quantity of fuel consumed from backhaul × emission factor for the fuel (e.g., kg CO_2e/liter))

where:

quantity of fuel consumed from backhaul

= average efficiency of vehicles unladed (l/km) × total distance travelled unladen.

Example [4.1] Calculating emissions from upstream transportation using the fuel-based method

Company A makes bread in Italy. Suppliers B, C, and D supply refrigerated raw materials for Company A's operations. Company A collects activity data from its suppliers on the amount of fuel used and refrigerant leakage incurred by the transport of raw materials to Company A's facility. All trucks transport goods exclusively for Company A. Company A collects emission factors for the fuel type used by suppliers and for refrigerant leakage.

The situation is summarized in the table below:

Supplier	*Fuel consumed (liters) or refrigerant leakage (kg)*	*Fuel/refrigerant type*	*Emission factor (kg CO2e/ liter for fuels; Global warming potential for refrigerants)*
B	50,000	Diesel	3
C	80,000	Diesel	3
D	90,000	Diesel	3
D	50	Refrigerant R410a	2,000

Note: The activity data and emissions factors are illustrative only, and do not represent actual data.

emissions from diesel is calculated as:

∑ (quantity of fuel consumed (liters) × emission factor for the fuel (kg CO_2e/liter))

= (50,000 × 3) + (80,000 × 3) + (90,000 × 3) = 660,000 kg CO2e

emissions from refrigerant leakage is calculated as:

∑ (quantity of refrigerant leakage (kg) × emission factor for refrigerant (kg CO_2e/kg))

= 50 × 2,000 = 100,000 kg CO_2e

total emissions is calculated as follows:

emissions from fuels + emissions from refrigerant leakage

= 660,000 + 100,000 = 760,000 kg CO_2e

Distance-based method (transportation)

In this method, distance is multiplied by mass or volume of goods transported and relevant emission factors that incorporate average fuel consumption, average utilization, average size and mass or volume of the goods and the vehicles, and their associated GHG emissions.

Emission factors for this method are typically represented in grams or kilograms of carbon dioxide equivalent per tonne-kilometer or TEU-kilometer. Tonne-kilometer is a unit of measure representing one tonne of goods transported over 1 kilometer. TEU-kilometer is a unit of measure representing one twenty-foot container equivalent of goods transported over 1 kilometer.

The distance-based method is especially useful for an organization that does not have access to fuel or mileage records from the transport vehicles, or has shipments smaller than those that would consume an entire vehicle or vessel.

If sub-contractor fuel data cannot be easily obtained in order to use the fuel-based method, then the distance-based method should be used. Distance can be tracked using internal management systems or, if these are unavailable, online maps. However, accuracy is generally lower than the fuel-based method as assumptions are made about the average fuel consumption, mass or volume of goods, and loading of vehicles.

Activity data needed

Companies should collect data on the distance travelled by transportation suppliers. This data may be obtained by:

- Mass or volume of the products sold
- Actual distances provided by transportation supplier (if actual distance is unavailable, companies may use the shortest theoretical distance)
- Online maps or calculators
- Published port-to-port travel distances.

The actual distances should be used when available, and each leg of the transportation supply chain should be collected separately.

Emission factors needed

Companies should collect:

- Emission factor by mode of transport (e.g., rail, air, road) or vehicle types (e.g., articulated lorry, container vessel), expressed in units of greenhouse gas (CO_2, CH_4, N_2O, or CO_2e) per unit of mass (e.g., tonne) or volume (e.g., TEU) travelled (e.g., kilometer).

Common forms of emission factors are kg CO_2e/tonne/km for road transport or kg CO_2e/TEU/km for sea transport.

Note: For air travel emission factors, multipliers or other corrections to account for radiative forcing may be applied to the GWP of emissions arising from aircraft transport. If applied, companies should disclose the specific factor used.

Data collection guidance

Companies may obtain activity data from:

- Purchase orders
- Specific carrier or mode operator
- Internal management systems
- Industry associations
- Online maps and calculators.

Companies may obtain emission factors from:

- Transportation carriers
- Government agencies (e.g., Defra provides emission factors for the United Kingdom)
- The GHG Protocol website (http://www.ghgprotocol.org/calculation-tools/all-tools and http://www.ghgprotocol.org/standards/scope-3-standard)
- Industry associations
- Additional sources in table 4.2.

When collecting emission factors, it is important to note that they may be vehicle, regional, or country specific.

Calculation resources include:

- GHG Protocol Calculation Tool, "Mobile Combustion GHG Emissions Calculation Tool. Version 2.0. June 2009," developed by World Resources Institute, available at http://www.ghgprotocol.org/calculation-tools/all-tools.
- U.S. EPA Climate Leaders GHG Inventory Protocol, "Optional Emissions from Commuting, Business Travel and Product Transport," available at: http://www.epa.gov/stateply/documents/resources/commute_travel_product.pdf
- UK Defra, "Guidance on Measuring and Reporting GHG Emissions from Freight Transport Operations," available at http://www.defra.gov.uk/environment/economy/business-efficiency/reporting/
- UK Defra GHG Conversion Factors, developed by the United Kingdom Department of Environment, Food and Rural Affairs (Defra), available at http://www.defra.gov.uk/environment/economy/business-efficiency/reporting/

Table [4.2] Data collection guidance for the distance-based method

Mode	Vehicle	Unit	Primary data sources	Secondary data sources	Comments	Assumptions
air	Freighter short-haul	kg CO_2e/t-km	Carrier	ICAO UK Defra Environmental reports of air carriers LCA databases EEIO databases	Carrier can provide a) shipment specific emissions b) trade-line emissions based on existing network design and historical plane consumption c) emissions per type of plane	
	Freighter long- haul	kg CO_2e/t-km				
	Belly-freight short-haul	kg CO_2e/t-km				
	Belly-freight long-haul	kg CO_2e/t-km				
	Passenger plane short-haul	kg CO_2e/t-km				
	Passenger plane long-haul	kg CO_2e/t-km				
Ship	Container vessel <2000 TEU	kg CO_2e/TEU-km	Carrier	IMO CCWG LCA databases EEIO databases	Carrier can provide a) shipment specific emissions b) trade-line emissions based on existing network design and historical vessel consumption c) emissions per type of vessel	Default 1 TEU = 10 t
	Container vessel 2000-5000 TEU	kg CO_2e/TEU-km				
	Container vessel 5000-8000 TEU	kg CO_2e/TEU-km				
	Container vessel >8000TEU	kg CO_2e/TEU-km				
	Bulk vessel <20000 dwt	kg CO_2e/t-km				
	Bulk vessel >20000 dwt	kg CO_2e/t-km				

Table [4.2] Data collection guidance for the distance-based method (continued)

Mode	*Vehicle*	*Unit*	*Primary data sources*	*Secondary data sources*	*Comments*	*Assumptions*
Rail	Electric	kg CO_2e/t-km	Operator	EcoTransIT LCA databases EEIO databases	Operator can provide shipment specific emissions on trade-line historical emissions	
	Diesel	kg CO_2e/t-km				
Truck	Van <3.5t	kg CO_2e/t-km	Operator	EcoTransIT NTM TREMOVE (EU) EPA Smart Way (US) Handbook Emission Factors for Road Transport (HBEFA) LCA databases EEIO databases	Trucker can provide a) shipment specific emissions b) trade-line emissions based on existing network design and historical fleet consumption c) emissions per type of truck	Default 1 TEU = 10 t
	Truck 3.5-7.5t	kg CO_2e/t-km				
	Truck 7.5t-16t	kg CO_2e/t-km				
	Truck 16t-32t single axle	kg CO_2e/t-km kg CO_2e/TEU-km				
	Truck >32t tractor and trailer or flatbed	kg CO_2e/t-km kg CO_2e/TEU-km				
Warehouse	Dry warehouse	kg CO_2e/pallet-day kg CO_2e/TEU-day kg CO_2e/cbm-day kg CO_2e/kg-day	Operator	LCA databases EEIO databases	Operator may also have the emission factor based on the warehouse surface	1 pallet = 1 square meter of floor space
	Refrigerated warehouse	kg CO_2e/pallet-day kg CO_2e/TEU-day kg CO_2e/cbm-day kg CO_2e/kg-day				
Terminal	Terminal	kg CO_2 e/t kg CO_2e/TEU	Terminal owner	LCA databases EEIO databases		1 TEU = 10 t

Source: Carbon Trust

Notes:

ICAO = International Civil Aviation Organization

IMO = International Maritime Organization

CCWG = Clean Cargo Working Group

TEU = twenty-foot equivalent units, a measure of the size of shipping containers. One standard-size container is 1 TEU.

To calculate emissions, companies should multiply the quantity of goods purchased in mass (including packaging and pallets) or volume by the distance travelled in the transport leg and then multiply that by an emission factor specific to the transport leg (usually a transport mode- or vehicle type- specific emission factor).

Because each transport mode or vehicle type has a different emission factor, the transport legs should be calculated separately and total emissions aggregated.

The following formula can be applied to all modes of transport and/or vehicle types to calculate emissions from transportation:

Calculation formula [4.6] Distance-based method (transportation)

CO_2e emissions from transportation =

sum across transport modes and/or vehicle types:

= ∑ (mass of goods purchased (tonnes or volume) × distance travelled in transport leg (km)
× emission factor of transport mode or vehicle type (kg CO_2e/tonne or volume/km))

Example [4.2] Calculating emissions from upstream transportation using the distance-based method

Company A makes chairs and sources basic materials from Suppliers B, C, and D. Company A calculates total distance from the transport of the basic goods and obtains information from suppliers on vehicle type used for transport. Company A obtains relevant emission factors from lifecycle databases. The information is summarized below:

Supplier	*Mass of transported goods (tonnes)*	*Distance transported (km)*	*Transport mode or vehicle type*	*Emission factor (kg CO_2e/TEU-km)*
B	2	2,000	Truck (rigid, >3.5-7.5t)	0.2
C	1	3,000	Air (long haul)	1.0
D	6	4,000	Container 2,000–2,999 TEU	0.05

Note: the activity data and emission factors in this example are for illustrative purposes only.

Emissions from road transport:

= ∑ (mass of goods purchased (tonnes) × distance travelled in transport leg × emission factor of transport mode or vehicle type (kg CO_2e/tonne-km))

= 2 × 2,000 × 0.2

= 800 kg CO_2e

emissions from air transport:

= ∑ (quantity of goods purchased (tonnes) x distance travelled in transport leg x emission factor of transport mode or vehicle type (kg CO_2e/tonne-km))

= 1 × 3,000 × 1

= 3,000 kg CO_2e

emissions from sea transport:

= ∑ (quantity of goods purchased (tonnes) x distance travelled in transport leg x emission factor of transport mode or vehicle type (kg CO_2e/tonne-km))

= 6 × 4,000 × 0.05

= 1,200 kg CO_2e

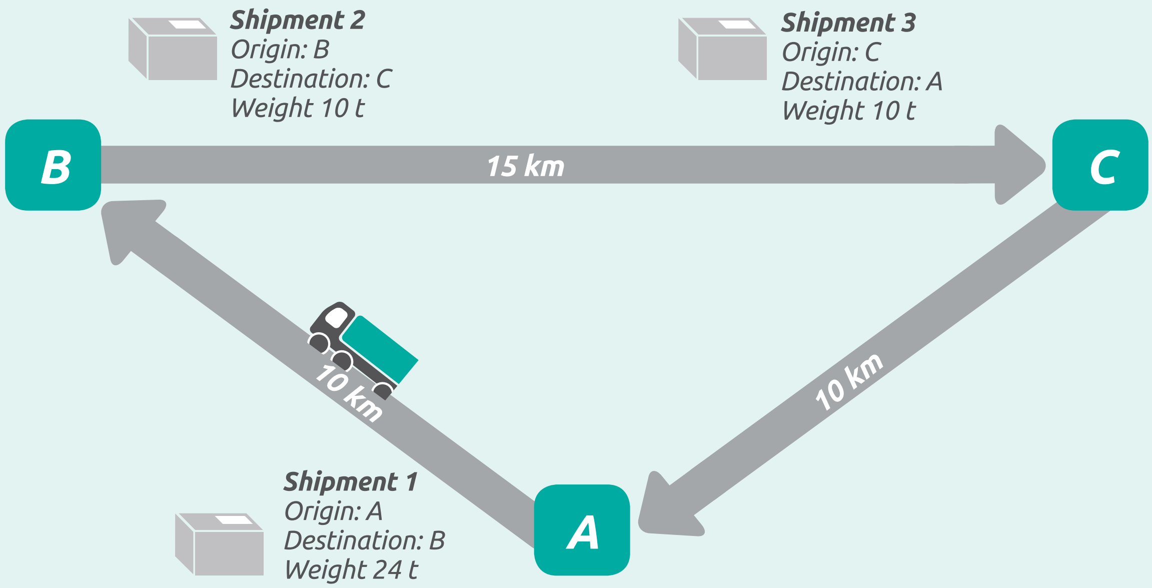
total emissions form transport (upstream) is calculated as:

= emissions from road transport + emissions from air transport + emissions from sea transport

= 800 + 3,000 + 1,200

= 5,000 kg CO_2e

Example [4.3] Allocating emissions from transportation (Deutsche Post DHL)



Deutsche Post DHL, a global mail and logistics company, set a CO_2 efficiency target. The choice of appropriate allocation factors is a critical decision point to ensure fair allocation of emissions. The following example demonstrates a typical situation, in which different allocation factors may lead to completely different results.

This example is about a typical delivery run where a truck needs to stop at different locations to pick up or drop off shipments. In this example, 24-tonne shipment 1 needs to be transported from a home station (A) to a customer (B). At customer (B), shipment 1 is unloaded and shipments 2 and 3 are picked up. Shipment 2 is addressed to customer (C) and shipment 3 needs to be transported back to the home station (A).

Data were not available on the type and quantity of fuel consumed during transportation, but data on the mass, distance, and mode of shipment was available. Therefore the distance-based method was used. It was calculated that 31.5 kg CO_2 was emitted during this delivery run. How can we allocate these emissions to the shipments?

I. Allocation using driven-tonne kilometers

One option for allocation is to use driven-tonne kilometers (tkm) as an allocation factor. For calculating the tonne-kilometers, the weight of each shipment is multiplied by the distance driven. Then the total amount of CO_2 emissions is allocated to the shipments on the basis of their share in the driven tonne- kilometers.

	Shipment 1	Shipment 2	Shipment 3	Total
Driven tkm	240 tkm	150 tkm	250 tkm	640 tkm
Total emissions				31.5 kg CO_2
Allocation factor				0.049 kg CO_2 per tkm
Shipment emissions	11.8 kg CO_2	7.4 kg CO_2	12.3 kg CO_2	31.5 kg CO_2

Example [4.3] Allocating emissions from transportation (Deutsche Post DHL) (continued)

Surprisingly, shipment 2, which causes the longest transportation leg (15 km), receives minimum emissions and shipment 3 is “punished” for being transported jointly with shipment 2 via customer (C). The next option shows how such downsides can be mitigated.

II. Allocation using shortest theoretical distance

The second option aims at allocating CO_2 emissions using the shortest theoretical distance between the origin and destination of each shipment (also known as the Great Circle Distance) as an allocation factor. The shipments’ CO_2 allocation is independent from the actual driven distance because that is of no relevance to the customer. As in the example above, tonne-kilometers are calculated – this time using the shortest theoretical distance between a shipment’s origin and destination – before performing the allocation.

	Shipment 1	*Shipment 2*	*Shipment 3*	*Total*
Tkm based on GCD	240 tkm	150 tkm	100 tkm	490 tkm
Total emissions				31.5 kg CO_2
Allocation factor				0.064 kg CO_2 per tkm
Shipment emissions	15.43 kg CO_2	9.64 kg CO_2	6.43 kg CO_2	31.5 kg CO_2

Because the allocation of emissions for individual items is based only on the characteristics of the individual shipments, this option provides a fair allocation method.

Although there are many more options to perform the allocation to shipments in freight transport, this example illustrates pitfalls a user can encounter by picking an allocation factor.

Spend-based method

If the fuel-based method and distance method cannot be applied (e.g., due to data limitations), companies should apply the spend-based method to calculate the emissions from transportation. In this method, the amount spent on transportation by type is multiplied by the relevant EEIO emission factors. Refer to "Environmentally-extended input output (EEIO) data" in the Introduction for guidance on EEIO data. Companies may determine the amount spent on transportation through bills, invoice payments, or financial accounting systems. The spend-based method is effective for screening purposes; however it has high levels of uncertainty and the fuel-based and distance-based methods are recommended for accounting for transportation emissions.

Activity data needed

- Amount spent on transportation by type (e.g. road, rail, air, barge), using market values (e.g., dollars).

Emission factors needed

- Cradle-to-gate emission factors of the transportation type per unit of economic value (e.g., kg CO_2e/$)
- Where applicable, inflation data to convert market values between the year of the EEIO emissions factors and the year of the activity data.

Data collection guidance

Data sources for activity data include:

- Internal data systems (e.g., financial accounting systems)
- Bills
- Invoices.

Data sources for emission factors include:

- Environmentally-extended input-output (EEIO) databases. A list of EEIO databases is provided on the GHG Protocol website (http://www.ghgprotocol.org/Third-Party-Databases). Additional databases may be added periodically, so continue to check the website.

Calculation formula [4.7] Spend-based method (transportation)

CO_2e emissions from transportation =

sum across transport modes and/or vehicle types:

∑ (amount spent on transportation by type ($)

× relevant EEIO emission factors per unit of economic value (kg CO_2e/$))

Example [4.4] Calculating emissions from transportation by using the spend-based method

Company A makes televisions and sources basic materials from suppliers B, C, and D. Company A calculates total amount spent from the transport of the basic goods and obtains information from suppliers on vehicle type used for transport. Company A obtains relevant emission factors from EEIO databases. The information is summarized in the table below:

Supplier	*Amount spent ($)*	*Transport mode or vehicle type*	*EEIO emission factor (kg CO_2e/$)*
B	20,000	Truck (rigid, >3.5-7.5t)	0.04
C	30,000	Air (long haul)	0.15
D	40,000	Container 2,000–2,999 TEU	0.05

Note: the activity data and emission factors in this example are for illustrative purposes only.

emissions from road transport:
= ∑ (amount spent on transportation leg
× EEIO emission factor of transport mode or vehicle type (kg CO_2e/$))
= 20,000 × 0.04 = 800 kg CO_2e/$

emissions from air transport:
= ∑ (amount spent on transportation leg × EEIO emission factor of
transport mode or vehicle type (kg CO_2e/$))
= 30,000 × 0.15 = 4,500 kg CO_2e/$

emissions from sea transport:
= ∑ (amount spent on transport leg
× EEIO emission factor of transport mode or vehicle type (kg CO_2e/$))
= 40,000 × 0.05 = 2,000 kg CO_2e/$

total emissions from transport (upstream) is calculated as:
= emissions from road transport + emissions from air transport + emissions from sea transport
= 800 + 4,500 + 2,000 = 7,300 kg CO_2e/$

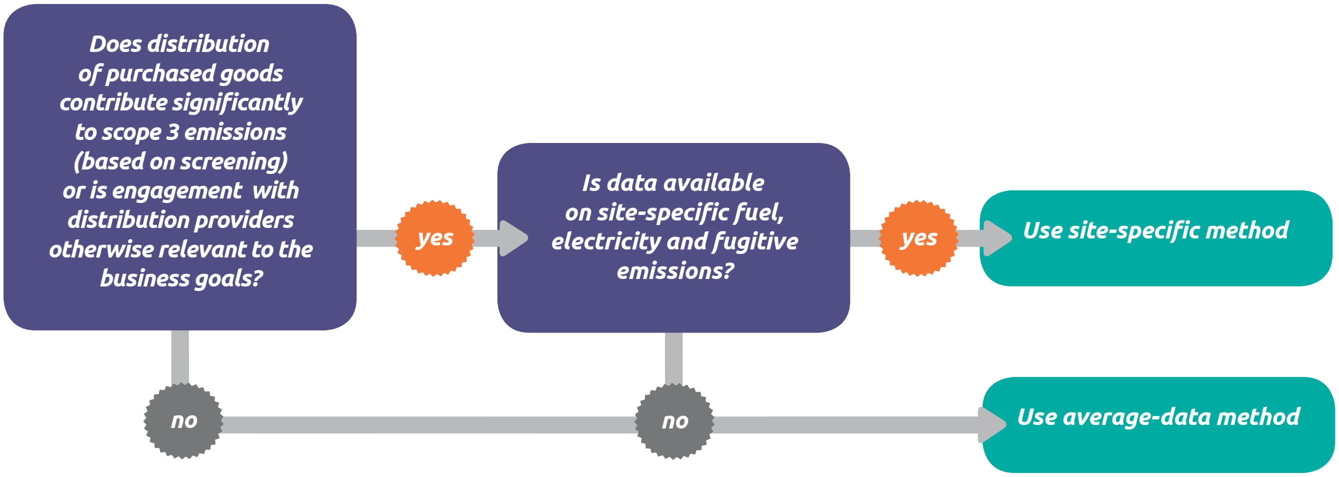
Calculating emissions from distribution (upstream)

Companies may use either of two methods to calculate scope 3 emissions from upstream distribution (e.g. storage facilities):

- **Site-specific method,** which involves site-specific fuel, electricity, and fugitive emissions data and applying the appropriate emission factors
- **Average-data method**, which involves estimating emissions for each distribution activity, based on average data (such as average emissions per pallet or cubic meter stored per day).

Figure 4.2 gives a decision tree for selecting a calculation method for emissions from upstream distribution.

Figure [4.2] Decision tree for selecting a calculation method for emissions from upstream distribution



Site-specific method

This method involves collecting site-specific fuel and energy data from the storage facility (e.g., warehouses, distribution centres) of individual distribution activities, and multiplying them by appropriate emission factors.

If the storage facility stores goods for companies other than the reporting company, emissions should be allocated to the reporting company. For more information on allocation, see chapter 8 of the *Scope 3 Standard*.

Activity data needed

Companies should collect data on:

- Site-specific fuel and electricity use
- Site-specific fugitive emissions (e.g., air conditioning or refrigerant leakage)
- The average occupancy rate of the storage facility (i.e., average total volume of goods stored).

Emission factors needed

Companies should collect:

- Site or regionally specific emission factors for energy sources (e.g., electricity and fuels) per unit of consumption (e.g., kg CO2e/kWh for electricity, kg CO2e/liter for diesel)
- Emission factors of fugitive and process emissions (kg CO_2e/kg).

Data collection guidance

Data sources for activity data include:

- Utility bills
- Purchase records
- Meter readings
- Internal IT systems.

Data sources for emission factors include:

- Life cycle databases
- Company-developed emission factors
- Industry associations.

Calculation formula [4.8] Site-specific method (distribution)

CO_2e emissions from distribution =

for each storage facility:

emissions of storage facility (kg CO_2e)
= (fuel consumed (kWh) × fuel emission factor (kg CO_2e/kWh))
+ (electricity consumed (kWh) × electricity emission factor (kg CO_2e)/kWh)
+ (refrigerant leakage (kg) × refrigerant emission factor (kg CO_2e)/kg))

then, allocate emissions based on volume that company's products take within storage facility:

$$\text{allocated emissions of storage facility} = \left(\frac{\text{volume of reporting company's purchased goods (m}^3\text{)}}{\text{total volume of goods in storage facility (m}^3\text{)}}\right)$$

$$\times \text{ emissions of storage facility (kg } CO_2e\text{)}$$

finally, sum across all storage facilities:
∑ allocated emissions of storage facility

If data are available, companies may optionally allocate emissions based on different storage methods (e.g., temperature-controlled storage and ambient storage). This allocation step can be significant within shared storage. Companies may optionally allocate emissions based on length of time goods spend in storage.

If a company has a large number of distribution channels, sampling may be appropriate (see Appendix A for more information).

Example [4.5] Calculating emissions from upstream distribution using the site-specific method

Company A's products are stored at two facilities throughout the reporting year. No chilling or freezing is needed during storage. Company A collects the data from operators on the amount of fuel and electricity consumed for the reporting year, as well as the volume of company A's purchased goods compared to total volume of goods. Company A collects corresponding emission factors from life cycle databases.

The information is summarized in the table below:

Storage facility	Electricity consumed (kWh)	Electricity emission factor (kg CO_2e/kWh)	Natural gas used (kWh)	Natural gas emission factor (kg CO_2e/kWh)	Volume of company A's goods (m^3)	Total volume of goods in storage facility (m^3)
1	10,000	0.8	1,000	0.25	100	400
2	15,000	0.8	2,000	0.25	200	800

Note: the activity data and emissions factors are illustrative only, and do not refer to actual data.

emissions from storage facility 1 are calculated as:

$$((\text{fuel consumed (kWh)} \times \text{fuel emission factor (kg } CO_2\text{e)/kWh)}) + (\text{electricity consumed (kWh)} \times \text{electricity emission factor (kg } CO_2\text{e)/kWh)}) \times \left(\frac{\text{volume of reporting company's purchased goods (m}^3\text{)}}{\text{(total volume of goods in storage facility (m}^3\text{)}}\right)$$

$$= ((10{,}000\times0.8)+(1{,}000\times0.25))\times(100/400)$$

$$= 2{,}062.5 \text{ kg } CO_2\text{e}$$

emissions from storage facility 2 are calculated as:

$$((\text{fuel consumed (kWh)} \times \text{fuel emission factor (kg } CO_2\text{e)/kWh)}) + (\text{electricity consumed (kWh)} \times \text{electricity emission factor (kg } CO_2\text{e)/kWh)}) \times \left(\frac{\text{volume of reporting company's purchased goods (m}^3\text{)}}{\text{(total volume of goods in storage facility (m}^3\text{)}}\right)$$

$$= (15{,}000 \times 0.8) + (2{,}000 \times 0.25)) \times (200 / 800)$$

$$= 3{,}125 \text{ kg } CO_2\text{e}$$

total emissions from distribution (upstream) is calculated as follows:

emissions from storage facility 1 + emissions from storage facilities 2

$$= 2{,}062.5 + 3{,}125 = 5{,}187.5 \text{ kg } CO_2\text{e}$$

Average-data method

Companies should use the average-data method where supply-chain specific data is unavailable. Companies should collect average emission factors for distribution activities.

Activity data needed

Companies should collect data based on throughput:

- Volume of purchased goods that are stored (e.g., square meters, cubic meters, pallet, TEU) or number of pallets needed to store purchased goods
- Average number of days that goods are stored.

Emission factors needed

Companies should collect data that allows the calculation of emissions per unit, per time period stored. This can be expressed in several different ways, including:

- Emission factor per pallet per day stored in facility
- Emission factor per square meter or cubic meter per day stored in facility
- Emission factor per TEU (twenty-foot equivalent unit) stored in facility.

Data collection guidance

Data sources for activity data include:

- Supplier records
- Internal management systems.

Data sources for emission factors include:

- Life cycle databases
- Supplier- or company-developed emission factors
- Industry associations (for example the U.S. Energy information Administration has developed a dataset on average energy use by building type. Commercial Buildings Energy Consumption Survey, at http://www.eia.doe.gov/emeu/cbecs/)
- Academic publications.

Calculation formula [4.9] Average-data method (distribution)

CO_2e emissions from distribution =

sum across storage facilities:

∑ (volume of stored goods (m^3 or pallet or TEU) × average number of days stored (days) × emission factor for storage facility (kg CO_2e/m^3 or pallet or TEU/day))

Example [4.6] Calculating emissions from upstream distribution using the average-data method

Company A is a producer of pasta. Its products are stored at distribution centers and then sent for retail sale in supermarkets. Company A collects data on the total volume needed to store its goods at storage facilities and the average number of days its goods are stored. Emission factors are collected from an academic publication. The information is summarized in the table:

Storage facility types	*Total volume of stored goods (m^3)*	*Average days stored*	*Emission factor of storage (kg $CO_2e/m^3/day$)*
Distribution center	4,000	2	0.01
Supermarkets	4,000	2	0.02

Note: the activity data and emission factors in this example are for illustrative purposes only.

the emissions can be calculated as follows:

$$\sum (\text{volume stored goods } (m^3) \times \text{number of days stored (days)} \times \text{emission factor for storage facility } (\text{kg } CO_2e/m^3/\text{day}))$$

$$= (4{,}000 \times 2 \times 0.01) + (4{,}000 \times 2 \times 0.02) = 80 + 160 = 240 \text{ kg } CO_2e$$

5

Category 5: Waste Generated in Operations

Category description

Category 5 includes emissions from third-party disposal and treatment of waste generated in the reporting company's owned or controlled operations in the reporting year. This category includes emissions from disposal of both solid waste and wastewater.

Only waste treatment in facilities owned or operated by third parties is included in scope 3. Waste treatment at facilities owned or controlled by the reporting company is accounted for in scope 1 and scope 2. Treatment of waste generated in operations is categorized as an upstream scope 3 category because waste management services are purchased by the reporting company.

This category includes all future emissions that result from waste generated in the reporting year. (See chapter 5.4 of the *Scope 3 Standard* for more information on the time boundary of scope 3 categories.)

Waste treatment activities may include:

- Disposal in a landfill
- Disposal in a landfill with landfill-gas-to-energy (LFGTE) – that is, combustion of landfill gas to generate electricity
- Recovery for recycling
- Incineration
- Composting
- Waste-to-energy (WTE) or energy-from-waste (EfW) – that is, combustion of municipal solid waste (MSW) to generate electricity
- Wastewater treatment.

A reporting company's scope 3 emissions from waste generated in operations derive from the scope 1 and scope 2 emissions of solid waste and wastewater management companies. Companies may optionally include emissions from transportation of waste in vehicles operated by a third party.

Calculating emissions from waste generated in operations

Different types of waste generate different types and quantities of greenhouse gases. Depending on the type of waste, the following greenhouse gases may be generated:

- CO_2 (from degradation of both fossil and biogenic carbon contained in waste)
- CH_4 (principally from decomposition of biogenic materials in landfill or WTE technologies)
- HFCs (from the disposal of refrigeration and air conditioning units).

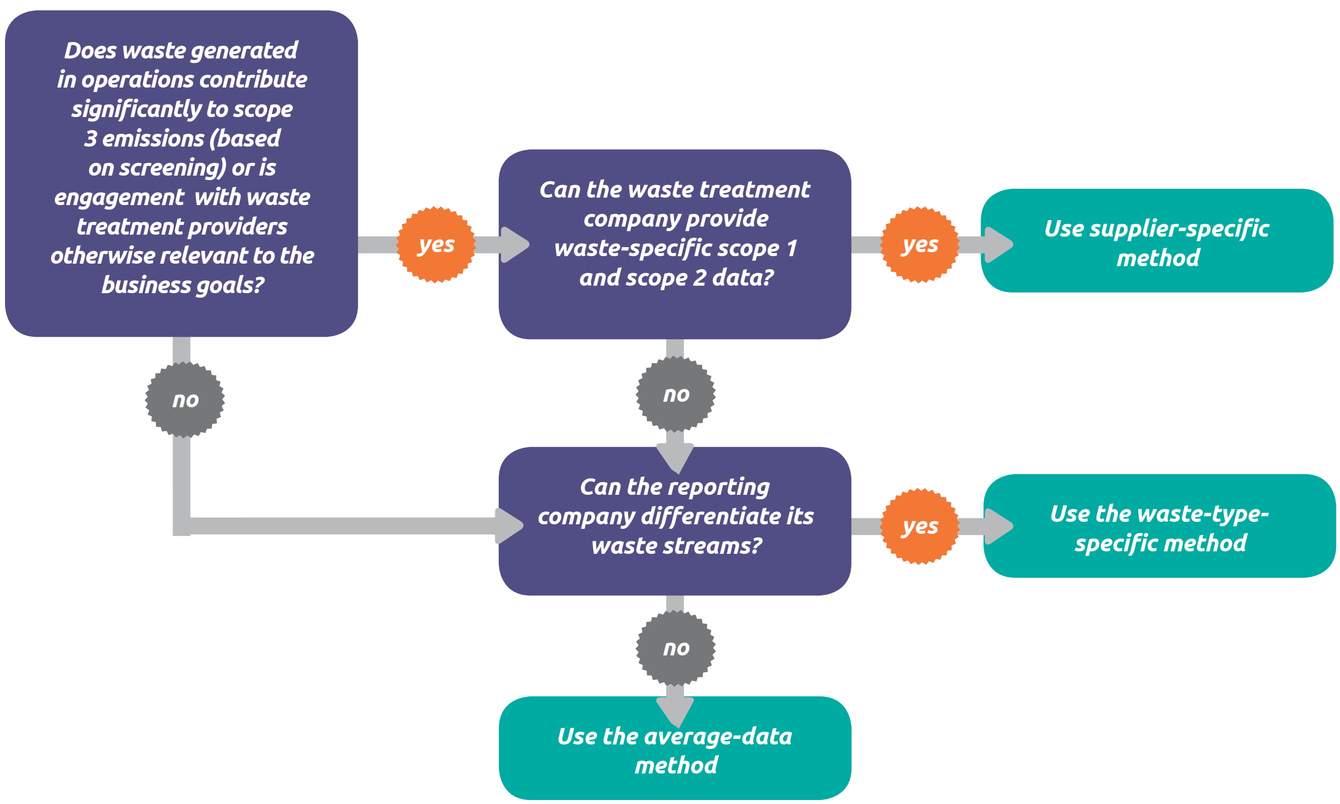
Companies may use any one of the following methods to calculate emissions from waste generated in their operations, but managed by third parties:

- **Supplier-specific method**, which involves collecting waste-specific scope 1 and scope 2 emissions data directly from waste treatment companies (e.g., for incineration, recovery for recycling)
- **Waste-type-specific method,** which involves using emission factors for specific waste types and waste treatment methods
- **Average-data method,** which involves estimating emissions based on total waste going to each disposal method (e.g., landfill) and average emission factors for each disposal method.

To optionally report emissions from the transportation of waste, refer to category 4 (Upstream transportation and distribution) for calculation methodologies.

Figure 5.2 gives a decision tree for selecting a calculation method for emissions from waste generated in operations.

Figure [5.2] Decision tree for selecting a calculation method for emissions from waste generated in operations



Supplier-specific method

In certain cases, third party waste-treatment companies may be able to provide waste-specific scope 1 and scope 2 emissions data directly to customers (e.g., for incineration, recovery for recycling).

Activity data needed

Companies should collect:

- Allocated scope 1 and scope 2 emissions of the waste-treatment company (allocated to the waste collected from the reporting company).

Emission factors needed

If using the supplier-specific method, the reporting company collects emissions data from waste treatment companies, so no emission factors are required (the company would have already used emission factors to calculate the emissions).

Calculation formula [5.1] Supplier-specific method

CO_2e emissions from waste generated in operations =

sum across waste treatment providers:

∑ allocated scope 1 and scope 2 emissions of waste treatment company

Waste-type-specific method

Emissions from waste depend on the type of waste being disposed of, and the waste diversion method. Therefore, companies should try to differentiate waste based on its type (e.g., cardboard, food-waste, wastewater) and the waste treatment method (e.g., incinerated, landfilled, recycled, wastewater).

Activity data needed

Companies should collect:

- Waste produced (e.g., tonne/ cubic meter) and type of waste generated in operations
- For each waste type, specific waste treatment method applied (e.g., landfilled, incinerated, recycled).

Because many waste operators charge for waste disposal by the method used, disposal methods may be identified on utility bills. The information may also be stored on internal IT systems. Companies with leased facilities may have difficulty obtaining primary data. Guidance on improving data collection can be found in chapter 7 of the *Scope 3 Standard*.

Emission factors needed

Companies should collect:

- Waste type-specific and waste treatment-specific emission factors. The emission factors should include end-of-life processes only. Emission factors may include emissions from transportation of waste.

Data collection guidance

Data sources for emission factors include:

- Calculated emission factors using IPCC Guidelines (*2006 IPCC Guidelines for National Greenhouse Gas Inventories Volume 5)*, available at http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol5.html
- Life cycle databases
- Industry associations.

Calculation formula [5.2] Waste-type-specific method

CO_2e emissions from waste generated in operations =

sum across waste types:

∑ (waste produced (tonnes or m^3) × waste type and waste treatment specific emission factor (kg CO_2e/tonne or m^3))

Example [5.1] Calculating emissions from waste generated in operations using the waste-type-specific method

Company A manufactures plastic components and produces solid waste as well as a high volume of wastewater in the manufacturing process. The company collects data on the different types of waste produced, and how this waste is treated. Emission factors are then sourced for each of the waste types.

Waste type	*Waste produced*	*Waste treatment*	*Waste type and waste treatment specific emission factor**
Plastic	2,000 t	Landfill	40 kg CO_2e/t
Plastic	5,000 t	Incinerated with energy recovery	2 kg CO_2e/t[a]
Plastic	4,000 t	Recycled	10 kg CO_2e/t[b]
Water disposal	5,000 m^3	Wastewater	0.5 kg CO_2e/m^3

Notes: the activity data and emission factors in this example are for illustrative purposes only.

a. Includes emissions from preparation and transportation not allocated to the energy produced.

b. Includes emissions from material recovery in preparation for recycling not allocated to the recycled material.

∑ (waste produced (tonnes)
× waste type and waste treatment specific emission factor (kg CO_2e/tonne or m^3))
= (2,000 × 40) + (5,000 × 2) + (4,000 × 10) + (5,000 × 0.5) = 132,500 kg CO_2e

Average-data method

Companies using the average-data method should collect data based on the total waste diversion rates from the reporting organization. This is often preferable where the type of waste produced is unknown. However, this method has a higher degree of uncertainty than the waste-type-specific method.

Activity data needed

Companies should collect:

- Total mass of waste generated in operations
- Proportion of this waste being treated by different methods (e.g., percent landfilled, incinerated, recycled).

Because many waste operators charge for waste by disposal method, this data may be collected from utility bills. The information may also be stored on internal IT systems.

Emission factors needed

Companies should collect:

- Average waste treatment specific emission factors based on all waste disposal types. The emission factors should include end-of-life processes only.

Data collection guidance

Data sources for emission factors include:

- Life cycle databases
- National inventories.

Calculation formula [5.3] Average-data method

CO_2e emissions from waste generated in operations =

sum across waste treatment methods:

∑ (total mass of waste (tonnes) × proportion of total waste being treated by waste treatment method × emission factor of waste treatment method (kg CO_2e/tonne))

Example [5.2] Calculating emissions from waste generated in operations using the average-data method

Company A is a telesales center. The company does not have sufficient information to allow the waste-type specific data method. Company A, therefore, collects data on the total waste collected, the proportion of waste treated by various methods, and average emission factors for waste diversion methods:

Total waste produced (tonnes)	*Waste treatment*	*Proportion (percent)*	*Average emission factor of waste treatment method (kg CO_2e/tonne)*
40	Landfill	25	300
	Incinerated with energy recovery	5	0[a]
	Recycled	30	0[b]
	Recycled	20	10[c]
	Composted	20	30

Notes: the activity data and emission factors in this example are for illustrative purposes only.

a. Emissions from preparation and transportation have been allocated to the energy produced.

b. Emissions from material recovery in preparation for recycling have been allocated to the recycled material.

c. Emissions from material recovery in preparation for recycling have not been allocated to the recycled material.

$$\begin{gathered}\sum \text{(total mass of waste (tonnes)} \\ \times \text{ proportion of total waste being treated by waste treatment method} \\ \times \text{ emission factor of waste treatment method (kg } CO_2e\text{/tonne))} \\ = (40 \times 0.25 \times 300) + (40 \times 0.05 \times 0) + (40 \times 0.3 \times 0) + (40 \times 0.2 \times 10) + (40 \times 0.2 \times 30) \\ = 3{,}320 \text{ kg } CO_2e\end{gathered}$$

Accounting for emissions from recycling

Emission reductions associated with recycling are due to two factors:

- The difference in emissions between extracting and processing virgin material versus preparing recycled material for reuse
- A reduction in emissions that would otherwise have occurred if the waste had been sent to a landfill or other waste treatment method.

Companies may encounter recycling in three circumstances, each of which is relevant to a different scope 3 category (see table 5.1 and figure 5.1).

Table [5.1] Accounting for emissions from recycling across different scope 3 categories

Circumstance	*Relevant scope 3 category*
A Company purchases material with recycled content	Category 1 (Purchased goods and services), or Category 2 (Capital goods)
B Company generates waste from its operations that is sent for recycling	Category 5 (Waste generated in operations)
C Company sells products with recyclable content	Category 12 (End-of-life treatment of sold products)

Under circumstance A (table 5.1), if a company purchases a product or material that contains recycled content, the upstream emissions of the recycling processes are built into the cradle-to-gate emission factor for that product and would, therefore, be reflected in category 1 (Purchased goods and services). If a company purchases a recycled material that has lower upstream emissions than the equivalent virgin material then this would register as lower emissions in category 1. Under circumstance B, a company may recycle some of its "operational waste". These emissions are reported under category 5 (Waste generated in operations). Under circumstance C, products with recyclable content eventually become waste, which could be recycled. Emissions generated in this process are reported as category 12 (End-of-life treatment of sold products). (See figure 5.1.)

Because one company may both purchase recycled materials and sell recyclable products, methodologies have been established to keep the emissions from being double counted. To allocate the emissions from the recycling process between the disposer of the waste and the user of the recycled material, the recommended allocation method is the "recycled content method." This method allocates the emissions to the company that uses the recycled material (reported as category 1).

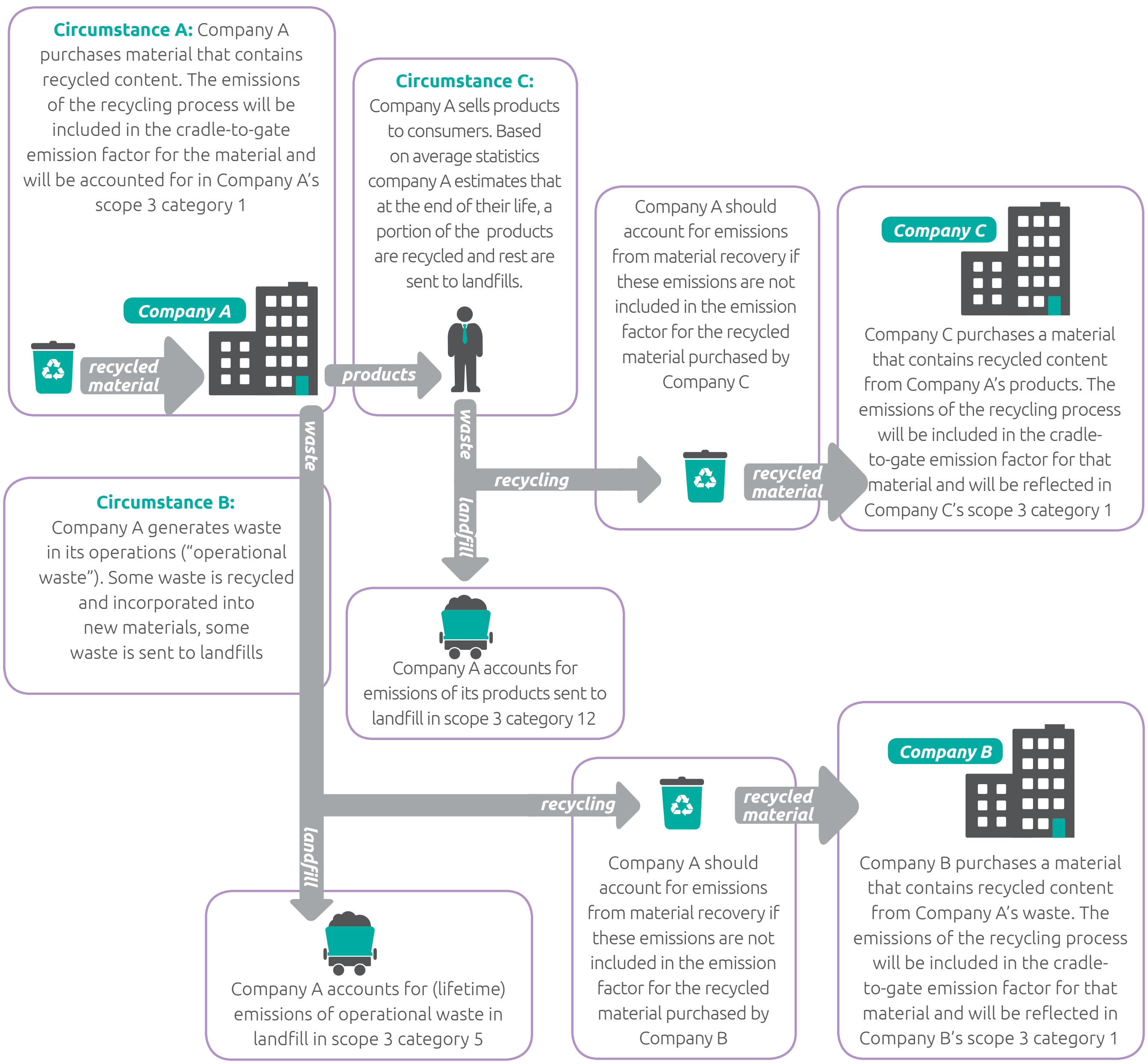
If there is doubt about which processes are allocated to the recycled material (circumstance A), it may be helpful to look at which processes are included in the cradle-to-gate emission factor for the material when it is used as an input. Any processes not included in that factor, but applicable to the company's supply chain, should be included in category 5 or category 12 because they have not been allocated to the recycled material.

The recycled content method is recommended for scope 3 inventories because it is easy to use and generally consistent with secondary emission factors available for recycled material inputs. However, companies may use other methods if they are more applicable to specific materials in their supply chain. For example, the "closed loop approximation method" may be applicable when a recycled material output has the same inherent properties as virgin material input into the same supply chain. This method, also defined in more detail in section 9.3.6 of the Product Standard, accounts for the impact that end-of-life recycling has on the net virgin acquisition of a material. If there is uncertainty about which recycling method is appropriate for a given material or if the supply chain is complex, the recycled content method is the recommended choice to avoid double counting or miscounting of emissions.

Reporting negative or avoided emissions from recycling

Claims of negative or avoided emissions associated with recycling are claims beyond a reduction in processing emissions (as described in circumstance A above) and beyond a reduction in waste treatment emissions in categories 5 or 12 (as described in circumstances B and C above). Negative or avoided emissions claims refer to a comparison of the emissions from processing the recycled material relative to the emissions from producing the equivalent virgin material. Any claims of avoided emissions associated with recycling should not be included in, or deducted from, the scope 3 inventory, but may instead be reported separately from scope 1, scope 2, and scope 3 emissions. Companies that report avoided emissions should also provide data to support the claim that emissions were avoided (e.g., that recycled materials are collected, recycled, and used) and report the methodology, data sources, system boundary, time period, and other assumptions used to calculate avoided emissions. For more information on avoided emissions, see section 9.5 of the *Scope 3 Standard* (see also "Reporting additional metrics for recycling and waste-to-energy," below).

Figure [5.1] Using the recycled content method to account for emissions from recycling



Accounting for emissions from incineration with energy recovery (waste-to-energy)

Attributing emissions from waste-to-energy is similar to the approach taken for recycling. Companies may both generate waste that is incinerated with energy recovery (waste-to-energy) and consume energy that is generated by waste-to-energy processes. If a company purchases energy from the same facility that it sends its waste to, then accounting for emissions from the waste-to-energy combustion process both upstream and downstream would double count the emissions. To avoid double counting, a company should account for upstream emissions from purchased energy generated from waste in scope 2. (In most cases, the emissions associated with combustion of waste to produce energy will be included in the grid average emission factor). Companies should account for emissions from preparing and transporting waste that will be combusted in a waste-to-energy facility in category 5, but should not account for emissions from the waste-to-energy combustion process itself. These emissions should be included in scope 2 by the consumers of energy generated from waste.

If waste from operations is incinerated and used for energy on-site and under operational or financial control, the emissions associated with the incineration are included as scope 1 (and scope 2 would decrease as a result of a reduction in purchased energy). Companies should not report negative or avoided emissions associated with waste-to-energy in the inventory.

This guidance does not apply to accounting for emissions from waste that is incinerated without energy recovery. All emissions from combusting waste without energy recovery are reported by the company generating the waste under scope 3, category 5 (Waste generated in operations).

Reporting additional information for recycling and waste-to-energy

Under the accounting methodology described above, emissions from recycling and waste-to-energy both appear to have a similar effect on the reporting company's scope 3 category 5 emissions (i.e., emissions from both will be reported as close to zero) based on the scope 3 boundary definition. It is, therefore, suggested that companies separately report additional information to help identify the full GHG impacts within and outside their inventory boundary and make informed decisions about the best options for waste treatment (e.g. recycling compared to waste-to-energy).

If electricity is generated from waste-to-energy, companies may report separately the emissions per unit of net electrical generation from the combustion stage of waste-to-energy relative to the local grid average electricity emission factor (tonnes CO_2e per kWh). For example incinerating plastic waste is likely to be more carbon-intensive per kWh of electricity generated than the grid average. Reporting this metric would help companies understand whether sending their waste to a waste-to-energy facility is leading to more- or less-carbon-intensive electricity for the region.

Similarly in the case of recycling, it is suggested that companies report separately the recycling emissions relative to the emissions from producing the equivalent virgin material. This number will often be a negative emissions figure (as recycled material inputs generally have lower upstream emissions than virgin materials). If reported, this figure must be reported separately to the scope 3 inventory.

Accounting for emissions from wastewater

Emissions from wastewater are highly variable depending on how much processing is needed to treat the water (determined by biological oxygen demand [BOD] and/or chemical oxygen demand [COD]). The following industries often have higher emissions from wastewater (where wastewater is not treated onsite): starch refining; alcohol refining; pulp and paper; vegetables, fruits, and juices; and food processing. Companies in these industries should calculate emissions from wastewater using methods provided in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories Volume 5 Waste*, available at http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol5.html.

6

Category 6: Business Travel

Category description

This category includes emissions from the transportation of employees for business-related activities in vehicles owned or operated by third parties, such as aircraft, trains, buses, and passenger cars.

Emissions from transportation in vehicles owned or controlled by the reporting company are accounted for in either scope 1 (for fuel use), or in the case of electric vehicles, scope 2 (for electricity use). Emissions from leased vehicles operated by the reporting company not included in scope 1 or scope 2 are accounted for in scope 3, category 8 (Upstream leased assets). Emissions from transportation of employees to and from work are accounted for in scope 3, category 7 (Employee commuting). See table 6.1.

Emissions from business travel may arise from:

- Air travel
- Rail travel
- Bus travel
- Automobile travel (e.g., business travel in rental cars or employee-owned vehicles other than employee commuting to and from work)
- Other modes of travel.

Companies may optionally include emissions from business travelers staying in hotels.

A reporting company's scope 3 emissions from business travel include the scope 1 and scope 2 emissions of transportation companies (e.g., airlines).

Table [6.1] Accounting for employee transportation across the value chain

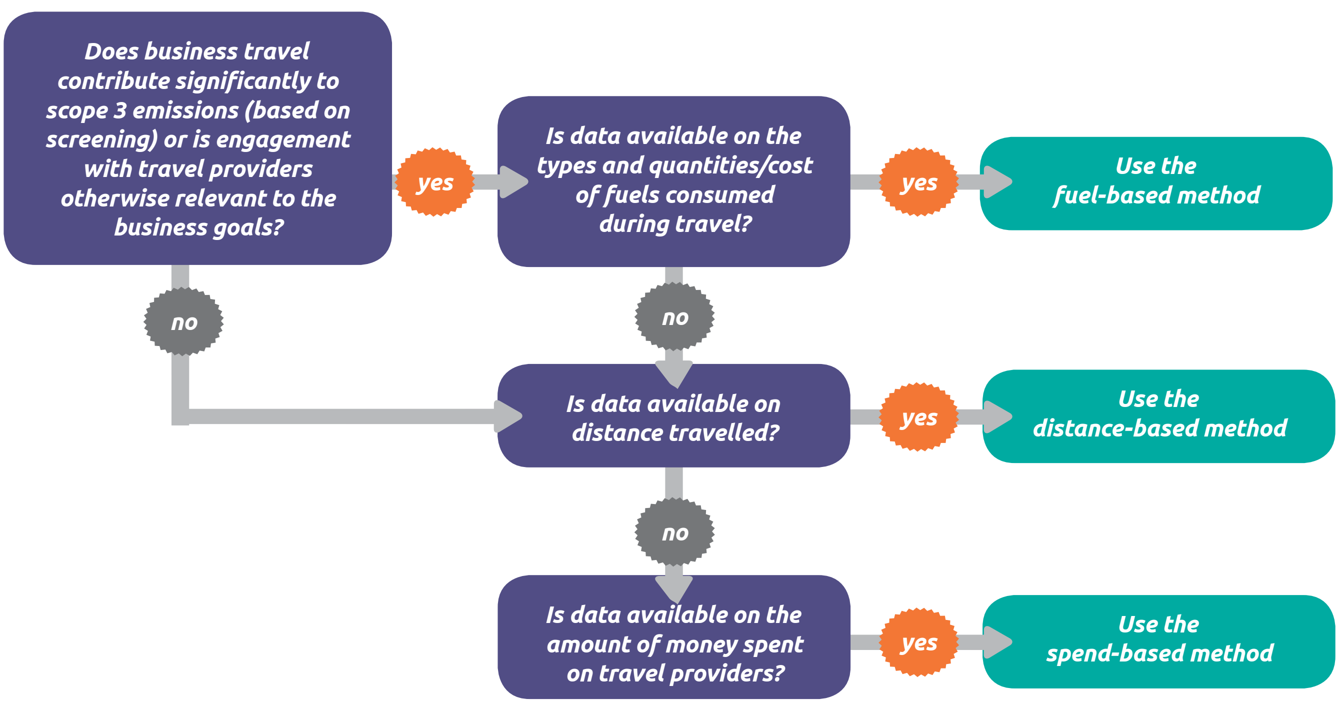
Activity	*Relevant category of emissions*
Emissions from transportation in vehicles owned or controlled by the reporting company	Scope 1 (for vehicles that consume fuel) and scope 2 (for vehicles that consume electricity)
Emissions from the transportation of employees for business-related activities in vehicles owned or operated by third parties	Scope 3, category 6 (Business travel)
Emissions from transportation of employees to and from work	Scope 3, category 7 (Employee commuting)
Emissions from leased vehicles operated by the reporting company not included in scope 1 or scope 2	Scope 3, category 8 (Upstream leased assets)

Calculating emissions from business travel

Figure 6.1 gives a decision tree for selecting a calculation method for emissions from business travel. Companies may use one of the following methods to calculate scope 3 emissions from business travel:

- **Fuel-based method**, which involves determining the amount of fuel consumed during business travel (i.e., scope 1 and scope 2 emissions of transport providers) and applying the appropriate emission factor for that fuel
- **Distance-based method**, which involves determining the distance and mode of business trips, then applying the appropriate emission factor for the mode used
- **Spend-based method**, which involves determining the amount of money spent on each mode of business travel transport and applying secondary (EEIO) emission factors.

Figure [6.1] Decision tree for selecting a calculation method for emissions from business travel



Fuel-based method

The calculation methodology for the fuel-based method does not differ from the fuel-based method in category 4 (Upstream transport and distribution). For guidance on calculating emissions using this method, refer to the guidance for category 4 (Upstream transport and distribution). Companies may optionally collect data on the number of hotel nights incurred during business travel by hotel type. Under this method, they add the number of hotel nights and the emissions factor of the hotel (as shown in the distance-based method below) to the fuel-based method in category 4 (Upstream transport and distribution).

Distance-based method

If data on fuel use is unavailable, companies may use the distance-based method.

The distance-based method involves multiplying activity data (i.e., vehicle-kilometers or person-kilometers travelled by vehicle type) by emission factors (typically default national emission factors by vehicle type). Vehicle types include all categories of aircraft, rail, subway, bus, automobile, etc.

Activity data needed

Companies should collect data on:

- Total distance travelled by each mode of transport (air, train, bus, car, etc.) for employees in the reporting year.

Where possible, companies should also collect data on:

- Countries of travel (since transportation emission factors vary by country)
- Specific types of vehicles used for travel (since transportation emission factors vary by vehicle types) from transport providers
- The specific passenger vehicle type and the relevant emission factor.

Companies may optionally collect data on the number of hotel nights incurred during business travel by hotel type.

Activity data should be expressed as the number of kilometers travelled or kilometers travelled per person for a particular vehicle type (e.g., passenger-kilometer). The activity data should be summed to obtain total annual kilometers or person-kilometers travelled by each vehicle type used by the company.

Emission factors needed

Companies should collect:

- Emission factors for each mode of transport (e.g., aircraft, rail, metro, bus, taxi, bus), expressed in units of greenhouse gas (CO_2, CH_4, N_2O, HFC, or CO_2e) emitted per kilometer or per passenger-kilometer travelled.

Companies may optionally use emission factors for hotel stays by hotel type (e.g., kilograms of CO_2e emitted per hotel night).

Note: For air travel emission factors, multipliers or other corrections to account for radiative forcing may be applied to the GWP of emissions arising from aircraft transport. If applied, companies should disclose the specific factor used.

Data collection guidance

Methods of data collection include:

- Automatic tracking of distance travelled by mode through a travel agency or other travel providers
- Automatic tracking of distance travelled by mode through internal expense and reimbursement systems, which may require adding new questions on distance travelled and mode of transport to travel or expense forms submitted by employees
- Annual surveys/questionnaires of employees
- Working with travel providers (e.g., transportation companies, hotels) to obtain GHG emissions data.

Collecting travel data from all employees may not be feasible. In such a case, companies may extrapolate from a representative sample of employees to the total business travel of all employees. For example, a company may have 4,000 employees, each of whom has different travel profiles. The company may extrapolate from a representative sample of 400 employees to approximate the total business travel of all employees. Companies may also choose to group or combine data from business travellers with similar travel profiles. See Appendix A for more information on sampling methods.

Calculation resources include:

- GHG Protocol Calculation Tool, "Mobile Combustion GHG Emissions Calculation Tool. Version 2.0. June 2009," developed by World Resources Institute, available at http://www.ghgprotocol.org/calculation-tools/all-tools
- U.S. EPA Climate Leaders GHG Inventory Protocol, "Optional Emissions from Commuting, Business Travel and Product Transport," available at: http://www.epa.gov/stateply/documents/resources/commute_travel_product.pdf
- For UK organizations, the Department for Transport provides guidance and a calculation tool for work-related travel at: http://www2.dft.gov.uk/pgr/sustainable/greenhousegasemissions/.

Once the company has determined total annual distance travelled by each mode of transport (aggregated across all employees), apply the formula below to calculate emissions.

Calculation formula [6.1] Distance-based method

CO_2e emissions from business travel =

sum across vehicle types:

∑ (distance travelled by vehicle type (vehicle-km or passenger-km)

× vehicle specific emission factor (kg CO_2e/vehicle-km or kg CO_2e/passenger-km))

\+

(optional)

∑ (annual number of hotel nights (nights) × hotel emission factor (kg CO_2e/night))

Example [6.1] Calculating emissions from business travel using the distance-based method

Company A is a financial services company. Every year, it sends groups of professionals to industry conferences in the United Kingdom, Australia, and the United States. For each group, the company has collected activity data on the typical distances travelled and modes of transport.

Data was collected via employee questionnaires and information provided by travel agencies and transportation companies. It is assumed that each member of the group travelled the same amount in the same business trip.

Road Travel

Employee Group	Number of employees in group	Car type	Average employees per vehicle	Location	Distance (km)	Emission factor (kg CO_2e/ vehicle-km)
Group 1	10	Hybrid	2	United States	50	1
Group 2	20	Average gasoline car	2	Australia	200	2
Group 3	100	Four wheel drive	3	United States	100	4

Air Travel

Employee Group	Number of employees in group	Flight type	Distance (km)	Emission factor (kg CO_2e/passenger-km)
Group 1	10	Long haul	10,000	5
Group 2	20	Short haul	15,000	6
Group 3	100	Long haul	12,000	5

Note: the activity data and emission factors in this example are for illustrative purposes only.

Example [6.1] Calculating emissions from business travel using the distance-based method (continued)

Three types of flights are identified for calculating emission factors. Short-haul flights have higher emission factors due to strong influence of the landing/take off cycle on emissions, whereas long-haul flights have slightly higher emissions than medium-haul flights due to the additional weight of fuel. Many countries have specific definitions of types of flights. Below is an indicative description:

- Short haul – flights less than 3 hours in length
- Medium haul – flights 3-6 hours in length
- Long haul – journeys made by wide-bodied aircrafts that fly long distance, typically more than 6.5 hours.

total business travel emissions of Company A can be calculated as follows:

emissions from road travel = ∑ (distance travelled by vehicle type (vehicle-km or passenger-km)
× vehicle specific emission factor (kg CO_2e/vehicle-km or kg CO_2e/passenger-km))
= (10/2 × 50 × 1) + (20/2 × 200 × 2) + (100/3 × 100 × 4)
= 17,583.33 kg CO_2e

emissions from air travel = ∑ (distance travelled by vehicle type (vehicle-km or passenger-km)
× vehicle specific emission factor (kg CO_2e/vehicle-km or kg CO_2e/passenger-km))
= (10 × 10,000 × 5) + (20 × 15,000 × 6) + (100 × 12,000 × 5)
= 8,300,000 kg CO_2e

total emissions from employee travel = emissions from road travel + emissions from air travel
= 17,583.33 + 8,300,000
= 8,317,583.33 kg CO_2e

Spend-based method

If it is not possible to use either the fuel- or distance-based methods, companies may use the spend-based method. The calculation method is same as the spend-based method described in Category 4: Upstream Transportation and Distribution, with the difference that the activity data is the amount spent on business travel by type/mode of transport. Refer to the spend-based method in Category 4 for a description of this method.

Companies may optionally collect data on the number of hotel nights incurred during business travel by hotel type.

7

Category 7: Employee Commuting

Category description

This category includes emissions from the transportation of employees[4] between their homes and their worksites. Emissions from employee commuting may arise from:

- Automobile travel
- Bus travel
- Rail travel
- Air travel
- Other modes of transportation (e.g., subway, bicycling, walking).

Companies may include emissions from teleworking (i.e., employees working remotely) in this category.

A reporting company's scope 3 emissions from employee commuting include the scope 1 and scope 2 emissions of employees and third-party transportation providers.

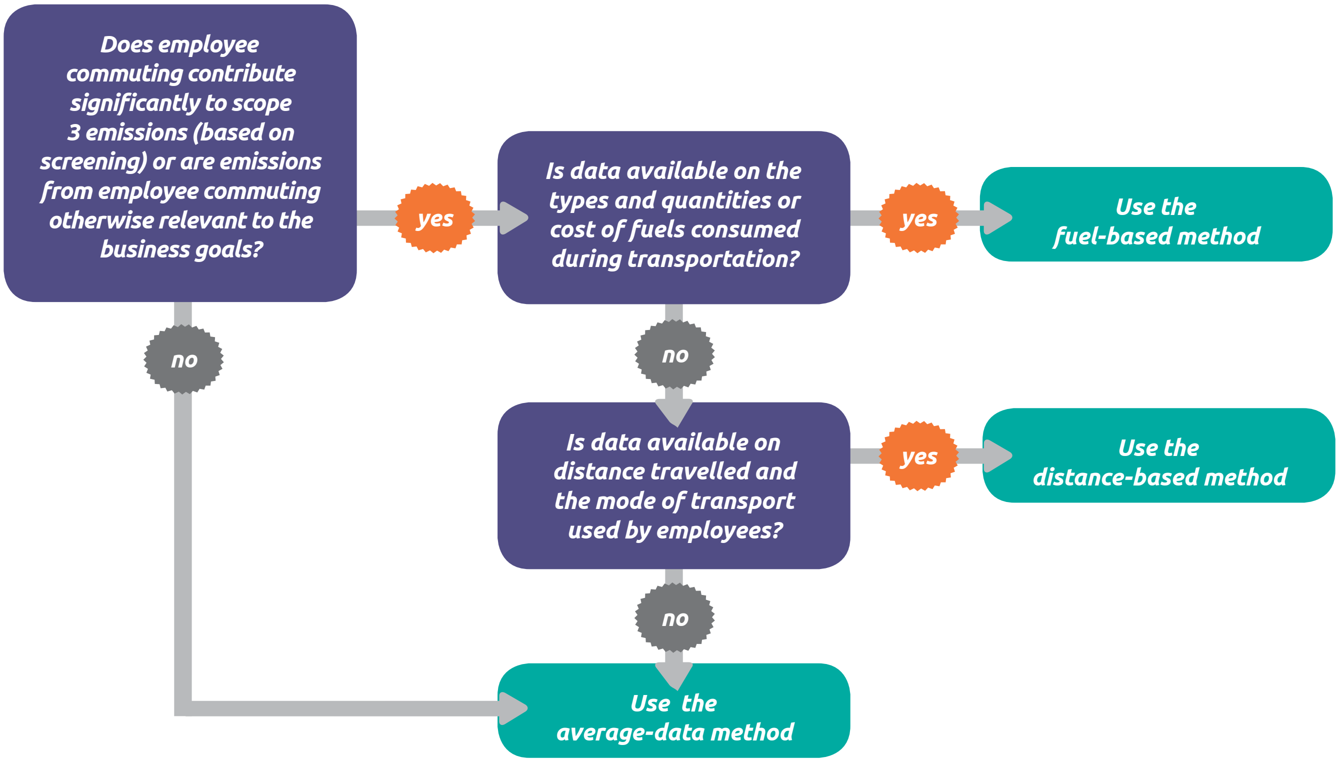
Calculating emissions from employee commuting

Figure 7.1 offers a decision tree for selecting a calculation method for scope 3 emissions from employee commuting. Companies may use one of the following methods:

- **Fuel-based method**, which involves determining the amount of fuel consumed during commuting and applying the appropriate emission factor for that fuel
- **Distance-based method,** which involves collecting data from employees on commuting patterns (e.g., distance travelled and mode used for commuting) and applying appropriate emission factors for the modes used
- **Average-data method**, which involves estimating emissions from employee commuting based on average (e.g., national) data on commuting patterns.

4 "Employees" refers to employees of entities and facilities owned, operated, or leased by the reporting company. Companies may include employees of other relevant entities (e.g., franchises or outsourced operations) in this category, as well as consultants, contractors, and other individuals who are not employees of the company, but commute to facilities owned and operated by the company.

Figure [7.1] Decision tree for selecting a calculation method for emissions from employee commuting



Fuel-based method

If data is available on the quantity or amount spent on fuel by employees for commuting, companies may apply the fuel-based method. The calculation methodology for the fuel-based method is the same as the fuel-based method in category 4 (Upstream transport and distribution). For guidance on calculating emissions using this method, refer to the guidance for category 4 (Upstream transport and distribution). If the fuel-based method is used to calculate emissions from commuting on public transport, then emissions need to be allocated to the employee(s). For more information on allocation, see chapter 8 of the *Scope 3 Standard*.

Distance-based method

Activity data needed

Companies should collect data on the following:

- Total distance travelled by employees over the reporting period (e.g., passenger-kilometers travelled)
- Mode of transport used for commuting (e.g., train, subway, bus, car, bicycle).

Emission factors needed

Companies should collect:

- Emission factors for each mode of transport (usually expressed in units of greenhouse gas (CO_2, CH_4, N_2O, or CO_2e) emitted per passenger-kilometers travelled).

Note: For air travel emission factors, multipliers or other corrections to account for radiative forcing may be applied to the GWP of emissions arising from aircraft transport. Where used, companies should disclose the specific factor used.

Data collection guidance

Companies should collect data on employee commuting habits, for example through a survey. Companies should survey their employees annually to obtain information on average commuting habits. Types of data to collect include:

- Distance travelled by employees per day, or location of residence and office
- The number of days per week that employees use different vehicle types (all categories of subway, car, bus, train, bicycle, etc.)
- Number of commuting days per week and number of weeks worked per year
- If the company is multinational: employees' region of residence/work (since transportation emission factors vary by region)
- Whether there is a significant car-pooling scheme in operation, the proportion of employees using the scheme and the average occupancy per vehicle
- If applicable, the amount of energy used from teleworking (e.g., kWh of gas, electricity consumed).

Collecting commuting data from all employees through a survey may not be feasible. Companies may extrapolate from a representative sample of employees to represent the total commuting patterns of all employees. For example, a company with 4,000 employees, who each have different commuting profiles, may extrapolate from a representative sample of, for example, 1,000 employees to approximate the total commuting of all employees. See Appendix A for more information on sampling.

Calculation formula [7.1] Distance-based method

CO_2e emissions from employee travel =

first, sum across all employees to determine total distance travelled using each vehicle type:

total distance travelled by vehicle type (vehicle-km or passenger-km)
= ∑ (daily one-way distance between home and work (km) × 2 × number of commuting days per year)

then, sum across vehicle types to determine total emissions:

kg CO_2e from employee commuting
= ∑ (total distance travelled by vehicle type (vehicle-km or passenger-km)
× vehicle specific emission factor (kg CO_2e/vehicle-km or kg CO_2e/passenger-km))
+
(optionally) for each energy source used in teleworking:
∑ (quantities of energy consumed (kWh) × emission factor for energy source (kg CO_2e/kWh))

Companies should convert daily commuting distance into annual commuting distance by multiplying the daily distance by the number of times the trip occurs during the reporting period. For example, if a company collects distance data on one-way journeys, the company should multiply the distance by the number of working days in the reporting year, and then multiply by two to account for daily return journeys.

Distance-travelled data by transport mode should be summed across all employees to obtain total annual kilometers or passenger-kilometers travelled by each mode of transport.

Companies may optionally calculate the emissions of teleworking from home. To calculate these emissions, a baseline emissions scenario should first be established. Baseline emissions occur regardless of whether or not the employee was at home (e.g., energy consumed by the refrigerator). The reporting company should only account for the additional emissions resulting from working from home, for example the electricity usage as a result of running the air conditioner to stay cool.

Example [7.1] Calculating emissions from employee travel using the distance-based method

Company A is a small advertising services company, with three employees working 48 weeks per year. To calculate emissions from employee commuting, it creates an “employee commuting profile” for each employee. Each employee completes a questionnaire the results of which are summarized in the following table:

Employee	Rail commute (times per week)	One way distance by rail (km)	Rail emission factor (kg CO_2e/ passenger-kilometer)	Car commute (times per week	Car emission factor (kg CO_2e/ vehicle-kilometer)	One way distance by car (km)
A	5	10	0.1	0	0.2	N/A
B	4	10	0.1	1	0.2	15
C	0	N/A	0.1	5	0.2	20

Note: The activity data and emissions factors are illustrative only, and do not refer to actual data.

the total distance travelled by rail (km) is calculated as:

∑ (daily one way distance between home and work (km) × 2 × 5 × number of commuting weeks per year)

= (10 × 2 × 5 × 48) + (10 × 2 × 4 × 48) = 8,640 km

the total distance travelled by car (km) is calculated as:

∑ (daily one way distance between home and work (km) × 2 × 5 × number of commuting weeks per year)

= (15 × 2 × 1 × 48) + (20 × 2 × 5 × 48) = 11,040 km

total emissions from employee commuting for the reporting year is calculated as:

∑ (total distance travelled by vehicle type (vehicle-km or passenger-km)

× vehicle specific emission factor (kg CO_2e/vehicle-km or kg CO_2e/passenger-km))

= (8,640 × 0.1) + (11,040 × 0.2) = 3,072 kg CO_2e

Average-data method

If company specific data is unavailable, companies may use average secondary activity data to estimate distance travelled and mode of transport. This may include using:

- Average daily commuting distances of typical employees
- Average modes of transport of typical employees
- Average number of commuting days per week and average number of weeks worked per year.

Such estimation requires making several simplifying assumptions, which add uncertainty to the emissions estimates.

Activity data needed

Companies should collect data on:

- Number of employees
- Average distance travelled by an average employee per day
- Average breakdown of transport modes used by employees
- Average number working days per year.

Emission factors needed

- Companies should collect:
- Emission factors for each mode of transport (usually expressed as kilograms of GHG emitted per passenger per kilometer travelled).

Data collection guidance

Company may collect average secondary data from sources such as national transportation departments, ministries or agencies, national statistics publications, and/or industry associations.

For example, the UK Office for National Statistics publishes average commuting patterns and distances (http://www.neighbourhood.statistics.gov.uk/dissemination/Info.do?page=analysisandguidance/commutingstatistics/commuting-statistics.htm).

Calculation resources include:

- GHG Protocol Calculation Tool, "Mobile Combustion GHG Emissions Calculation Tool. Version 2.0. June 2009," developed by World Resources Institute, available at http://www.ghgprotocol.org/calculation-tools/all-tools
- U.S. EPA Climate Leaders GHG Inventory Protocol, "Optional Emissions from Commuting, Business Travel and Product Transport," available at: http://www.epa.gov/stateply/documents/resources/commute_travel_product.pdf
- For UK organizations, the Department for Transport provides guidance and a calculation tool for work-related travel at: http://www2.dft.gov.uk/pgr/sustainable/greenhousegasemissions/.

Calculation formula [7.2] Average-data method

CO_2e emissions from employee commuting =

sum across each transport mode:
∑ (total number of employees × % of employees using mode of transport
× one way commuting distance (vehicle-km or passenger-km) × 2 × working days per year
× emission factor of transport mode (kg CO_2e/vehicle-km or kg CO_2e/passenger-km))

Companies should convert average daily commuting distance into annual average commuting distance by multiplying the one-way distance by two for the daily return trip and by the average number of days worked per year (i.e., excluding weekends and days spent on business travel, vacation, or working from home).

Example [7.2] Calculating emissions from employee travel using the average data method

Company A is a manufacturer in the United Kingdom with over 10,000 employees. To determine the distance and mode of transport of employee travel, it refers to the UK Department of Transport's information regarding average commute choices and distances of commuters. National statistics show that UK workers work on average 235 days a year. The example assumes that employees do not share rides. The results of the study are shown below:

Commute group	*Percent of total commutes*	*Average one-way distance (km)*	*Emission factor (kg CO_2e/ vehicle or passenger km*
Rail	50	10	0.1
Car	30	15	0.2
Foot	15	1	0.0
Bus	5	5	0.1

Note: The activity data and emissions factors are illustrative only, and do not refer to actual data.

Example [7.2] Calculating emissions from employee travel using the average data method (continued)

CO_2e emissions by mode of transport can be calculated as follows:

emissions from employee commuting = ∑ (total number of employees
× % of employees using mode of transport
× one way commuting distance (vehicle-km or passenger-km) × 2 × working days per year
× emission factor of transport mode (kg CO_2e/vehicle-km or kg CO_2e/passenger-km))

rail commuters:
(10,000 × 50% × 10 × 2 × 235 × 0.1) = 2,350,000 kg CO_2e
car commuters:
(10,000 × 30% × 15 × 2 × 235 × 0.2) = 4,230,000 kg CO_2e
foot commuters:
(10,000 × 15% × 1 × 2 × 235 × 0) = 0 kg CO_2e
bus commuters:
(10,000 × 5% × 5 × 2 × 235 × 0.1) = 117,500 kg CO_2e

total CO_2e of employee travel can be calculated as follows:
= 2,350,000 + 4,230,000 + 0 + 117,500 = 6,697,500kg CO_2e

8

Category 8: Upstream Leased Assets

Category description

Category 8 includes emissions from the operation of assets that are leased by the reporting company in the reporting year and not already included in the reporting company's scope 1 or scope 2 inventories. This category is applicable only to companies that operate leased assets (i.e., lessees). For companies that own and lease assets to others (i.e., lessors), see category 13 (Downstream leased assets).

Leased assets may be included in a company's scope 1 or scope 2 inventory depending on the type of lease and the consolidation approach the company uses to define its organizational boundaries (see section 5.2 of the *Scope 3 Standard*).

If the reporting company leases an asset for only part of the reporting year, it should account for emissions for the portion of the year that the asset was leased. A reporting company's scope 3 emissions from upstream leased assets include the scope 1 and scope 2 emissions of lessors (depending on the lessor's consolidation approach).

See Appendix A of the *Scope 3 Standard* for more information on accounting for emissions from leased assets.

Calculating emissions from leased assets

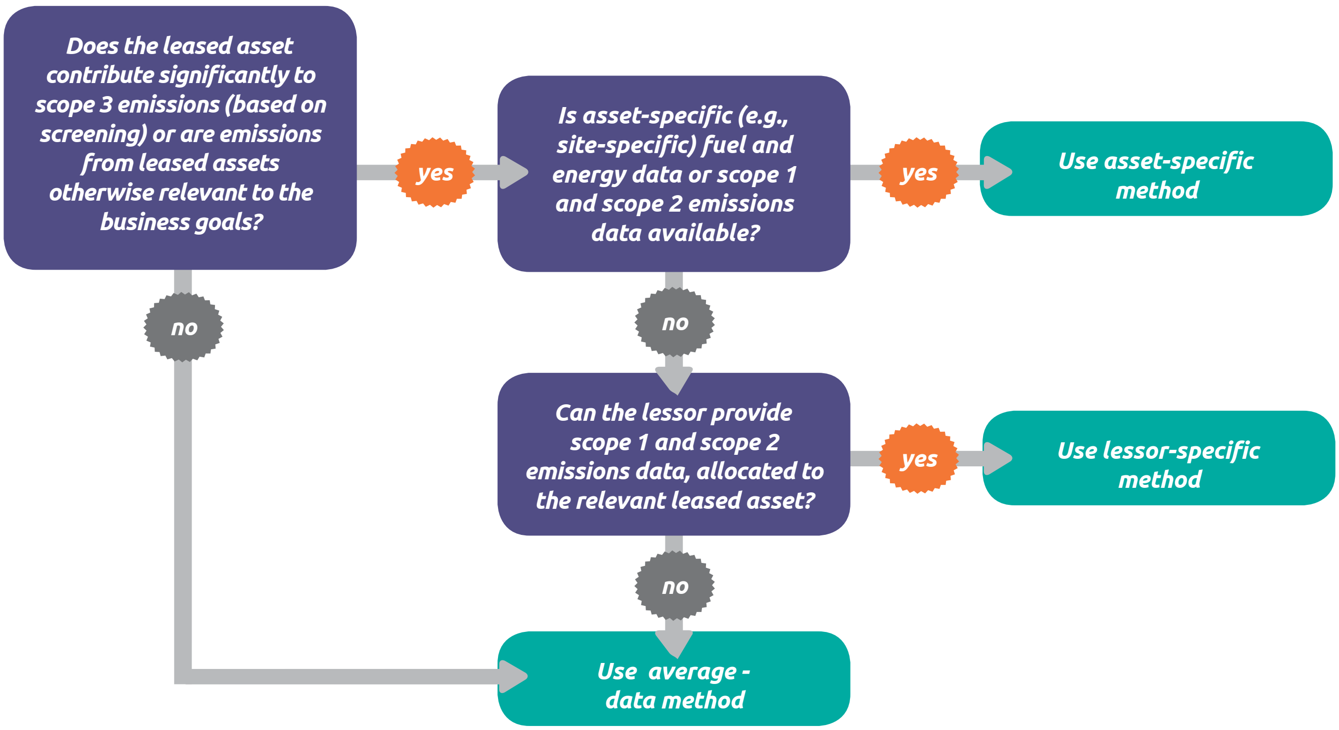
Figure 8.1 shows a decision tree for selecting a calculation method for emissions from upstream leased assets. Companies may use one of the following methods:

- **Asset-specific method**, which involves collecting asset-specific (e.g., site-specific) fuel and energy use data and process and fugitive emissions data or scope 1 and scope 2 emissions data from individual leased assets
- **Lessor-specific method**, which involves collecting the scope 1 and scope 2 emissions from lessor(s) and allocating emissions to the relevant leased asset(s)

- **Average data method**, which involves estimating emissions for each leased asset, or groups of leased assets, based on average data, such as average emissions per asset type or floor space.

Companies may also calculate the life cycle emissions associated with manufacturing or constructing leased assets.

Figure [8.1] Decision tree for selecting a calculation method for emissions from upstream leased assets



Asset-specific method

This method involves collecting asset-specific (e.g., site-specific) fuel and energy and/or scope 1 and scope 2 emissions data from individual leased assets.

Activity data needed

Companies should collect scope 1 and scope 2 emissions data, or activity data on:

- Asset-specific fuel use and electricity, steam, heating and cooling use
- If applicable, activity data related to non-combustion emissions (i.e., industrial process or fugitive emissions).

Emission factors needed

Companies should collect:

- Site or regionally specific emission factors for energy sources (e.g., electricity and fuels) per unit of consumption (e.g., kg CO_2e/kWh for electricity, kg CO_2e/liter for diesel)
- Emission factors of fugitive and process emissions.

To optionally calculate emissions associated with manufacturing or construction of leased assets, companies should use life cycle emission factors that include manufacturing and construction.

Data collection guidance

Data sources for activity data may include:

- Utility bills
- Purchase records
- Meter readings
- Internal IT systems.

Data sources for emission factors include:

- Life cycle databases. A list of life cycle databases is provided on the GHG Protocol website (http://www.ghgprotocol.org/Third-Party-Databases). Additional databases may be added periodically, so continue to check the website.
- Company-developed emission factors
- Government agencies (e.g., Defra provides emission factors for the UK)
- Industry associations
- For activity data, emission factors, and formulas for process and fugitive emissions, see the GHG Protocol website (http://www.ghgprotocol.org/calculation-tools/all-tools) and the IPCC 2006 Guidelines (http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html).

To calculate scope 3 emissions from leased assets, aggregate the scope 1 and scope 2 emissions across all of the reporting company's leased assets, using this formula:

Calculation formula [8.1] Asset-specific method

CO_2e emissions from upstream leased assets =

calculate the scope 1 and scope 2 emissions associated with each leased asset:

scope 1 emissions of leased asset
= ∑ (quantity of fuel consumed (e.g., liter) × emission factor for fuel source (e.g., kg CO_2e/liter))
+ ∑ ((quantity of refrigerant leakage (kg) × emission factor for refrigerant (kg CO_2e/kg))
+ process emissions)

scope 2 emissions of leased asset
= ∑ (quantity of electricity, steam, heating, cooling consumed (e.g., kWh)
× emission factor for electricity, steam, heating, cooling (e.g., kg CO_2e/kWh))

then sum across leased assets:

∑ scope 1 and scope 2 emissions of each leased asset

Companies that lease a portion of a building (e.g., an office building) where energy use is not separately sub-metered by the tenant may estimate energy consumed using the reporting company's share of the building's total floor space and total building energy use, following this formula:

Calculation formula [8.2] Allocating emissions from leased buildings that are not sub-metered

energy use from leased space (kWh) =

(reporting company's area (m^2)) / (building's total area (m^2)
× building's occupancy rate (e.g., 0.75))
× building's total energy use (kWh)

Example [8.1] Calculating emissions from upstream leased assets using the asset-specific method

Company B leases an entire floor of office space from Company D for one year. Company B is able to collect data on the fuel, electricity, and fugitive emissions of the entire building for the reporting year. Company B leases 200 m^2 of the building's total area of 2,000 m^2. The occupancy rate of the building is 75%.

Data is summarized in the table below:

	Natural gas (kWh)	***Natural gas emission factor (kg CO_2e/kWh)***	***Electricity (kWh)***	***Electricity emission factor (kg CO_2e/kWh)***	***Fugitive emissions***	***Fugitive emission factor***
Building	1,500	0.2	3,000	0.7	5	1,500

Note: The activity data and emissions factors are illustrative only, and do not refer to actual data.

Example [8.1] Calculating emissions from upstream leased assets using the asset-specific method (continued)

Total natural gas allocation to company B:

$$\frac{\text{(reporting company's area (m}^2\text{)}}{\text{building's total area (m}^2\text{)} \times \text{building's occupancy rate (e.g., 0.75)}}$$

$$\times \text{ building's total natural gas use}$$

= 200 / (2000 × 0.75) × 1500
= 200 kWh

total electricity allocation to company B:

$$\frac{\text{reporting company's area (m}^2\text{)}}{\text{building's total area (m}^2\text{)} \times \text{building's occupancy rate (e.g., 0.75)}}$$

$$\times \text{ building's total electricity use}$$

= (200 / (2000 × 0.75) × 3000
= 400 kWh

total fugitives allocation to company B:

$$\frac{\text{reporting company's area (m}^2\text{)}}{\text{building's total area (m}^2\text{) building's occupancy rate (e.g., 0.75)}}$$

$$\times \text{ building's total fugitive emissions}$$

= (200 / (2000 × 0.75) × 5
= 0.67 kg

total emissions of leased asset:

= (200 × 0.2) + (400 × 0.7) + (0.67 × 1500)
= 1,325 kg CO_2e

Lessor-specific method

The lessor-specific method involves collecting the scope 1 and scope 2 emissions from lessor(s) and allocating emissions to the relevant leased asset(s). This method is relevant in cases where, for example, office space is leased in a building that is not sub-metered. If the lessor company has data available at the building- or company-level, allocation techniques can be used to apportion emissions to the office space leased by the reporting company.

Activity data needed

Companies should collect lessors' total scope 1 and scope 2 emissions data, or activity data on:

- Lessor's total fuel use and electricity use
- Lessor's fugitive emissions (e.g., from refrigerants)
- Lessor's process emissions (if applicable).

Emission factors needed

- Site or regionally specific emission factors for energy sources (e.g., electricity and fuels) per unit of consumption (e.g., kg CO_2e/kWh for electricity, kg CO_2e/liter for diesel)
- Emission factors of fugitive and process emissions.

To allocate emissions, companies should collect data on:

- Total area/volume/quantity of lessors' assets
- Total area/volume/quantity of the reporting company's leased assets.

For guidance on allocating emissions, refer to chapter 8 of the *Scope 3 Standard*.

Calculation formula [8.3] Lessor-specific method

CO_2e emissions from leased assets =

calculate the scope 1 and scope 2 emissions associated with each lessor:

scope 1 emissions of lessor
= ∑ (quantity of fuel consumed (e.g., liter) × emission factor for fuel source (e.g., kg CO_2e/liter))
+ ∑ (quantity of refrigerant leakage (kg) × emission factor for refrigerant (kg CO_2e/kg))
+ process emissions

scope 2 emissions of lessor
= ∑ (quantity of electricity, steam, heating, cooling consumed (e.g., kWh)
× emission factor for electricity, steam, heating, cooling (e.g., kg CO_2e/kWh))

then allocate emissions from each lessor and then sum across lessors:

$$\sum \text{(scope 1 and scope 2 emissions of lessor (kg } CO_2e) \times \left(\frac{\text{area, volume, quantity, etc., of the leased asset}}{\text{total area, volume, quantity, etc., of lessor assets}} \right)$$

Average-data method

The average-data method involves estimating emissions for each leased asset, or groups of leased assets, based on average statistics and secondary data, such as average emissions per asset type or floor space. The average-data method should be used when purchase records, electricity bills, or meter readings of fuel or energy use are not available or applicable. Approaches include:

- Estimated emissions based on occupied floor space by asset/building type (for leased buildings)
- Estimated emissions based on number and type of leased assets.

Note that the average-data method is less accurate than the lessor-specific method and limits the ability of companies to track their performance of GHG reduction actions.

Activity data needed

Companies should collect data on:

- Floor space of each leased building
- Number of leased buildings, by building type (e.g., office, retail, warehouse, factory, etc.)
- Number and type of leased assets other than buildings that give rise to scope 1 or scope 2 emissions (e.g., company cars, trucks).

Emission factors needed

Companies should collect:

- Average emission factors by floor space, expressed in units of emissions per square meter, square foot occupied (e.g., kg CO_2e/m^2/year)
- Average emission factors by building type, expressed in units of emissions per building (e.g., kg CO_2e/small office block/year)
- Emission factors by asset type, expressed in units of emissions per asset (e.g., kg CO_2e/car/year).

Data collection guidance

The U.S. Energy Information Administration has developed a dataset on average energy use by building type. Commercial Buildings Energy Consumption Survey, at: http://www.eia.doe.gov/emeu/cbecs

Calculation formula [8.4] Average-data method for leased buildings (where floor space data is available)

CO_2e emissions from leased assets =

sum across building types:

∑ (total floor space of building type (m^2) × average emission factor for building type (kg CO_2e/m^2/year))

Calculation formula [8.5] Average-data method for leased assets other than buildings and for leased buildings where floor space data is unavailable

CO_2e emissions from leased assets =

sum across asset types:

∑ (number of assets x average emissions per asset type (kg CO_2e/asset type/year))

9

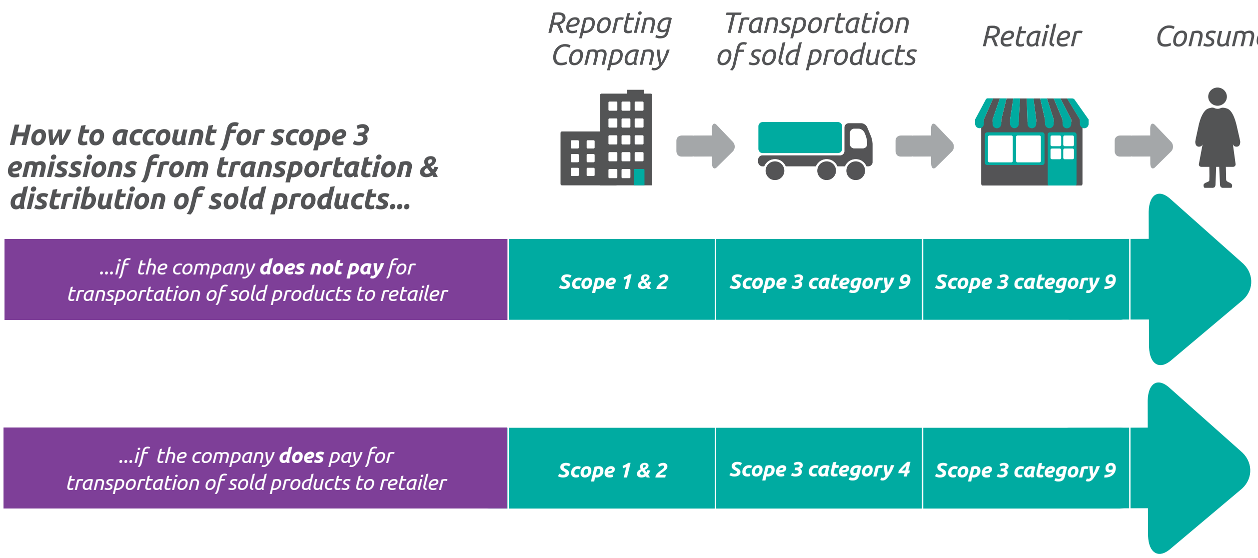
Category 9: Downstream Transportation and Distribution

Category description

This category includes emissions that occur in the reporting year from transportation and distribution of sold products in vehicles and facilities not owned or controlled by the reporting company.

This category also includes emissions from retail and storage. Outbound transportation and distribution services that are purchased by the reporting company are excluded from category 9 and included in category 4 (Upstream transportation and distribution) because the reporting company purchases the service. Category 9 includes only emissions from transportation and distribution of products after the point of sale. See table 5.7 in the *Scope 3 Standard* for guidance in accounting for emissions from transportation and distribution in the value chain.

Figure [9.1] Accounting for emissions from transportation and distribution of sold products



Emissions from downstream transportation and distribution can arise from transportation/storage of sold products in vehicles/facilities not owned by the reporting company. For example:

- Warehouses and distribution centers
- Retail facilities
- Air transport
- Rail transport
- Road transport
- Marine transport.

In this category, companies may include emissions from customers traveling to and from retail stores, which can be significant for companies that own or operate retail facilities. See chapter 5.6 of the *Scope 3 Standard* for guidance on the applicability of category 9 to final products and intermediate products sold by the reporting company. A reporting company's scope 3 emissions from downstream transportation and distribution include the scope 1 and scope 2 emissions of transportation companies, distribution companies, retailers, and (optionally) customers.

If the reporting company sells an intermediate product, the company should report emissions from transportation and distribution of this intermediate product between the point of sale by the reporting company and either (1) the end consumer (if the eventual end use of the intermediate product is known) or (2) business customers (if the eventual end use of the intermediate product is unknown).

Calculating emissions from transportation (downstream)

The emissions from downstream transportation should follow the calculation methods described in category 4 (Upstream transportation and distribution). Figure 9.1 shows how to determine how to account for emissions from transportation and distribution of sold products. Companies may use either the fuel-based, distance-based or spend-based method.

Activity data needed

The major difference between calculating upstream and downstream emissions of transportation is likely to be the availability and quality of activity data. Transportation data may be easier to obtain from upstream suppliers than from downstream customers and transportation companies. Therefore, companies may need to use the distance-based method to calculate downstream transportation emissions.

If the actual transportation distances are not known, the reporting company may estimate downstream distances by using a combination of:

- Government, academic, or industry publications
- Online maps and calculators
- Published port-to-port travel distances.

Emission factors needed

- See emission factors guidance for category 4 (Upstream transportation and distribution).

Data collection guidance

The UK government produces average freight distances for the economy's main categories of goods (see http://www.dft.gov.uk/pgr/statistics/datatablespublications/freight/). This database may be used in the absence of purchaser-specific or region-specific data.

A list of life cycle databases is provided on the GHG Protocol website (http://www.ghgprotocol.org/Third-Party-Databases). Additional databases may be added periodically, so continue to check the website.

Calculating emissions from distribution (downstream)

The emissions from downstream distribution should follow the calculation methods described in category 4 (Upstream transportation and distribution). Companies may use either the site-specific method or the average-data method. For the reasons outlined above, companies are more likely to apply the average-data method.

Example [9.1] Calculating emissions from downstream transportation

Company A sells timber to furniture Company B, which manufactures the timber into furniture, which it sells retail. Company A collects information on the mass of timber sold to Company B and estimates the downstream transport distances of the following:

- From point of sale to Company B (if not paid for by Company A)
- From Company B's manufacturing facility to retail distribution centers
- From retail distribution centers to retail outlets.

The data is summarized in the table below:

Purchaser	Mass of goods sold (tonnes)	Total downstream distance transported (km)	Transport mode or vehicle type	Emission factor (kg CO_2e/tonne-km)
B	4	2,000	Truck (rigid, >3.5-7.5t)	0.2

Note: the activity data and emissions factors are illustrative only, and do not refer to actual data.

emissions from downstream transport:

∑ (quantity of goods sold (tonnes) × distance travelled in transport legs (km)
× emission factor of transport mode or vehicle type (kg CO_2e/tonne-km))
= 4 × 2,000 × 0.2 = 1,600 kg CO_2e

10

Category 10: Processing of Sold Products

Category description

Category 10 includes emissions from processing of sold intermediate products by third parties (e.g., manufacturers) subsequent to sale by the reporting company. Intermediate products are products that require further processing, transformation, or inclusion in another product before use (see box 5.3 of the* Scope 3 Standard*), and therefore result in emissions from processing subsequent to sale by the reporting company and before use by the end consumer. Emissions from processing should be allocated to the intermediate product.

In certain cases, the eventual end use of sold intermediate products may be unknown. For example, a company that produces an intermediate product with many potential downstream applications, each of which has a different GHG emissions profile, may be unable to reasonably estimate the downstream emissions associated with these various end uses. See section 6.4 of the *Scope 3 Standard* for guidance in cases where downstream emissions associated with sold intermediate products are unknown.

See section 5.6 of the *Scope 3 Standard* for guidance on the applicability of category 10 to final products and intermediate products sold by the reporting company. A reporting company's scope 3 emissions from processing of sold intermediate products include the scope 1 and scope 2 emissions of downstream value chain partners (e.g., manufacturers).

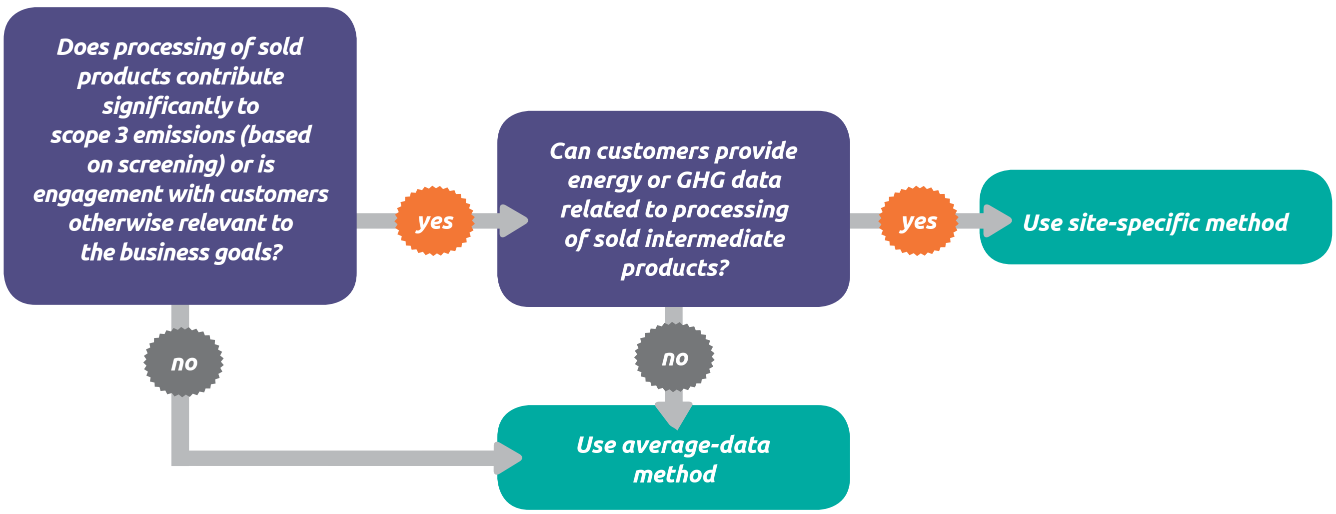
Calculating emissions from processing of sold products

Figure 10.1 gives a decision tree for selecting a calculation method for calculating scope 3 emissions from processing of sold products. Companies may use either of two methods:

- **Site-specific method**, which involves determining the amount of fuel and electricity used and the amount of waste generated from processing of sold intermediate products by the third party and applying the appropriate emission factors
- **Average-data method**, which involves estimating emissions for processing of sold intermediate products based on average secondary data, such as average emissions per process or per product.

Companies should choose a calculation method based on their business goals and their ability to collect data from processing of sold intermediate products by third parties. In many cases, collecting primary data from downstream value chain partners may be difficult. In such cases, companies should use the average-data method.

Figure [10.1] Decision tree for selecting a calculation method for emissions from processing of sold products



Site-specific method

To calculate emissions from the processing of sold products by third parties, companies should collect either of the following types of data from downstream value chain partners:

- Relevant activity data (e.g., fuel use, electricity use, refrigerant use, and waste) and relevant emission factors for each downstream process
- GHG emissions data for each downstream process calculated by downstream value chain partners.

If downstream processes involve intermediate goods and/or material inputs other than those sold by the reporting company, emissions should be allocated between intermediate product(s) sold by the reporting company and other intermediate products/material inputs. All processing steps through to the production of the final finished product should be accounted for within this category. For examples of allocating emissions, refer to chapter 8 of the *Scope 3 Standard*.

If data cannot be obtained from downstream third party partners, the average data method should be used.

Activity data needed

Companies should first collect data on the types and quantities of intermediate goods sold by the reporting company.

Companies should then collect either site-specific GHG emissions data provided by downstream value chain partners or site-specific activity data from downstream processes, including:

- Quantities of energy (including electricity and fuels) consumed in process(es)
- To the extent possible, mass of waste generated in process(es)
- If applicable, activity data related to non-combustion emissions (i.e., industrial process or fugitive emissions).

Emission factors needed

If site-specific activity data is collected, companies should also collect:

- Emission factors for fuels
- Emission factors for electricity
- To the extent possible, emission factors for waste outputs
- If applicable, emission factors related to non-combustion emissions (i.e., industrial process or fugitive emissions).

Data collection guidance

Companies should collect data on the types and mass of intermediate goods sold by the reporting company from internal records.

Companies should request either GHG emissions data or activity data from downstream processes from the downstream value chain partners that control those processes. Downstream partners can obtain this data from, for example:

- Internal IT systems
- Utility bills
- Purchase receipts
- Meter readings.

Data sources for emission factors include:

- The list of data sources provided on the GHG Protocol website (www.ghgprotocol.org/standards/scope-3-standard)
- Company or manufacturer developed emission factors
- Industry associations
- For activity data, emission factors, and formulas for process and fugitive emissions, see the GHG Protocol website (http://www.ghgprotocol.org/calculation-tools/all-tools) and the IPCC 2006 Guidelines (http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html).

Calculation formula [10.1] Site-specific method

CO_2e emissions from processing of sold intermediate products =

sum across fuel consumed in the processing of sold intermediate products:

∑ (quantity of fuel consumed (e.g., liter)

× life cycle emission factor for fuel source (e.g., kg CO_2e/liter))

+

sum across electricity consumed in the processing of sold intermediate products:

∑ (quantity of electricity consumed (e.g., kWh)

× life cycle emission factor for electricity (e.g., kg CO_2e/kWh))

+

sum across refrigerants used in the processing of sold intermediate products:

∑ (quantity of refrigerant leakage (kg) × Global Warming Potential for refrigerant (kg CO_2e/kg))

+

sum across process emissions released in the processing of sold intermediate products

+

to the extent possible, sum across waste generated in the in the processing of sold intermediate products:

∑ (mass of waste output (kg) × emission factor for waste activity (kg CO_2e/kg))

Example [10.1] Calculating emissions from processing of sold products using the site-specific method

Company A, which produces plastic resin, is an exclusive supplier to Company B, which produces plastic handles for consumer goods. Company A collects information from Company B regarding the fuel and electricity used and waste outputs of processing the resin into handles. The information is summarized in the tables below:

Fuel and electricity consumed	Amount (kWh)	Emission factor (kg CO_2e/kWh)
Natural Gas	3,500	0.2
Electricity	2,000	0.5

Waste	Amount (kg)	Emission factor (kg CO_2e/kg waste)
Waste products	50	0.5

Note: The activity data and emissions factors are illustrative only, and do not refer to actual data.

Emissions are calculated by multiplying activity data by respective emission factors, as follows:

emissions from fuel consumed:

∑ (quantity of fuel consumed (e.g., liter) × emission factor for fuel source (e.g., kg CO_2e/liter))

= 3,500 × 0.2

= 700 kg CO_2e

emissions from electricity consumed:

∑ (quantity of electricity consumed (e.g., kWh) × emission factor for electricity (e.g., kg CO_2e/kWh))

= 2,000 × 0.5

= 1,000 kg CO_2e

emissions from waste output:

∑ (mass of waste output (kg) × emission factor for waste activity (kg CO_2e/kg))

= 50 × 0.5

= 25 kg CO_2e

total emissions from processing of sold intermediate products

= emissions from fuel + emissions from electricity + emissions from waste

= 700 + 1,000 + 25

= 1,725 kg CO_2e

Average data method

In this method, companies collect data on the type of downstream process(es) involved in transforming or processing sold intermediate products into final products and apply relevant industry average emission factors to determine emissions. The method should be used when it is not possible to collect data from downstream value chain partners.

If the downstream processes use multiple types of inputs, companies should allocate emissions to the intermediate product sold by the reporting company. See chapter 8 of the *Scope 3 Standard* for guidance on allocation.

Activity data needed

For each type of sold intermediate product, companies should collect data on:

- The process(es) involved in transforming or processing sold intermediate products into an usable state final product, subsequent to sale by the reporting company
- Information needed for allocation (e.g., mass, economic value).

Emission factors needed

Companies should collect:

- Average emission factors for processing stages required to transform the sold intermediate product into a final product, expressed in units of emissions (e.g., CO_2, CH_4, N_2O) per unit of product (e.g., kg CO_2/kg of final product).

Care should be taken when selecting secondary data sources to understand the boundaries of the data and whether any additional calculation is required to avoid double counting.

Data collection guidance

Data sources for activity data include:

- Purchasing records
- Internal data systems
- Industry-average data from associations or databases.

Data sources for emission factors include:

- Life cycle databases
- The GHG Protocol website (http://www.ghgprotocol.org/calculation-tools/all-tools)
- Companies or manufacturers
- Industry associations.

Calculation resources include:

- GHG Protocol Calculation Tool, "Stationary Combustion GHG Emissions Calculation Tool. Version 2.0. June 2009," developed by World Resources Institute, available at http://www.ghgprotocol.org/calculation-tools/all-tools
- Defra GHG Conversion Factors, developed by the UK Department of Environment, Food and Rural Affairs (Defra), available at www.defra.gov.uk/environment/business/reporting/conversion-factors.htm.

Calculation formula [10.2] Average-data method

CO_2e emissions from processing of sold intermediate products =

sum across intermediate products:

∑ (mass of sold intermediate product (kg)

× emission factor of processing of sold products (kg CO_2e/kg of final product))

Example [10.2] Calculating emissions from processing of sold products using the average data method

Company E is a producer of sugar and an exclusive supplier to Company F, which makes candy. Company F confirms with Company E that after sugar is purchased, there are further processes before the final candy product is produced. Company E collects industry average emission factors for the relevant processes. The information is summarized in the table below:

Process	*Mass of sold intermediate product (kg)*	*Emission factor of processing stages (kg CO_2e/kg)*
Candy mixing, cooking, molding, cooling, wrapping, and packaging	1,000	1.5

Note: the activity data and emissions factors are illustrative only, and do not refer to actual data.

emissions from candy mixing and cooking process:

∑ (mass of sold intermediate product

× emission factor of processing stages (kg CO_2e/kg of final product))

= 1,000 × 1.5 = 1,500 kg CO_2e

11

Category 11: Use of Sold Products

Category description

This category includes emissions from the use of goods and services sold by the reporting company in the reporting year. A reporting company's scope 3 emissions from use of sold products include the scope 1 and scope 2 emissions of end users. End users include both consumers and business customers that use final products.

The Scope 3 Standard divides emissions from the use of sold products into two types (see also table 11.1):

- Direct use-phase emissions
- Indirect use-phase emissions.

In category 11, companies are required to include direct use-phase emissions of sold products. Companies may also account for indirect use-phase emissions of sold products, and should do so when indirect use-phase emissions are expected to be significant. See table 11.1 for descriptions and examples of direct and indirect use-phase emissions.

Category 11 includes the total expected lifetime emissions from all relevant products sold in the reporting year across the company's product portfolio. (Refer to chapter 5.4 of the *Scope 3 Standard* for more information on the time boundary of scope 3 categories.) See box 11.1 in this chapter for an example of reporting product lifetime emissions and box 11.2 for guidance related to product lifetime and durability. The GHG Protocol Product Standard provides information on accounting for life cycle GHG emissions from individual products.

Companies may optionally include emissions associated with maintenance of sold products during use.

See section 5.6 of the *Scope 3 Standard* for guidance on the applicability of category 11 to final products and intermediate products sold by the reporting company.

Table [11.1] Emissions from use of sold products

Type of Emissions	*Product Type*	*Examples*
Direct use-phase emissions (*required*)	Products that directly consume energy (fuels or electricity) during use	Automobiles, aircraft, engines, motors, power plants, buildings, appliances, electronics, lighting, data centers, web-based software
	Fuels and feedstocks	Petroleum products, natural gas, coal, biofuels, and crude oil
	Greenhouse gases and products that contain or form greenhouse gases that are emitted during use	CO_2, CH_4, N_2O, HFCs, PFCs, SF_6, refrigeration and air-conditioning equipment, industrial gases, fire extinguishers, fertilizers
Indirect use-phase emissions (*optional*)	Products that indirectly consume energy (fuels or electricity) during use	Apparel (requires washing and drying), food (requires cooking and refrigeration), pots and pans (require heating), and soaps and detergents (require heated water)

Source: Table 5.8 from the *Scope 3 Standard.*

Calculating emissions from category 11 typically requires product design specifications and assumptions about how consumers use products (e.g., use profiles, assumed product lifetimes). Companies are required to report a description of the methodologies and assumptions used to calculate emissions (see chapter 11 of the *Scope 3 Standard*).

Where relevant, companies should report additional information on product performance when reporting scope 3 emissions to provide additional transparency on steps companies are taking to reduce GHG emissions from sold products. Such information may include GHG intensity metrics, energy intensity metrics, and annual emissions from the use of sold products (see section 11.3 of the *Scope 3 Standard*). See section 9.3 of the *Scope 3 Standard* for guidance on recalculating base year emissions when methodologies or assumptions related to category 11 change over time.

Any claims of avoided emissions related to a company's sold products must be reported separately from the company's scope 1, scope 2, and scope 3 inventories. (For more information, see section 9.5 of the *Scope 3 Standard*)

Box [11.1] Example of reporting product lifetime emissions

An automaker sells 1 million cars in 2010. Each car has an expected lifetime of 10 years. The company reports the anticipated use-phase emissions of the 1 million cars it sold in 2010 over their 10-year expected lifetime. The company also reports corporate average fuel economy (km per liter) and corporate average emissions (kg CO_2e/km) as relevant emissions-intensity metrics.

Source: Box 5.7 from the *Scope 3 Standard.*

Box [11.2] Product lifetime and durability

Because the scope 3 inventory accounts for total lifetime emissions of sold products, companies that produce more durable products with longer lifetimes could appear to be penalized because, as product lifetimes increase, scope 3 emissions increase, assuming all else is constant. To reduce the potential for emissions data to be misinterpreted, companies should also report relevant information such as product lifetimes and emissions intensity metrics to demonstrate product performance over time. Relevant emissions intensity metrics may include annual emissions per product, energy efficiency per product, emissions per hour of use, emissions per kilometer driven, emissions per functional unit, etc.

Source: Box 5.8 from the *Scope 3 Standard.*

This section provides guidance of the following:

- What should be included in the emissions from use of sold products
- Guidance on what to include in a use profile
- Reporting guidance
- Guidance on how to assess uncertainty on the product's use profile.

Calculating emissions from use of sold products

This guidance provides calculation methods to calculate a company's:

- Direct use-phase emissions
- Indirect use-phase emissions.

Calculation methods for direct use-phase emissions

Companies should first determine in which categories their products belong. The following products have direct-use phase emissions:

- **Products that directly consume energy (fuels or electricity) during use:** involves breaking down the use phase, measuring emissions per product, and aggregating emissions
- **Fuels and feedstocks:** involves collecting fuel use data and multiplying them by representative fuel emission factors
- **Greenhouse gases and products that contain or form greenhouse gases that are emitted during use**: involves collecting data on the GHG contained in the product and multiplying them by the percent of GHGs released and GHG emission factors.

If a company sells a large selection of products, or if the use phase of multiple products is similar, it may choose to group similar products and use average statistics for a typical product in the product group. For example, a fast-moving consumer goods company selling carbonated drinks may decide to group products by packaging types and treat all products within that group with the same use profile.

Calculation method for direct use-phase emissions from products that directly consume energy (fuels or electricity) during use

In this method, the company multiplies the lifetime number of uses of each product by the amount sold and an emission factor per use. Companies should then aggregate use-phase emissions of all products.

Activity data needed

- Total lifetime expected uses of product(s)
- Quantities of products sold
- Fuel used per use of product
- Electricity consumption per use of product
- Refrigerant leakage per use of product.

Emission factors needed

- Life cycle emission factors for fuels
- Life cycle emission factors for electricity
- Global warming potential of refrigerants.

Data collection guidance

- Data sources for activity data include:
- Internal data systems
- Sales records
- Surveys
- Industry associations.

Data sources for emission factors include:

- The GHG Protocol website (www.ghgprotocol.org)
- Life cycle databases
- Company or supplier developed emission factors
- Industry associations.

It is important to consider the region where products are used, especially if the product consumes electricity because electricity grid emission factors can vary significantly. If its product is used globally, a company may consider using a global average electricity emission factor but estimating product use at a more granular level (either regional or national) and applying regional or national electricity grid emission factors would result in more accurate emissions estimates for this category. Scenario uncertainty can also be helpful here.

Calculation formula [11.1] Direct use-phase emissions from products that directly consume energy (fuels or electricity) during use

CO_2e emissions from use of sold products =

sum across fuels consumed from use of products:

∑ (total lifetime expected uses of product × number sold in reporting period × fuel consumed per use (kWh) × emission factor for fuel (kg CO_2e/kWh))

+

sum across electricity consumed from use of products:

∑ (total lifetime expected uses of product × number sold in reporting period × electricity consumed per use (kWh) × emission factor for electricity (kg CO_2e/kWh))

+

sum across refrigerant leakage from use of products:

∑ (total lifetime expected uses of product × number sold in reporting period × refrigerant leakage per use (kg) × global warming potential (kg CO_2e/kg))

Example [11.1] Calculating direct use-phase emissions from products that directly consume energy (fuels or electricity) during use

Company A is a manufacturer of electrical appliances such as washing machines and irons. It collects sales records of quantities sold as well as average lifetime uses for each of its products. It sources data on electricity consumed per use from industry reports and electricity emission factors from government data. The results are summarized in the table below:

Product	*Total uses over lifetime*	*Number sold*	*Electricity consumed per use (kWh)*	*Electricity emission factor (kg CO_2e/kWh)*
Washing machine X100	1,000	11,500	1.3	0.5
Washing machine X200	1,100	1,900	1.5	0.5
Iron Y123	2,000	20,000	0.2	0.5

Note: The activity data and emissions factors are illustrative only, and do not refer to actual data.

Example [11.1] Calculating direct use-phase emissions from products that directly consume energy (fuels or electricity) during use (continued)

Emissions for each product are calculated using the following formula:

$\sum$ (total lifetime expected uses of product × number sold in reporting period × electricity consumed per use (kWh) × emission factor for electricity (kg CO_2e/kWh))

Washing machine X100:
= 1,000 × 11,500 × 1.3 × 0.5 = 7,475,000 kg CO_2e

Washing machine X200:
= 1,100 × 1,900 × 1.5 × 0.5 = 1,567,500 kg CO_2e

Iron Y123:
= 2,000 × 20,000 × 0.2 × 0.5 = 4,000,000 kg CO_2e

total emissions from use of sold products
= emissions from X100 + emissions from X200 + emissions from Y123
= 7,475,000 + 1,567,500 + 4,000,000 = 13,042,500 kg CO_2e

Calculation method for direct use-phase emissions from fuels and feedstocks

Feedstock refers to starting materials that are used to make fuels, power and/or products. These may include biomass for producing power, crops for producing biofuels, or crude oil for producing plastic products. If the reporting company is a producer of fuels and/or feedstocks, the use-phase emissions are calculated by multiplying the quantities of fuels/feedstocks by the combustion emission factors for the fuels/feedstocks. If the feedstock is not combusted during the use phase, no emissions should be calculated.

Note that only the combustion emissions should be reported in this category, not the upstream emissions associated with the feedstock/fuel. This method avoids double counting as the upstream emissions associated with the production of the feedstock/fuel were already included in the reporting company's scope 1 and scope 2, as well as other scope 3 categories.

Activity data needed

- Total quantities of fuels/feedstocks sold.

Emission factors needed

- Combustion emission factors of fuel/feedstock.

Data collection guidance

Combustion emission factors for fuel/feedstock are well documented by many internationally recognized sources such as the IPCC Fourth Assessment Report and those factors included in the GHG Protocol calculation tools. In practice, the emissions vary between applications and countries based on the following:

- **Technology**: the completeness of combustion may vary from application to application
- **Exact fuel mix**: the precise fuel mix may vary from region to region and company to company; for example, the types of aromatic hydrocarbon mixed with gasoline may alter the combustion emissions.

Because of this variation companies should use the most representative emission factors for their fuel.

Calculation formula 11.2: Direct use-phase emissions from combusted fuels and feedstocks

CO_2e emissions from fuel =

sum across fuels/feedstocks:

∑ (total quantity of fuel/feedstock sold (e.g., kWh)

× combustion emission factor for fuel/feedstock (e.g., kg CO_2e/kWh))

Calculation method for direct use-phase emissions from greenhouse gases and products that contain or form greenhouse gases that are emitted during use

Some products may contain GHGs which are emitted during use or at the end of the product's useful life (e.g. products that contain refrigerents).

If the reporting company is a producer of products containing GHGs, use-phase emissions are calculated by multiplying the quantities of products sold by the percentage of GHGs released per unit of GHG contained in the product and by the global warming potential (GWP) of the greenhouse gases released.

Activity data needed

- Total quantities of products sold
- Quantities of GHGs contained per product
- Percentage of GHGs released throughout the lifetime of the product.

Emission factors needed

- GWP of the GHGs contained in the product, expressed in units of carbon dioxide per unit kilogram of the GHG (e.g., 25 kg CO_2e/kg)

Note: If different GHGs are released by the product, the total carbon dioxide equivalent should be reported and the breakdown of GHGs (e.g., CO_2, CH_4, N_2O) may be reported separately (see chapter 8 of the *Scope 3 Standard*).

The company should first account for all the different types of GHGs contained in a product, then aggregate for all products. If the use phase of a product is likely to be similar for multiple products, companies may group similar products.

Calculation formula [11.3] Direct use-phase emissions from greenhouse gases and products that contain or form greenhouse gases that are emitted during use

CO_2e emissions from greenhouse gases and products that contain or form greenhouse gases that are emitted during use =

sum across GHGs released in a product or product group:

∑ (GHG contained per product × Total Number of products sold × % of GHG released during lifetime use of product × GWP of the GHG)

then:

sum across products or product groups:

∑ (use phase emissions from product or product group 1,2,3…)

Note: if the % released is unknown 100% should be assumed.

Calculation methods for indirect use-phase emissions

Calculation method for indirect use-phase emissions from products that indirectly consume energy (fuels or electricity) during use

For products that indirectly consume energy or emit GHGs (see table 11.1), the reporting company should calculate emissions by creating or obtaining a typical use-phase profile over the lifetime of the product and multiplying by relevant emission factors.

Activity data needed

- Average number of uses over lifetime of product
- Average use scenarios (e.g., weighted average of scenarios)
- Fuel consumed in use scenarios
- Electricity consumed in use scenarios
- Refrigerant leakage in use scenarios
- GHGs emitted indirectly in use scenarios.

Emission factors needed

- Combustion emission factors of fuels and electricity.

Ideally agreement should be reached by a sector (e.g., industry associations and trade bodies) on common rules for use-phase assumptions. These assumptions can then be verified by an independent third party to improve consistency and comparability.

The emission factors applied should be representative of the geography of where the product is sold as well as the reporting year.

Data collection guidance

The generation of a typical use phase may be difficult because the same product may consume more or less energy depending on the conditions in which it is used. For example, a potato may be roasted, boiled, or microwaved, each cooking method using a different amount of energy and thus producing different levels of emissions.

Therefore, it is important to generate a use profile that is representative of use scenarios over the lifetime of the product by the intended consumer population. These may come from sources such as:

- Industry recognized benchmark testing specifications
- Product category rules
- Previous emissions studies
- Consumer studies.

Companies may choose to identify several different use-phase scenarios for a product and create a weighted average based upon actual activity.

Calculation formula [11.4] Indirect use-phase emissions from products that indirectly consume energy (fuels or electricity) during use

Indirect use-phase CO_2e emissions of products =

sum across fuels consumed from use scenarios:

∑ (total lifetime expected uses of product × % of total lifetime uses using this scenario × number sold in reporting period × fuel consumed per use in this scenario (e.g., kWh) × emission factor for fuel (e.g., kg CO_2e/kWh))

\+

sum across electricity consumed from use scenarios:

∑ (total lifetime expected uses of product × % of total lifetime uses using this scenario × number sold in reporting period × electricity consumed per use in this scenario (kWh) × emission factor for electricity (kg CO_2e/kWh))

\+

sum across refrigerant leakage from use scenarios:

∑ (total lifetime expected uses of product × % of total lifetime uses using this scenario × number sold in reporting period × refrigerant leakage per use in this scenario (kg) × emission factor for refrigerant (kg CO_2e/kg))

\+

sum across GHG emitted indirectly from use scenarios:

∑ (total lifetime expected uses of product × % of total lifetime uses using this scenario × number sold in reporting period × GHG emitted indirectly (kg) × GWP of the GHG)

Example [11.2] Calculating indirect use-phase emissions from products that indirectly consume energy (fuels or electricity) during use

Company A produces laundry soap, which indirectly entails consumption of electricity during the use phase. Company A collects data from consumer journals regarding the average consumer behavior in washing clothes and obtains average electricity emission factors from life cycle databases. The data is summarized in the table below:

Usage temperature setting	Lifetime uses per product (washes)	Consumers using temperature setting (percent)	Products sold	Electricity consumed per use (kWh)	Emission factor (kg CO_2e/kWh)
30°C cotton wash	1,000	20	2,000	0.40	0.5
40°C cotton wash		40		0.50	0.5
90°C cotton wash		40		1.20	0.5

Note: The activity data and emissions factors are illustrative only, and do not refer to actual data.

emissions for each use phase scenario is calculated as follows:
∑ (total lifetime expected uses of product × % of total lifetime uses using this scenario × number sold in reporting period × electricity consumed per use in this scenario (kWh) × emission factor for electricity (kg CO_2e/kWh))

30°C cotton wash: 1,000 × 0.2 × 2,000 × 0.4 × 0.5 = 80,000 kg CO_2e

40°C cotton wash: 1,000 × 0.4 × 2,000 × 0.5 × 0.5 = 200,000 kg CO_2e

90°C cotton wash: 1,000 × 0.4 × 2,000 × 1.2 × 0.5 = 480,000 kg CO_2e

total emissions from use of sold products
= emissions from 30°C + emissions from 40°C + emissions from 90°C
= 80,000 + 200,000 + 480,000 = 760,000 kg CO_2e

Calculation method for sold intermediate products

When a company sells an intermediate product that directly emits GHGs in its use phase, it is required to account for direct use-phase emissions of the intermediate product by the end user, (i.e., emissions resulting from: the use of the sold intermediate product that directly consumes fuel or electricity during use; fuels and feedstocks; GHGs released during product use). Companies may optionally include the indirect use-phase emissions of sold intermediate products.

In certain cases, the eventual end use of sold intermediate products may be unknown. For example, a company may produce an intermediate product with many potential downstream applications, each of which has a different GHG emissions profile and be unable to reasonably estimate the downstream emissions associated with the various possible end uses. In such a case, companies may disclose and justify the exclusion of all downstream emissions related to sold intermediate products. For more information, see section 6.4 of the *Scope 3 Standard* (Accounting for downstream emissions).

Activity data needed

- Type(s) of final product(s) produced from reporting company's intermediate product(s)
- Percentage of reporting company's intermediate product sales going to each type of final product
- Activity data required to calculate the use-phase emission of the final product will be the same as described previously in this chapter.

Emission factors needed

- Depending on the type of final product, emission factors required will be the same as described earlier in this chapter.

Calculation formula [11.5] Use-phase emissions from sold intermediate products

Use-phase CO_2e emissions of sold intermediate products =

sum across sold intermediate products total use phase emissions:

∑ (total intermediate products sold × total lifetime uses of final sold product × emissions per use of sold intermediate product (kg CO_2e/use))

Example [11.3] Calculating use-phase emissions from sold intermediate products

Company A manufactures engines used in airplanes. It sold 10 engines to an airplane manufacturer.

Number of engines sold	*Weight of each airplane (tonnes)*	*Weight of each engine (tonnes)*	*Total lifetime uses of final products (km flown by airplane)*	*Emissions per use of final product (kg CO_2e/km flown)*
10	500	20	300,000	0.3

Note: The activity data and emissions factors are illustrative only, and do not refer to actual data

Company A works out the direct use-phase emissions of its sold engines as follows:

total use phase emissions = ∑ (total intermediate products sold

× total lifetime uses of final sold product

× emissions per use of sold intermediate product (kg CO_2e/use)

× (weight of engine / weight of airplane))

$$= (10 \times 300{,}000 \times 0.3 \times (\frac{20}{500})) = 36{,}000 \text{ kg } CO_2e$$

In this example, physical allocation is most suitable. The allocation is based on the weight of the engine as a proportion of the total weight of the airplane. For allocation rules refer to section 8 of the *Scope 3 Standard*.

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Category 12: End-of-Life Treatment of Sold Products

Category description

Category 12 includes emissions from the waste disposal and treatment of products sold by the reporting company (in the reporting year) at the end of their life. This category includes the total expected end-of-life emissions from all products sold in the reporting year. (See section 5.4 of the Scope 3 Standard *for more information on the time boundary of scope 3 categories.)*

End-of-life treatment methods (e.g., landfilling, incineration, and recycling) are described in category 5 (Waste generated in operations) and apply to both category 5 and category 12. Calculating emissions from category 12 requires assumptions about the end-of-life treatment methods used by consumers. Companies are required to report a description of the methodologies and assumptions used to calculate emissions (see chapter 11 of the *Scope 3 Standard*).

For sold intermediate products, companies should account for the emissions from disposing of the intermediate product at the end of its life, not the final product.

Calculating emissions from end-of-life treatment of sold products

The emissions from downstream end-of-life treatment of sold products should follow the calculation methods in category 5 (Waste generated in operations), with the difference that instead of collecting data on total mass of waste generated in operations, companies should collect data on total mass of sold products (and packaging) from the point of sale by the reporting company through the end of life after use by consumers.

The major difference between calculating upstream and downstream emissions of waste treatment is likely to be the availability and quality of waste activity data. Whereas the reporting company is likely have specific waste type and waste treatment data from its own operations, this information is likely to be more difficult to obtain for sold products. Although the reporting company may know the product's components, it may not know how the waste-disposal behavior of consumers and retailers varies across geographic regions.

If the reporting company sells intermediate products, it is required to account for emissions from disposing of the sold intermediate products at the end of their life.

Activity data needed

Companies should collect:

- Total mass of sold products and packaging from the point of sale by the reporting company to the end-of-life after consumer use (e.g., packaging used to transport products through to the point of retail and any packaging that is disposed of prior to the end-of-life of the final product
- Proportion of this waste being treated by different methods (e.g., percent landfilled, incinerated, recycled).

Emission factors needed

Companies should collect:

- Average waste-treatment specific-emission factors based on all waste treatment types.

Data collection guidance

When collecting data on total waste produced, the reporting company should collect data on the waste type(s) and amounts after it sells the products through to the end-of-life disposal by consumers. This data should include any packaging and product waste. For food and drink items, companies should refer to average proportion of food/drinks wasted. In many cases, total waste will be equal to the total products sold in reporting year. However, if the product is actually consumed (e.g., food and drink) the total waste is likely to be lower, and in other cases, such as products combusted to generate energy, could even be zero.

When collecting data on the proportion of waste treated by different methods, companies may refer to:

- Company's own research and internal data on how its products are treated after consumption
- Specific government directives on waste treatment of certain products (e.g., the European Union's "Waste Electrical and Electronic Equipment Directive")
- Industry associations or organizations that have conducted research into consumer disposal patterns of specific products
- Average data on waste treatment from the point that the products are sold by the reporting company through to the end of life after consumer use.

Calculation resources include:

- The European Union publishes data on average end-of-life treatment scenarios of different product groups in EU member countries (see http://epp.eurostat.ec.europa.eu/portal/page/portal/waste/introduction/)
- The U.S. Environmental Protection Agency also publishes data on waste generation, recycling, and disposal statistics, available at: http://www.epa.gov/osw/nonhaz/municipal/msw99.htm
- Waste Resources and Action Programme (WRAP) publishes average food and drinks waste as a proportion of purchased amount in the UK economy, which may be used in the absence of product-specific data (see http://www.wrap.org.uk/retail_supply_chain/research_tools/research/report_household.html).

Calculation formula [12.1] Waste-type-specific method

CO_2e emissions from end-of-life treatment of sold products =

sum across waste treatment methods:

∑ (total mass of sold products and packaging from point of sale to end of life after consumer use (kg)
× % of total waste being treated by waste treatment method
× emission factor of waste treatment method (kg CO_2e/kg))

Example [12.1] Calculating emissions from the end-of-life treatment of sold products

Company A sells paper that is laminated in a way that does not allow recycling. In the reporting period, Company A sold 10,000 tonnes of product. The company conducts consumer research to understand the disposal methods used by end consumers. The company also collects data for emission factors associated with each of the disposal methods for laminated paper products from a life cycle assessment database:

Mass of waste after consumer use (kg)	Waste treatment	Proportion of waste produced (percent)	Emission factor of waste treatment method (kg CO_2e/kg)
10,000	Landfill	90	0.3
	Incinerated	10	1.0
	Recycled	0	0.0

Note: The activity data and emissions factors are illustrative only, and do not refer to actual data.

∑ (total mass of sold products at end of life after consumer use (kg)
× % of total waste being treated by waste treatment method
× emission factor of waste treatment method (kg CO_2e/kg))
= (10,000 × 90% × 0.3) + (10,000 × 10% × 1) + (10,000 × 0% × 0) = 3,700 kg CO_2e

13

Category 13: Downstream Leased Assets

Category description

This category includes emissions from the operation of assets that are owned by the reporting company (acting as lessor) and leased to other entities in the reporting year that are not already included in scope 1 or scope 2. This category is applicable to lessors (i.e., companies that receive payments from lessees). Companies that operate leased assets (i.e., lessees) should refer to category 8 (Upstream leased assets).

Leased assets may be included in a company's scope 1 or scope 2 inventory depending on the type of lease and the consolidation approach the company uses to define its organizational boundaries. (See section 5.2 of the *Scope 3 Standard* for more information.) If the reporting company leases an asset for only part of the reporting year, the reporting company should account for emissions from the portion of the year that the asset was leased. See Appendix A of the *Scope 3 Standard* for more information on accounting for emissions from leased assets.

In some cases, companies may not find value in distinguishing between products sold to customers (accounted for in category 11) and products leased to customers (accounted for in category 13). A company may account for products leased to customers in the same way it accounts for products sold to customers (i.e., by accounting for the total expected lifetime emissions from all relevant products leased to other entities in the reporting year). Companies should report emissions from leased products in category 11 (Use of sold products), rather than category 13 (Downstream leased assets) and avoid double counting between categories.

A reporting company's scope 3 emissions from downstream leased assets include the scope 1 and scope 2 emissions of lessees (depending on the lessee's consolidation approach).

Calculating emissions from leased assets

Downstream leased assets differ from upstream leased assets in that the leased assets are owned by the reporting company. The availability and access to information depends on the type of asset leased. For example, a company that leases vehicles may need to request fuel or mileage data from lessees in order to calculate emissions.

The calculation methods for upstream and downstream leased assets do not differ. For guidance on calculating emissions from category 13 (Downstream leased assets), refer to the guidance for category 8 (Upstream leased assets).

Companies requesting scope 1 and scope 2 data from lessees using the asset-specific method in category 8 (Upstream leased assets) may need to request additional information from the lessee in order to properly allocate emissions to the reporting company's leased assets. The lessee's scope 1 and scope 2 emissions data maybe aggregated, as with buildings without sub-metering. The reporting company may need to allocate these emissions in order to calculate emissions from this category. For guidance on collecting data and allocating emissions, refer to chapter 7 and chapter 8 of the *Scope 3 Standard*.

Example [13.1] Calculating the emissions from downstream leased assets

Company C (lessor) leases out a factory (factory 1) to Company D. Company D (lessee) knows its aggregated corporate scope 1 and scope 2 emissions of both factory 1 and a separate unit it operates, Factory 2. For company C to determine emissions associated with factory 1, it must allocate total emissions from both factories. It chooses to allocate based on physical allocation (i.e., floor space). The floor space of factory 1 is 5,000 m^2 and factory 2 is 10,000 m^2.

The data is summarized in the table below:

	Combined scope 1 and scope 2 emissions (kg CO_2e)	***Floor space (m^2)***
Factory 1	9,000	5,000
Factory 2		10,000

Note: The activity data and emissions factors are illustrative only, and do not refer to actual data

The emissions of company C's (lessor) downstream leased asset is calculated as follows:

$$\sum \text{scope 1 and scope 2 emissions of lessee (kg CO2e)}$$

$$\times \frac{\text{physical area of the leased asset (e.g., area, volume)}}{\text{total physical area of lessor assets (e.g., area, volume)}}$$

$$= 9{,}000 \times (5{,}000 / 15{,}000) = 3{,}000 \text{ kg } CO_2e$$

14

Category 14: Franchises

Category description

Category 14 includes emissions from the operation of franchises not included in scope 1 or scope 2. A franchise is a business operating under a license to sell or distribute another company's goods or services within a certain location. This category is applicable to franchisors (i.e., companies that grant licenses to other entities to sell or distribute its goods or services in return for payments, such as royalties for the use of trademarks and other services). Franchisors should account for emissions that occur from the operation of franchises (i.e., the scope 1 and scope 2 emissions of franchisees) in this category.

Franchisees (i.e., companies that operate franchises and pay fees to a franchisor) should include emissions from operations under their control in this category if they have not included those emissions in scope 1 and scope 2 due to their choice of consolidation approach. Franchisees may optionally report upstream scope 3 emissions associated with the franchisor's operations (i.e., the scope 1 and scope 2 emissions of the franchisor) in category 1 (Purchased goods and services).

Calculating emissions from franchises

Companies may use either of two methods to calculate emissions from franchises:

- **Franchise-specific method**, which involves collecting site-specific activity data or scope 1 and scope 2 emissions data from franchisees
- **Average-data method**, which involves estimating emissions for each franchise, or groups of franchises, based on average statistics, such as average emissions per franchise type or floor space.

Franchise-specific method

The franchise-specific method involves collecting scope 1 and scope 2 emissions from franchisees. If franchisees have conducted corporate scope 1 and scope 2 GHG inventory report(s), the data can be applied immediately. If such reports are not available, site-specific fuel and energy data from individual franchises should be collected. The reporting company should determine whether the franchisee delivers business solely for the reporting company (i.e., franchisor), and if not, the franchisee or the reporting company should allocate the emissions accordingly. Guidance on allocation is provided in chapter 8 of the *Scope 3 Standard*.

If significant upstream emissions result from the purchase of goods and services by franchisees, the franchisor developing the scope 3 inventory should include these emissions in this category. For example, a large fast-food franchise should account for the upstream emissions associated with the beef purchased by its franchise restaurants.

Activity data needed

Companies should collect data on either:

- Scope 1, scope 2, and (optionally) scope 3 emissions data from franchisees
- Site-specific fuel use, electricity use, and process and fugitive emissions activity data if applicable.

Emission factors needed

If collecting fuel and energy data, companies should also collect:

- Site- or regionally-specific emission factors for energy sources (e.g., electricity and fuels) per unit of consumption (e.g., kg CO_2e/kWh for electricity, kg CO_2e/liter for diesel)
- Emission factors of process emissions and fugitive emissions (e.g., refrigeration and air conditioning)
- Upstream emission factors.

Data collection guidance

- Data sources for activity data include:
- Public GHG inventory reports accessible through GHG reporting programs
- Utility bills
- Purchase records
- Meter readings
- Internal IT systems.

Data sources for emission factors include:

- The GHG Protocol websites (http://www.ghgprotocol.org/calculation-tools/all-tools and http://www.ghgprotocol.org/standards/scope-3-standard)
- Company-specific emission factors
- Industry associations
- Government agencies (e.g., Defra provides emission factors for the United Kingdom)
- For activity data, emission factors, and formulas for process and fugitive emissions, see the GHG Protocol website (http://www.ghgprotocol.org/calculation-tools/all-tools) and the IPCC 2006 Guidelines (http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html).

Calculation formula [14.1] Franchise-specific method

CO_2e emissions from franchises =
sum across franchises: $\sum$ (scope 1 emissions + scope 2 emissions of each franchise (kg CO_2e))

To calculate scope 3 emissions from franchises, aggregate the scope 1 and scope 2 emissions of all franchises, using the formula above.

Franchises that operate in a portion of a building where energy use is not separately sub-metered may estimate energy consumed using the franchise's share of the building's total floor space and total building energy use, following this formula:

Calculation formula [14.2] Allocating emissions from franchise buildings that are not sub-metered

CO_2e emissions allocated to franchise =

energy use from franchise (kWh)

$$= \frac{\text{franchise's area (m}^2\text{)}}{\text{building's total area (m}^2\text{)} \times \text{building's occupancy rate (e.g., 0.75)}} \times \text{building's total energy use (kWh)}$$

Using Samples

If a company has a large number of individual franchises, it may not be practical to collect data from each franchise. Therefore, companies may use appropriate sampling techniques when collecting data to represent all franchises from a representative sample of franchises. See Appendix A for more information on sampling.

Companies may also choose to categorize franchises into similar groups for data collection. The grouping strategy should group franchises with similar anticipated emissions intensities. Below is a non-exclusive list of possible ways to group franchises:

- Location, (e.g., country – particularly if electricity emission factors differ significantly among countries)
- Building type (e.g., free-standing buildings; leased shop space in shopping centres; shop-front at base of a larger city building)
- Floor space
- Financial turnover
- Product volume
- Customer numbers
- Distinctive characteristics (e.g., gyms with saunas, hotels with pools).

Calculation formula [14.3] Extrapolating emissions from sample groups

CO_2e emissions from franchises =

Step 1: aggregation of franchise emissions per group:

$$\text{total emissions from sampled franchises within group} \times \frac{\text{total number of franchises within group}}{\text{number of franchises sampled within group}}$$

Step 2: aggregation of total franchise emissions across all groups:

$$\sum \text{total scope 1 and scope 2 emissions from each asset group}$$

Companies that extrapolate from a representative sample within a franchise group should use the formula 14.2 to calculate emissions from sampled franchises within a group, then apply the formula in Step 1 above to estimate emissions for a franchise group. Companies should then use the formula in Step 2 above to aggregate franchise groups to the company's total emissions from franchises.

Example [14.1] Calculating the emissions from franchises using the franchise-specific method

Company A has multiple franchisees that operate restaurants. Company A requests the total scope 1 and scope 2 emissions of each of the franchisees:

Franchisee	Scope 1 emissions (kg CO_2e)	Scope 2 emissions (kg CO_2e)
1	100,000	20,000
2	25,000	10,000
3	30,000	10,000
4	90,000	30,000
5	30,000	10,000

Note: emissions are for illustrative purposes only, and do not refer to actual data.

company A can then perform the following calculation:

$$\sum \text{total scope 1 and scope 2 emissions from franchisees (kg } CO_2e)$$
$$= (100{,}000 + 20{,}000) + (25{,}000 + 10{,}000) + (30{,}000 + 10{,}000) + (90{,}000 + 30{,}000) + (30{,}000 + 10{,}000)$$
$$= 355{,}000 \text{ kg } CO_2e$$

Average-data method

The average-data approach involves estimating emissions for each franchise, or groups of franchises, based on average statistics, such as average emissions per building type, floor space, or franchise type. This approach should be used when purchase records, electricity bills, or meter readings of fuel or energy use are not available or applicable. Approaches include:

- Estimated emissions based on occupied floor space by building type
- Estimated emissions based on number and type of franchises.

Note that the average-data approach may be relatively inaccurate and limits the ability of companies to track performance of GHG reduction actions.

Activity data needed

Depending on the type of asset that is leased, companies may need to collect data on:

- Floor space of each franchise, by floor space
- Number of franchises, by building type
- Number of franchise assets that give rise to GHG emissions (e.g., company cars, trucks).

Emission factors needed

Depending on the type of asset that is leased companies may need to collect:

- Average emission factors by floor space, expressed in units of emissions per area per time period (e.g., kg CO_2e/m^2/day)
- Average emission factors by building type, expressed in units of emissions per building per time period (e.g., kg CO_2e/small office block/year)
- Emission factors by asset type, expressed in units of emissions per asset type per time period (e.g., kg CO_2e/car/year).

Data collection guidance

Data sources for emission factors include:

- Industry bodies (e.g., building industry)
- National statistics published by government agencies
- The U.S. Energy Information Administration dataset on average energy use by building type, Commercial Buildings Energy Consumption Survey, at: http://www.eia.doe.gov/emeu/cbecs.

Calculation formula [14.4] Average data method for leased buildings (if floor space data is available)

CO_2e emissions from franchises =

sum across building types:

∑ (total floor space of building type (m^2) × average emission factor for building type (kg CO_2e/m^2/year))

Calculation formula [14.5] **Average data method for other asset types or for leased buildings where floor space data is not available**

CO_2e emissions from franchises =

sum across building/asset types:
∑ (number of buildings or assets
× average emissions per building or asset type per year (kg CO_2e/building or asset type/year))

Example 14.2: **Calculating the emissions from franchises using the average data method**

Company A has multiple franchisees that operate a combination of food outlets and clothing outlets. To calculate emissions from franchises, Company A collects the following data:

Franchisee	*Type*	*Shop area (m^2)*	*Emission factor (kg CO_2e/m^2/year)*
1	Food outlet	100	30,000
2	Food outlet	150	30,000
3	Clothing outlet	400	10,000
4	Clothing outlet	700	10,000
5	Clothing outlet	500	10,000

Note that all emissions factors are used for illustrative purposes only

Company A can then perform the following calculation:

emissions from franchises
= ∑ (building or type × average emissions per building or asset type (kg CO_2e/building or asset type))
= (100 × 30,000) + (150 × 30,000) + (400 × 10,000) + (700 × 10,000) + (500 × 10,000)
= 23,500,000 kg CO_2e

15

Category 15: Investments

Category description

This category includes scope 3 emissions associated with the reporting company's investments in the reporting year, not already included in scope 1 or scope 2. This category is applicable to investors (i.e., companies that make an investment with the objective of making a profit) and companies that provide financial services. This category also applies to investors that are not profit driven (e.g. multilateral development banks), and the same calculation methods should be used. Investments are categorized as a downstream scope 3 category because providing capital or financing is a service provided by the reporting company.

Category 15 is designed primarily for private financial institutions (e.g., commercial banks), but is also relevant to public financial institutions (e.g., multilateral development banks, export credit agencies) and other entities with investments not included in scope 1 and scope 2.

Investments may be included in a company's scope 1 or scope 2 inventory depending on how the company defines its organizational boundaries. For example, companies that use the equity-share approach include emissions from equity investments in scope 1 and scope 2. Companies that use a control approach account only for those equity investments that are under the company's control in scope 1 and scope 2. Investments not included in the company's scope 1 or scope 2 emissions are included in scope 3, in this category. A reporting company's scope 3 emissions from investments are the scope 1 and scope 2 emissions of investees.

For purposes of GHG accounting, this standard divides financial investments into four types:

- Equity investments
- Debt investments
- Project finance
- Managed investments and client services.

Tables 15.1 and 15.2 provide GHG accounting guidance for each type of financial investment. Table 15.1 provides the types of investments required to be accounted for in this category. Table 15.2 identifies types of investments that companies may optionally report.

Emissions from investments should be allocated to the reporting company based on the reporting company's proportional share of investment in the investee. Because investment portfolios are dynamic and can change frequently throughout the reporting year, companies should identify investments by choosing a fixed point in time, such as December 31 of the reporting year, or by using a representative average over the course of the reporting year.

Table [15.1] Accounting for emissions from investments (required)

Financial investment/ service	*Description*	*GHG accounting approach (required)*
Equity investments	Equity investments made by the reporting company using the company's own capital and balance sheet, including: • Equity investments in **subsidiaries** (or group companies) where the reporting company has financial control (typically more than 50 percent ownership) • Equity investments in **associate companies** (or affiliated companies), where the reporting company has significant influence but not financial control (typically 20-50 percent ownership) • Equity investments in **joint ventures** (non-incorporated joint ventures/partnerships/ operations), where partners have joint financial control	In general, companies in the financial services sector should account for emissions from equity investments in scope 1 and scope 2 by using the equity share consolidation approach to obtain representative scope 1 and scope 2 inventories. If emissions from equity investments are not included in scope 1 or scope 2 (because the reporting company uses either the operational control or financial control consolidation approach and does not have control over the investee), account for *proportional scope 1 and scope 2 emissions* of equity investments* that occur in the reporting year in scope 3, category 15 (Investments).
	Equity investments made by the reporting company using the company's own capital and balance sheet, where the reporting company has **neither financial control nor significant influence** over the emitting entity (and typically has less than 20 percent ownership).	If not included in the reporting company's scope 1 and scope 2 inventories: Account for *proportional scope 1 and scope 2 emissions* of equity investments* that occur in the reporting year in scope 3, category 15 (Investments). Companies may establish a threshold (e.g., equity share of 1 percent) below which the company excludes equity investments from the inventory, if disclosed and justified.

Table [15.1] Accounting for emissions from investments (required) (continued)

<table>
<tr><th>Financial investment/ service</th><th>Description</th><th>GHG accounting approach (required)</th></tr>
<tr><td>Debt investments (with known use of proceeds)</td><td>Corporate debt holdings held in the reporting company’s portfolio, including corporate debt instruments (such as bonds or convertible bonds prior to conversion) or commercial loans, with known use of proceeds (i.e., where the use of proceeds is identified as going to a particular project, such as to build a specific power plant)</td><td rowspan="2">For each year during the term of the investment, companies should account for proportional scope 1 and scope 2 emissions of relevant projects* that occur in the reporting year in scope 3, category 15 (Investments). In addition, if the reporting company is an initial sponsor or lender of a project: Also account for the total projected lifetime scope 1 and scope 2 emissions of relevant projects* financed during the reporting year and report those emissions separately from scope 3.</td></tr>
<tr><td>Project finance</td><td>Long-term financing of projects (e.g., infrastructure and industrial projects) by the reporting company as either an equity investor (sponsor) or debt investor (financier)</td></tr>
</table>

Source: Table 5.9 from the *Scope 3 Standard*

Notes:
In the case of insurance companies, insurance premiums should be regarded as the insurance company’s own capital. Therefore equity investments made by insurance companies using insurance premiums are required to be reported (although companies may establish a threshold for equity investments). Accounting for emissions from insurance contracts is not required.

*Additional guidance on key concepts italicized is provided below.

- **Proportional emissions** from equity investments should be allocated to the investor based on the investor’s proportional share of equity in the investee. Proportional emissions from project finance and debt investments with known use of proceeds should be allocated to the investor based on the investor’s proportional share of total project costs (total equity plus debt). Companies may separately report additional metrics, such as total emissions of the investee, the investor’s proportional share of capital investment in the investee, etc.
- **Scope 1 and scope 2 emissions** include the direct (scope 1) emissions of the investee or project, as well as the indirect (scope 2) emissions from the generation of electricity consumed by the investee or project. If relevant, companies should also account for the scope 3 emissions of the investee or project. For example, if a financial institution provides equity or debt financing to a light bulb manufacturer, the financial institution is required to account for the proportional scope 1 and scope 2 emissions of the light bulb manufacturer (i.e., direct emissions during manufacturing and indirect emissions from electricity consumed during manufacturing). The financial institution should account for the scope 3 emissions of the light bulb producer (e.g., scope 3 emissions from consumer use of light bulbs sold by the manufacturer) when scope 3 emissions are significant compared to other source of emissions or otherwise relevant
- **Relevant projects** include those in GHG-intensive sectors (e.g., power generation), projects exceeding a specified emissions threshold (defined by the company or industry sector), or projects that meet other criteria developed by the company or industry sector. Companies should account for emissions from the GHG-emitting project financed by the reporting company, regardless of any financial intermediaries involved in the transaction.
- **Total projected lifetime emissions** are reported in the initial year the project is financed, not in subsequent years. If a project’s anticipated lifetime is uncertain, companies may report a range of likely values (e.g., for a coal-fired power plant, a company may report a range over a 30- to 60-year time period). Companies should report the assumptions used to estimate total anticipated lifetime emissions. If project financing occurs only once every few years, emissions from project finance may fluctuate significantly from year to year. Companies should provide appropriate context in the public report (e.g., by highlighting exceptional or non-recurring project financing). See section 5.4 of the *Scope 3 Standard* for more information on the time boundary of scope 3 categories.

Table [15.2] Accounting for emissions from investments (optional)

Financial investment/ service	*Description*	*GHG accounting approach (optional)*
Debt investments (without known use of proceeds)	General corporate purposes debt holdings (such as bonds or loans) held in the reporting company's portfolio where the use of proceeds is not specified	Companies may account for scope 1 and scope 2 emissions of the investee that occur in the reporting year in scope 3, category 15 (Investments)
Managed investments and client services	Investments managed by the reporting company on behalf of clients (using clients' capital[a]) or services provided by the reporting company to clients, including: • Investment and asset management (equity or fixed income funds managed on behalf of clients, using clients' capital) • Corporate underwriting and issuance for clients seeking equity or debt capital • Financial advisory services for clients seeking assistance with mergers and acquisitions or requesting other advisory services	Companies may account for emissions from managed investments and client services in scope 3, category 15 (Investments)
Other investments or financial services	All other types of investments, financial contracts, or financial services not included above (e.g., pension funds, retirement accounts, securitized products, insurance contracts, credit guarantees, financial guarantees, export credit insurance, credit default swaps, etc.)	Companies may account for emissions from other investments in scope 3, category 15 (Investments)

Source: Table 5.10 from the *Scope 3 Standard*

Notes:

a. Client's capital in this context refers to any capital that is not the reporting company's own capital, e.g., equity and fixed income fund managers investing the capital of the fund's investors.

This document provides detailed guidance only on the types of investments required to be reported in a scope 3 inventory (see table 15.1), it does not provide calculation guidance for many of the investment types that may be optionally reported. See table15.2. GHG Protocol may develop further guidance for calculating category 15 emissions. Check the GHG Protocol website for the latest guidance for accounting for GHG emissions associated with lending and investments: http://www.ghgprotocol.org/feature/financial-sector-guidance-corporate-value-chain-scope-3-accounting-and-reporting.

Because financial services companies may have a large number of investments, investments should be screened to prioritize investments that are likely to contribute most significantly to total GHG emissions. It is recommended that a screening, using the average-data methods described below, be carried out as a first step to calculating emissions from investments. This screening should enable financial institutions to identify their investments with the highest emissions and focus on these for primary data collection.

Calculating emissions from equity investments

It is a requirement of the *Scope 3 Standard* to report emissions from equity investments made by the reporting company using the company's own capital and balance sheet, including:

- Equity investments in **subsidiaries** (or group companies), where the reporting company has financial control (typically more than 50 percent ownership)
- Equity investments in **associate companies** (or affiliated companies), where the reporting company has significant influence but not financial control (typically 20-50 percent ownership)
- Equity investments in **joint ventures** (non-incorporated joint ventures/partnerships/ operations), where partners have joint financial control
- Equity investments where the reporting company has **neither financial control nor significant influence** over the emitting entity (and typically has less than 20 percent ownership). For these equity investments, companies may establish a threshold (e.g., equity share of 1 percent) below which the company excludes equity investments from the inventory, if disclosed and justified.

Companies should account for the proportional scope 1 and scope 2 emissions of the investments that occur in the reporting year. Proportional emissions from equity investments should be allocated to the investor based on the investor's proportional share of equity in the investee. Figure 15.1 shows a decision tree for selecting a calculation method for emissions from equity investments. Companies may use the following methods:

- **Investment-specific method**, which involves collecting scope 1 and scope 2 emissions from the investee company and allocating the emissions based upon the share of investment; or
- **Average-data method**, which involves using revenue data combined with EEIO data to estimate the scope 1 and scope 2 emissions from the investee company and allocating emissions based upon share of investment.

Companies should account for the proportional scope 1 and scope 2 emissions of the investments that occur in the reporting year. Companies should account for emissions from the GHG-emitting business activity, regardless of any financial intermediaries involved in the transaction. When scope 3 emissions are significant compared to other sources of emissions, investors should also account for the scope 3 emissions of the investee company. Calculating GHG emissions throughout the value chain of investee companies can help the investor understand and manage the climate change-related risks associated with his or her investments. If the majority of an investee company's emissions are associated with its value chain, then only focusing on scope 1 and scope 2 emissions will not provide the full picture of the company's risks. If the investor wants to understand the full GHG impact of the investee companies across their full value chain, for example, to identify hotspots for further engagement, including scope 3 may be more appropriate.

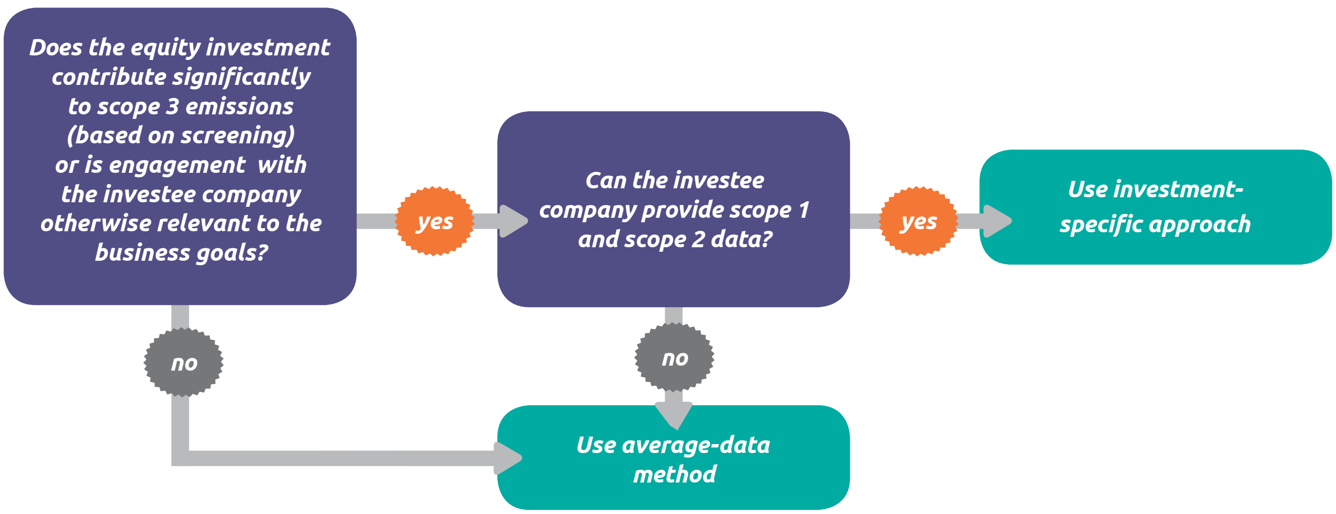
The GHG Protocol does not set a threshold above which scope 3 emissions should be included; instead, reporting companies should develop their own significance threshold based on their business goals. EEIO data can be used to quickly estimate the relative size of scope 3 emissions compared to scope 1 and scope 2 emissions for any sector.

Box [15.1] Applicability of calculation methods to managed investments (e.g. mutual funds)

Whether an organization is required to report on equity investments depends on whose capital is being invested. Asset owners are investing their own capital, so they are required to report emissions from equity investments (although they may establish a threshold, as described in table 15.1).

Asset managers investing clients' capital may optionally report on emissions from equity investments managed on behalf of clients (e.g., mutual funds). Emissions from these types of equity investments can be calculated using the methods described in this section, however it should be noted that mutual funds and other funds managed on behalf of clients are not the primary audience for the calculation methods described here and some of their specific issues have not been addressed, including the business goals relevant to a fund manager and the appropriate use of inventory results.

Figure [15.1] Decision tree for selecting a calculation method for emissions from equity investments



Investment-specific method

The investment-specific method involves collecting scope 1 and scope 2 emissions directly from investee companies and allocating these emissions based upon the proportion of the investment.

Activity data needed

Companies should collect:

- Scope 1 and scope 2 emissions of investee company
- The investor's proportional share of equity in the investee
- If significant, companies should also collect scope 3 emissions of the investee company (if investee companies are unable to provide scope 3 emissions data, scope 3 emissions may need to be estimated using the average-data method described in option 2).

Emission factors needed

If using the investment-specific method, the reporting company collects emissions data from investees, thus no emission factors are required.

Data collection guidance

Sources for data may include:

- GHG inventory reports of investee companies
- Financial records of the reporting company.

Calculation formula [15.1] Investment-specific method for calculating emissions from equity investments

Emissions from equity investments =

sum across equity investments:

∑ (scope 1 and scope 2 emissions of equity investment × share of equity (%))

Example [15.1] Calculating emissions from equity investments using the investment-specific method

Company A has two subsidiaries and two joint ventures. Company A used the control approach to determine its boundaries, so it did not include these subsidiaries and joint ventures in its scope 1 and scope 2 emissions inventory. Company A, therefore, includes emissions associated with these four investments in its scope 3 inventory. Company A collects scope 1 and scope 2 emissions associated with the investments from the GHG inventory reports of the investees, and obtains information on the share of the investments from its financial records.

Investment	*Investment type*	*Scope 1 and scope 2 emissions of investee company in reporting year (tonnes CO_2e)*	*Reporting company's share of equity (percent)*
1	Equity Investment in subsidiary	120,000	40
2	Equity Investment in subsidiary	200,000	15
3	Equity investment in joint venture	1,600,000	25
4	Equity investment in joint venture	60,000	25

Note: The data are illustrative only, and do not refer to actual data.

Example [15.1] Calculating emissions from equity investments using the investment-specific method (continued)

emissions from equity investments:

∑ (scope 1 and scope 2 emissions of equity investment × share of equity (%))

= (120,000 × 40%) + (200,000 × 15%) + (1,600,000 × 25%) + (60,000 × 25%)

= 48,000 + 30,000 + 400,000 + 15,000

= 493,000 tonnes CO_2e

Average-data method

The average-data method uses Environmentally-extended input-output (EEIO) data to estimate the scope 1 and scope 2 emissions associated with equity investments. The revenue of the investee company should be multiplied by the appropriate EEIO emission factor that is representative of the investee company's sector of the economy. For example, an apparel manufacturer should use an EEIO emission factor for apparel manufacturing. The reporting company should then use its proportional share of equity to allocate the estimated scope 1 and scope 2 emissions of the investee company.

Using EEIO data has limitations. EEIO databases contain average emission factors for each sector; therefore, when EEIO data is used to estimate emissions from investments, it is not possible to differentiate between investments within a particular sector. Using EEIO data can enable an investor to identify which sectors contribute most to its scope 3 investments category emissions, but investee-specific data would be required to identify the emissions hotspots within a particular sector. Another limitation is that the use of EEIO data will not enable the investor to track the GHG emissions of investee companies over time. See "Environmentally-extended input output (EEIO) data," in the Introduction for a broader discussion of the limitations of EEIO data.

Activity data needed

The reporting company should collect;

- Sector(s) the investee company operates in
- Revenue of investee company (if the investee company operates in more than one sector, the reporting company should collect data on the revenue for each sector in which it operates)
- The investor's proportional share of equity in the investee.

Emission factors needed

The reporting company should collect:

- EEIO emission factors for the sectors of the economy that the investments are related to (kg CO_2e/$ revenue).

The minimum boundary for reporting is the scope 1 and scope 2 emissions of the investee company. However, EEIO databases provide emission factors that include all upstream emissions. Therefore, if the investor is reporting only scope 1 and scope 2 emissions of the investee company, the EEIO emissions factor will need to be disaggregated to separate scope 1 and scope 2 emissions from all other upstream scope 3 emissions. Disaggregating the EEIO emission factor enables reporting companies to separate the scope 1 and scope 2 emissions from all other upstream scope 3 emissions, although sufficient information to do this may not be available. If disaggregation of the EEIO emission is not possible, reporting companies should use the full EEIO emission factor (i.e. include all upstream emissions). Reporting companies should clearly disclose the boundary used (either scope 1 and scope 2, or all upstream emissions).

When scope 3 emissions are significant compared with other sources of emissions, investors should also account for the scope 3 emissions of the investee company. Including upstream scope 3 emissions is simple when using EEIO databases because the EEIO emission factors include all upstream emissions.

Reporting companies should account for any significant changes in exchange rates and inflation rates over time. If possible, the EEIO data should be representative of the geographic region in which the investee company is located.

Data collection guidance

Data may be collected from the following sources:

- Revenue data and equity share data will be available from financial records of the reporting company and the investee company
- Emission factors are available from EEIO databases (a list of databases is provided on the GHG Protocol website (http://www.ghgprotocol.org/Third-Party-Databases). Additional databases may be added periodically, so continue to check the website.

Calculation formula [15.2] Average-data method for calculating emissions from equity investments

Emissions from equity investments =

sum across equity investments:

∑ ((investee company total revenue ($) × emission factor for investee's sector (kg CO_2e/$ revenue)) × share of equity (%))

Example [15.2] Calculating emissions from equity investments using the average-data method

Company A is an investment bank. It has a broad portfolio of proprietary equity investments in dozens of companies across geographic regions. Company A is unable to collect the scope 1 and scope 2 emissions of its investments because most investees have not completed GHG inventories. Company A decides to use the economic data method by grouping its investments by the sectors of the economy in which the investees are engaged. It collects EEIO emission factors for corresponding sectors by reference to EEIO databases. Company A obtains information on the share of the investments from its financial records and the financial reports of the investee companies.

The information is summarized as follows:

Investee company	Revenue of investee company ($)	Reporting company's share of equity (percent)	Investee company's sector(s) of operation	Investee company's revenue in sector (percent)	Scope 1 and scope 2 emission factor of sector (kg CO_2e/$ revenue)
1	3,000,000	5	Telecommunication	100	0.6
2	7,500,000	15	Pharmaceutical	100	0.5
3	1,150,000	20	Energy generation	100	3.0
4	5,500,000	10	Food and beverage	60	2.0
			Apparel	40	1.5

Note: The activity data and emissions factors are illustrative only and do not refer to actual data.

Emissions from equity investments:

∑ ((investee company revenue ($) × emission factor for investee's sector (kg CO_2e/$)) × share of equity)

= (3,000,000 × 0.60) × 0.05

+ (7,500,000 × 0.5) × 0.15

+ (1,150,000 × 3) × 0.20

+ ((5,500,000 × 0.6 × 2) + (5,500,000 × 0.4 × 1.5)) × 0.10

= 90,000 + 562,500 + 690,000 + 900,000 = 2,242,500 tonnes CO_2e

Calculating emissions from project finance and from debt investments with known use of proceeds

This section describes calculation methods used to calculate emissions from:

- Project finance
- Debt investments with known use of proceeds.

Project finance is defined in the *Scope 3 Standard* as long-term financing of projects (e.g., infrastructure and industrial projects) by the reporting company as either an equity investor (sponsor) or debt investor (financier). Corporate debt holdings with known use of proceeds are defined in the *Scope 3 Standard* as debt investments where the use of proceeds is identified as going to a particular project, such as to build a specific power plant.

For each year during the term of the investment, companies should account for proportional scope 1 and scope 2 emissions of relevant projects that occur in the reporting year. Proportional emissions from project finance and debt investments with known use of proceeds should be allocated to the investor based on the investor's proportional share of total project costs (total equity plus debt).

If scope 3 emissions of projects are significant compared to scope 1 and scope 2 emissions, investors should also account for proportional scope 3 emissions of projects that occur in the reporting year. This accounting could be particularly relevant for infrastructure projects like highways or bridges, where the scope 1 and scope 2 emissions during the operational phase of the projects are minimal compared with the scope 3 emissions from the use of the infrastructure (i.e., the emissions from the vehicles driving on the highway or bridge).

Figure 15.2 shows a decision tree for selecting a calculation method for emissions from project finance and debt investments with known use of proceeds. Companies may use the following methods:

- **Project-specific method**, which involves collecting scope 1 and scope 2 emissions for the relevant project(s) and allocating these emissions based on the investor's proportional share of total project costs (total equity plus debt)
- **Average-data method**, which involves using EEIO data to estimate the scope 1 and scope 2 emissions from the investee company and allocating emissions based on share of total project costs (total equity plus debt).

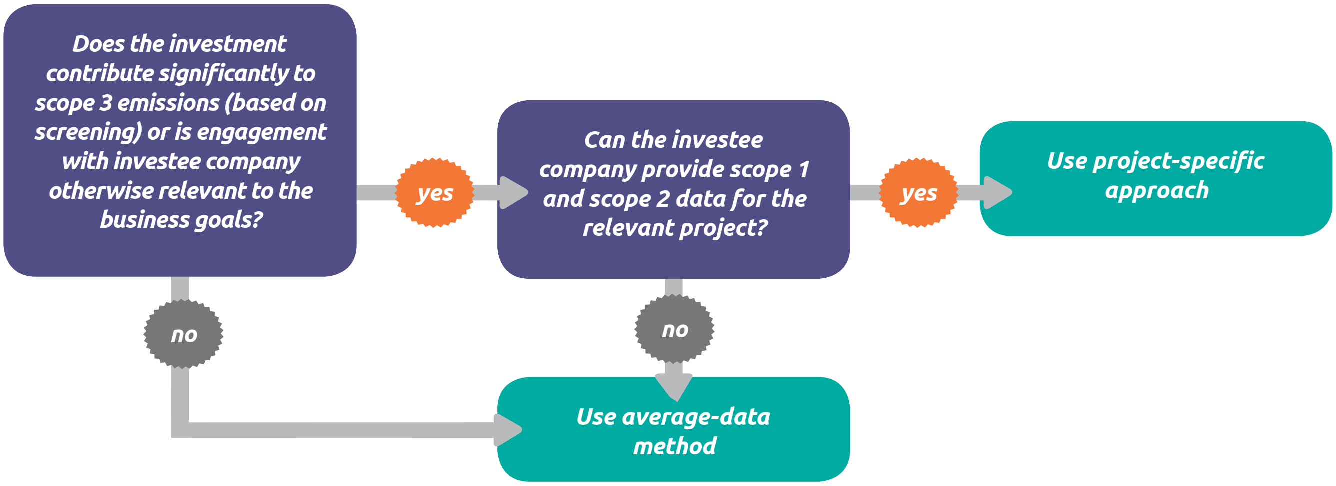
If the reporting company is an initial sponsor or lender of a project, it should also account for the total projected lifetime scope 1 and scope 2 emissions of relevant projects financed during the reporting year, and report those emissions separately from scope 3. The methods for calculating total projected lifetime emissions of projects are described in a subsequent section of this chapter - *Calculating total projected lifetime emissions from project finance and debt investments with known use of proceeds.*

Box [15.2] Calculating emissions from general corporate purposes debt investments

The *Scope 3 Standard* distinguishes debt investments with known use of proceeds from general corporate purposes debt holdings (see tables 15.1 and 15.2). General corporate purposes debt holdings (such as bonds or loans) **where the use of proceeds is not specified** can optionally be reported in a reporting company's scope 3 inventory.

Calculating emissions from debt investments **where the use of proceeds is not specified** should use the methods described for equity investments in section 15.1 (*Calculating emissions from equity investments*) except that the proportional share should be calculated based on the investor's proportional share of total equity **plus debt**. It should be noted that the calculation methodologies described in this guidance apply to long-term debt. Short-term debt (such as revolving credit facilities) would pose additional accounting challenges that are not addressed in this guidance.

Figure [15.2] Decision tree for selecting a calculation method for emissions from project finance and debt investments with known use of proceeds



Project-specific method

The project-specific method involves collecting scope 1 and scope 2 emissions directly from the investee company for the relevant project(s) and allocating these emissions based on the investor's proportional share of total project costs (total equity plus debt).

Activity data needed

Companies should collect:

- Scope 1 and scope 2 emissions that occur in the reporting year for the relevant projects
- The investor's proportional share of total project costs (total equity plus debt).

Emission factors needed

If using the project-specific method, the reporting company collects emissions data from investees, so no emission factors are required.

Data collection guidance

Sources for data may include:

- GHG inventory reports of investee companies
- Financial records of the reporting company
- A number countries and regions now have mandatory GHG reporting requirements for facilities over a certain size. These databases are usually available to the public.

Calculation formula [15.3] Project-specific method for calculating emissions from project finance and debt investments with known use of proceeds

CO_2e emissions from projects =

sum across projects:

∑ (scope 1 and scope 2 emissions of relevant project in the reporting year × share of total project costs (%))

Example [15.3] Calculating emissions from project finance and debt investments with known use of proceeds using the project-specific method

Company A is an investment bank. It makes debt investments in a number of utility and infrastructure companies for specific projects (such as building a new power plant). Company A collects scope 1 and scope 2 emissions data from the companies on the projects for which the investment bank provided debt capital.

The information is summarized as follows:

Investee company	*Scope 1 and scope 2 emissions of project in reporting year (tonnes CO_2e)*	*Value of debt investment ($)*	*Total project costs (total equity plus debt) ($)*	*Share of total project costs (percent)*
1	200,000	1,000,000	20,000,000	5.00
2	10,000	5,000,000	50,000,000	10.00
3	250,000	3,000,000	60,000,000	5.00
4	30,000	10,000,000	90,000,000	11.11

Note: The activity data and emissions factors are illustrative only, and do not refer to actual data.

emissions from debt investments with known use of proceeds
= (200,000 × 0.05) + (10,000 × 0.1) + (250,000 × 0.05) + (30,000 × 0.1111)
= 10,000 + 1,000 + 12,500 + 3,333 = 26,833 tonnes CO_2e

Average-data method

The average-data method uses environmentally-extended input output (EEIO) data to estimate the scope 1 and scope 2 emissions from projects. The project cost should be multiplied by appropriate emission factors that are representative of the sectors of the economy to which the project relates. For example, for a manufacturing facility construction project, an EEIO emission factor for “Construction of nonresidential manufacturing structures” should be used. The reporting company should then use its proportional share of total project costs (total equity plus debt) to allocate the project’s emissions.

Using EEIO data has limitations (see "*Environmentally-extended input output (EEIO) data*," in the Introduction for more information), so this option should only be used as a last resort if project-specific data is not available. Companies should clearly report on the methodology and assumptions used to calculate their emissions within this category.

Activity data needed

The reporting company should collect:

- Project costs in the reporting year (if the project is in the construction phase); or
- Revenue of the project (if the project is in the operational phase); and
- The investor's proportional share of total project costs (total equity plus debt).

Emission factors needed

The reporting company should collect one of the following:

- EEIO emission factors for the relevant construction sector that the investments are related to (kg CO_2e/$) (if the project is in the construction phase)
- EEIO emission factors for the relevant operating sector that the investments are related to (kg CO_2e/$) (if the project is in the operational phase).

Reporting companies should ensure that EEIO data is up-to-date and account for any significant changes in exchange rates and inflation rates over time. If possible, the EEIO data should be representative of the e geographic region where the project is located.

If a project (e.g., certain infrastructure projects) does not generate revenue during its operational phase then EEIO data cannot be used to estimate emissions. In these cases, other data or assumptions, such as industry or government studies of similar projects, can be used to estimate emissions from the operational phase.

Data collection guidance

Data may be collected from the following sources:

- Project cost and investment share data will be available from financial records of the reporting company and the investee company
- Emission factors from EEIO databases (a list of databases is provided on the GHG Protocol website http://www.ghgprotocol.org/Third-Party-Databases). Additional databases may be added periodically, so continue to check the website.

Calculation formula [15.4] Average-data method for calculating emissions from project finance and debt investments with known use of proceeds

Emissions from project finance and debt investments with known use proceeds =

sum across projects in the construction phase:
∑ ((project construction cost in the reporting year ($)
x emission factor of relevant construction sector (kg CO_2e/$ revenue))
x share of total project costs (%))

sum across projects in the operational phase:
∑ ((project revenue in the reporting year ($)
x emission factor of relevant operating sector (kg CO_2e/$ revenue))
x share of total project costs (%))

Example [15.4] Calculating emissions from project finance and debt investments with known use of proceeds using the average data method

Company A is an investment bank. It makes debt investments in a number of companies for specific projects (such as building a new power plant). This is the first year Company A has carried out a scope 3 inventory and due to time and resource constraints, it decided not to engage with the investee companies, but instead wants to use secondary data to estimate emissions. Company A states that it will consider engagement with investee companies in future years.

Company A collects data from its internal data management system. The information is summarized as follows:

Type of project	*Project phase*	*Project construction cost or project revenue in reporting year ($ million)*	*Relevant EEIO sector*	*EEIO emission factor (scope 1 and scope 2 emissions only) (tonnes CO_2e / $ millions)*	*Share of total project costs (value of debt investment / total equity plus debt) (percent)*
Bridge	Construction	20	Other non-residential structures	310	7
Hospital	Construction	8	Construction of non-residential commercial and health care structures	325	10
Paper manufacturing facility	Operation	3	Paper mills	500	5
Coal-fired power plant	Operation	15	Power generation and supply	9,000	5

Note: The activity data and emissions factors are illustrative only, and do not refer to actual data.

Example [15.4] Calculating emissions from project finance and debt investments with known use of proceeds using the average data method (continued)

emissions from debt investments with known use of proceeds

= ∑ ((project construction costs in the reporting year or project revenue in reporting year ($) × emission factor of sector (kg CO_2e/$)) x share of total project costs)

= ((20 x 310) x 0.07) + ((8 x 325) x 0.10) + ((3 x 500) x 0.05) + ((15 x 9,000) x 0.05)
= 434 + 260 + 75 + 6,750 = 7,519 tonnes CO_2e

Calculating total projected lifetime emissions from project finance and debt investments with known use of proceeds

If the reporting company is an initial sponsor or lender of a project, it should also account for the total projected lifetime scope 1 and scope 2 emissions of relevant projects financed during the reporting year, and report those emissions separately from scope 3. Accounting for the projected lifetime emissions reflects the longer term nature of these forms of investment. Accounting for total projected lifetime emissions is in addition to (and separate from) accounting for annual scope 1 and scope 2 emissions of projects for each year during the term of the investment (as described in the previous section Calculating emissions from project finance and from debt investments with known use of proceeds).

Total projected lifetime emissions are reported in the initial year the project is financed, not in subsequent years, and emissions should not be amortized or discounted. As it is required for companies to account for proportional scope 1 and scope 2 emissions of projects for each year during the term of the investment, reporting amortized projected lifetime emissions each year during the term of the investment in addition to annual scope 1 and scope 2 emissions would result in double counting. Once the project has been constructed and is operational, the lifetime emissions have been locked in, so it is in the initial stage of a project where total lifetime emissions should be taken into consideration. Companies should report the assumptions used to estimate total anticipated lifetime scope 1 and scope 2 emissions.

When scope 3 emissions of projects are significant compared to scope 1 and scope 2 emissions, investors should also account for total projected lifetime scope 3 emissions of projects. This could be particularly relevant for infrastructure projects like highways or bridges, where the scope 1 and scope 2 emissions of the projects during the operational phase are minimal compared to the scope 3 emissions from the use of the infrastructure (i.e., the emissions from the vehicles driving on the highway or bridge).

Any claims of avoided emissions related to a project must be reported separately from the company's scope 1, scope 2, and scope 3 inventories. (For more information, see section 9.5 of the *Scope 3 Standard*).

Calculating projected lifetime emissions typically requires making assumptions about the operation of the asset and its expected lifetime. The data needed to calculate expected emissions will depend on the type of project.

Companies should collect:

- Expected average annual emissions of project. For power plants for example, emissions can be derived from the plant's capacity and heat rate, the carbon content of the fuel, and projected capacity utilization
- Expected lifetime of project.

If there is uncertainty around a project's anticipated lifetime, companies may report a range of likely values (e.g., for a coal-fired power plant, a company may report a range of 30- to 60-years).

Calculation formula [15.4] Method for calculating projected total lifetime emissions from project finance and debt investments with known use of proceeds

Projected total lifetime emissions from project finance and debt investments with known use proceeds =

∑ ((projected annual emissions of project x projected lifetime of project) x share of total project costs)

Note that project total lifetime emissions are only required to be reported in the initial year the project is financed, so the share of total project costs (total equity plus debt) refers only to initial sponsors/lenders.

Example [15.5] Calculating projected total lifetime emissions from project finance and debt investments with known use of proceeds

Company A is an investment bank. In the reporting year, the bank project financed the construction of one power plant as an initial lender.

The information is summarized as follows:

Expected annual emissions (tonnes)	*Expected lifetime of project (years)*	*Proportional share of total project costs (total equity plus debt) (percent)*
7,000,000	30–60	15

Note: The data are illustrative only, and do not refer to actual data

Projected lifetime emissions of projects financed in the reporting year
= (projected annual emissions of project x projected lifetime of project) x share of total project costs

30 year lifetime: (7,000,000 x 30) x 0.15 = 31,500,000 tonnes CO_2e
60 year lifetime: (7,000,000 x 60) x 0.15 = 63,000,000 tonnes CO_2e

A

Appendix A: Sampling

A company needing to collect a large quantity of data for a particular scope 3 category may find it impractical or impossible to collect the data from each activity in the category. In such cases, companies may use appropriate sampling techniques to extrapolate data from a representative sample of activities within the category.

Companies may also choose to categorize activities into similar groups for data collection. This strategy should group activities with similar anticipated emissions intensities. For example:

- Companies with a large number of leased assets (Categories 8 and 13) or franchises (Category 14) may group buildings by building type or floor area and vehicles by vehicle type
- Companies with a large number of employees collecting data on employee commuting (Category 7) may wish to extrapolate data from a representative sample of employees
- Companies with a large number of distribution channels may use sampling when calculating the emissions associated with Categories 4 and 9 (Transportation and Distribution).

Companies should choose a sampling method that aligns with their business goals and document and justify their choice. The choice of sampling method will depend on factors including, but not limited to:

- Available resources
- Number of data points
- Expected level of homogeneity between samples
- Geographical spread of data points
- Ease of data collection
- Timeframe available.

Ultimately, the use of sampling and choice of a specific sampling method aims to optimize the trade-off between cost and accurately representing all emission sources in the scope 3 category. Companies may use a variety of sampling methods, as appropriate for each specific emissions activity.

Sampling methods

Sampling methods available to companies include, but are not limited to:

- Simple random sampling
- Systematic sampling
- Stratified sampling

Each approach is summarized below. Alternative methods for sampling may also be used.

Simple Random Sampling

Simple random sampling involves randomly selecting activities (i.e., a sample) from a larger set of activities (i.e., the entire population).

If the total number of activities from which a sample is selected is small, simple random sampling may be performed at its most basic level by selecting activities at random. If the total number of activities is large, for example with hundreds or thousands of activities, then random sampling is better performed by computer.

Advantages of simple random sampling include:

- With an appropriate sample size, simple random sampling creates a representative view of the entire population. (For example, if a company has fifty employees located within a close geographical area and wants to determine the average commuting distance, it may choose to collect data from ten randomly selected employees as a representative sample.)
- It is relatively straightforward to construct the sample.

Disadvantages of simple random sampling include:

- The sample size needed to generate appropriately representative results may be prohibitively large and cumbersome to sample. (For example, if a retail organization has thousands of stores in many countries, randomly selecting individual stores may result in a difficult and time-consuming data collection process.)
- It may not be possible to obtain a complete list of all activities from the sample size, which is a prerequisite for simple random sampling. (For example, if a distribution company wants to determine the average backhaul capacity of its trucks, it would have to list every journey before a random sample could be selected.)

Systematic Sampling

Systematic sampling involves randomly selecting the first item to sample and then selecting subsequent activities at regular intervals.

An appropriate sampling interval should be chosen so that the company achieves the desired sample size. For example, if a company sourced agricultural products from 100 farms but only wanted to sample 20 farms, an appropriate sampling interval would be every 5 farms. If the first farm to be sampled was picked as Farm 3, the company would subsequently sample from Farms 8, 13, 18, 23,…, 93, 98.

Calculation formula [A.1] Selecting an appropriate systematic sampling interval

Systematic sampling interval =
sampling interval = total population size / desired sample size

Advantages of systematic sampling include:

- Simple to implement
- The population is guaranteed to be evenly sampled without risk that the sample points are clustered together.

Disadvantages of systematic sampling include:

- If there is a periodic pattern in the population to be sampled, it could lead to biased sampling
- As with simple random sampling, it may not be possible to obtain a complete list of all activities in the population.

Stratified Sampling

Stratified sampling initially groups the population's activities into categories with similar characteristics. Random sampling is subsequently performed within these homogeneous groups.

The company should initially create population groups containing activities with characteristics likely to offer similar intensities of GHG emissions. Grouping variables could include location, size, building type, manufacturing technique, age, etc.

For example, if an agricultural produce company was assessing emissions from its farms, it may use the following variable to create initial groupings of all farms: high / low rainfall; smaller than 100 hectares / larger than 100 hectares; north-facing-hill / south-facing-hill / neither.

Stratified sampling is particularly useful when the variability in GHG emissions within groups is small, but the variability between groups is large.

Advantages of stratified sampling:

- Can lead to higher precision because there is less variability within the groups given that similar characteristics are grouped together.
- The necessary sample size can be reduced due to lower variability within groups, therefore saving time and money.
- Allows companies to draw insights into the source and level of emissions among different groups. This level of detail may be lost with simple random sampling.
- Different random sampling techniques may be employed for different groups as appropriate.

Disadvantages of stratified sampling:

- Identifying appropriate variables and forming sampling groups may be difficult and complex.

Sample Size

Determining sample size is fundamental to any sampling activity. The choice of sample size will be influenced by several factors, including the likely significance of GHG emissions from the sources in question, the size of the population, the variability of the emission sources, and the necessary degree of precision.

Determining sample size

There are several approaches to determining sample size. In particular, four alternative approaches may prove useful for companies:

- Using the sample size of a similar inventory
- Using online calculators
- Using published tables
- Using formulas.

Using the sample size of a similar inventory

Companies may refer to similar inventories for guidance on appropriate sample size and sampling technique. When using this approach, companies should justify the similarity and appropriateness for the comparison. Companies may refer to similar inventories that have been externally verified for guidance on appropriate sample size and sampling technique.

Using online calculators

Online calculators are a quick and easy way to assess sample size.

For example:

- http://www.research-advisors.com/tools/SampleSize.htm provides a downloadable spreadsheet to calculate necessary sample size with the ability to tailor the sampling criteria.
- http://www.surveysystem.com/sscalc.htm provides an interactive online calculator for sample size; however, the choices for confidence level are fixed.

Using published tables

Many published tables give the necessary sample size for a specific set of criteria. Such criteria include precision, confidence levels, and variability for a given population size.

Users should refer to standard statistics texts or search online for a table matching their specific sampling criteria.

Using formulas

Companies that want greater assurance for their choice of sample size may turn to established formulas. Formulas for the calculation of sample size are available in all standard statistics and sampling text books, as well as via the internet.

When applying sample size formulas, users may find it advantageous to seek the advice of a person with experience of statistics.

Level of accuracy

The level of accuracy is related to the sample size, sampling strategy, and the measurement system. Assuming a normal distribution, increasing the sample size is likely to reduce the sampling error using the relationship $v = \sqrt{n}$. In this relationship "v" represents the variability of the data values. It is important to recognize that all measurements contain some level of uncertainty. An estimate of the measurement uncertainty should be obtained, particularly for parts of the assessment that contribute significantly to the organization and/ or if subsequent investment decisions are made based on the measurement.

Confidence level

An estimate of the uncertainty, which should include both precision and bias from random error and systematic error respectively, will enable an interpretation of the measurement. For example, a level of uncertainty of ±5 percent would imply for an emissions estimate of 100 tonnes CO_2e, that the actual emissions lie somewhere between 95 and 105 tonnes CO_2e. The confidence level associated with the uncertainty normally corresponds to a 95 percent confidence level, that is, 2 standard deviations. For example, the true value lies in the range of 95 and 105 tonnes with 95 percent confidence.

Variability

Variability refers to the degree of difference between activities within the population. A population that is more heterogeneous (more variable) will require a larger sample size. A variability of 50 percent is the maximum level of variability in a population. Therefore, a variability assumption of 0.5 is often used as a conservative estimate.

B

Appendix B: Scenario uncertainty in calculating emissions from the use of sold products

Scenario uncertainty assessment (also known as sensitivity analysis) is a useful tool to understand how changes in the product's design, use, and disposal could impact inventory results. It can be thought of as the impact of potential situations other than the conditions and assumptions made in the product's inventory results and report.

Example [B.1] Scenario analysis: measuring uncertainty in calculating emissions from the use of sold products

Company A produces electric fans for residential consumers. The electric fan has a wattage of 300. Company data indicates that consumers use the electric fan an average of 40 days a year, with an average use of 6 hours/day for a total of 5 years of use before disposing of the fan.

To calculate use-phase emissions, the company made the following calculations:

total lifetime usage = 40 x 6 x 5 = 1,200 hours

CO_2e emissions per hour of use = wattage x electricity grid factor = 300 x 0.45 = 0.135 kg CO_2e/hour use

the company sold 1,000 units in the reporting year, so total use-phase emissions for the reporting company = 1,200 x 0.135 x 1,000 = 162,000 kg CO_2e = 162 tonnes CO_2e

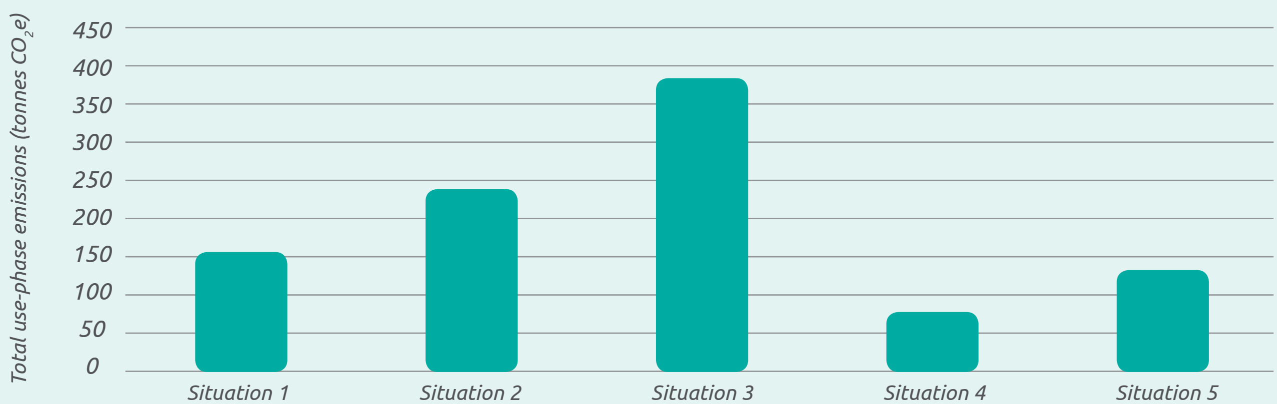
Example [B.1] Scenario analysis: measuring uncertainty in calculating emissions from the use of sold products (continued)

For both the reporting company and stakeholders, it may be valuable to understand how a change in the use pattern would change the inventory results. Company A has defined the average usage scenario in situation 1. However, based on research the company conducted, the number of days that the electric fan is used could range between 20 and 60 per year, and the lifespan of the fan could range from 5 to 8 years.

To understand the impacts of the use phase of the electric fan in these different scenarios, four hypothetical scenarios were developed based on the range of use days per year and the range of life span. Total use-phase emissions were then calculated for each scenario.

Situation	*Use days/year*	*Use hours/day*	*Use lifespan (years)*
1	40	6	5
2	60	6	5
3	60	6	8
4	20	6	5
5	20	6	8

Electric fan use-phase emissions under different use situations



As shown in the table and graph above, different scenarios show different use phase emissions. The scenario uncertainty analysis helps the reporting company ensure that the scenario used in the inventory is representative of the range of scenarios, and not the scenario with the lowest emissions.

If the scenario uncertainty shows a very large range in emissions, and if this range is significant relative to total scope 3 emissions, companies may choose to conduct more detailed analysis of the use profile of the product to more accurately calculate use-phase emissions and reduce the uncertainty.

C

Appendix C: Calculating emissions intensity metrics

The Scope 3 Standard states that companies may report emissions intensity metrics to avoid misinterpretation of emission results as more durable products with longer lifetimes would at first appear to have higher lifetime use-phase emissions.

To convert absolute emissions to an emissions intensity metric, companies should calculate emissions per a relevant unit of measure. Examples of emissions intensity metrics are given in table C.1.

Table [C.1] Examples of emissions intensity metrics using different units of measure

Product	*Emissions intensity metric*
Can of cola	kg CO_2e per 330ml can
Washing machine	kg CO_2e per wash
Television	kg CO_2e per hour of viewing
Car	kg CO_2e per kilometer driven

Calculation formula [C.1] Calculating emission intensity metrics

CO_2e emissions per functional unit of product =

number of units over lifetime of sold product:

$$\frac{\text{total lifetime emissions}}{\text{units per lifetime of products}}$$

The reporting company must first decide on the unit of measure to apply to the product. The emissions intensity metric is then calculated as shown in formula C.1 above.

Example [C.1] Calculating emission intensity metrics

Company A manufactures and sells washing machines. The company calculated their emissions from use of sold products (category 11) as 500,000 kg CO_2e.

Company A then decided to report an emissions intensity metric to give context to the use-phase emissions of its washing machines. An example of an intensity metric that could be used for washing machines is noted in example 11.2 (*Calculating indirect use-phase emissions from products that indirectly consume energy (fuels or electricity) during use*) – kg CO_2e per wash. Using this intensity metric, emissions are calculated as follows:

Number of units over lifetime of all products sold in the reporting year
= lifetime units per product × total number of products sold in reporting year
= 1,500 washes × 2,000 washing machines
= 3,000,000 washes over lifetime of all sold products

As stated above, the total emissions from use of Company A's sold products is 500,000 kg CO_2e. So the emissions intensity can be calculated as follows:

$$\text{emissions intensity metric} = \frac{\text{total lifetime emissions}}{\text{number of functional units performed over lifetime of sold products}}$$

$$= \frac{500{,}000}{3{,}000{,}000}$$

= 0.1667 kg CO_2e per wash

Appendix D: Calculation formula summary tables

Summary of calculation methods for category 1 (Purchased goods and services)

Method	*Calculation Formula*	*Activity Data Needed*	*Emission Factor Needed*
Supplier-specific method	**sum across purchased goods and services:** ∑ (quantities of good purchased (e.g., kg) × supplier-specific product emission factor of purchased good or service (e.g., kg CO_2e/kg))	• Quantities or units of goods or services purchased	• Supplier-specific emission factors for the purchased goods or services (e.g., if the supplier has conducted a reliable cradle-to-gate GHG inventory, product footprint or internal LCA report)
Hybrid method (where supplier-specific activity data is available for all activities associated with producing the purchased goods)	**sum across purchased goods and services:** ∑ scope 1 and 2 emissions of tier 1 supplier relating to purchased good or service (kg CO_2e) + **sum across material inputs of the purchased goods and services:** ∑ (mass or quantity of material inputs used by tier 1 supplier relating to purchased good or service (kg or unit) × cradle-to-gate emission factor for the material (kg CO_2e/kg or kg CO_2e/unit)) + **sum across transport of material inputs to tier 1 supplier:** ∑ (distance of transport of material inputs to tier 1 supplier (km) × mass or volume of material input (tonnes or TEUs) × cradle-to-gate emission factor for the vehicle type (kg CO_2e/tonne or TEU/km)) + **sum across waste outputs by tier 1 supplier relating to purchased goods and services:** ∑ (mass of waste from tier 1 supplier relating to the purchased good or service (kg) × emission factor for waste activity (kg CO_2e/kg)) + other emissions emitted in provision of the good or service as applicable	• Allocated scope 1 and 2 data (including emissions from electricity use and fuel use and any process and fugitive emissions) by supplier relating to the good or service purchased by the reporting company. For guidance on allocating emissions, refer to chapter 8 of the *Scope 3 Standard*. • Mass or quantity of material inputs (e.g., bill of materials) used by supplier to produce purchased goods • Mass or quantity of fuel inputs used by supplier to produce purchased goods • Distance from the origin of the raw material inputs to the supplier (the transport emissions from the supplier to the reporting company is calculated in category 4 so should not be included here) • Quantities of waste output by supplier to produce purchased goods • Other emissions emitted in provision of the purchased goods as applicable	Depending what activity data has been collected from the supplier, companies may need to collect: • Cradle-to-gate emission factors for materials used by tier 1 supplier to produce purchased goods (Note: these emission factors can either be supplier-specific emission factors provided by the supplier, or industry average emission factors sourced from a secondary database. In general, preference should be given to more specific and verified emission factors) • Life cycle emission factors for fuel used by incoming transport of input materials to tier 1 supplier • Emission factors for waste outputs by tier 1 supplier to produce purchased goods • Other emission factors as applicable (e.g., process emissions) • The secondary emission factors required will also depend on what data is available for the purchased good. Companies will need to collect either: • Cradle-to-gate emission factors of the purchased goods or services per unit of mass or unit of product (e.g., kg CO_2e/kg or kg CO_2e/hour spent); or • Cradle-to-gate emission factors of the purchased goods or services per unit of economic value (e.g., kg CO_2e/$)

Summary of calculation methods for category 1 (Purchased goods and services) (continued)

Method	*Calculation Formula*	*Activity Data Needed*	*Emission Factor Needed*
Hybrid method (where only allocated scope 1 and 2 emissions and waste data are available from supplier)	**sum across purchased goods and services:** ∑ scope 1 and scope 2 emissions of tier 1 supplier relating to purchased good or service (kg CO_2e) + ∑ (mass of waste from tier 1 supplier relating to the purchased good (kg) × emission factor for waste activity (kg CO_2e/kg)) + ∑ (mass or quantity of units of purchased good or service (kg) × emission factor of purchased good excluding scope 1, scope 2, and emissions from waste generated by producer (kg CO_2e/kg or unit or $))		
Average-data method	**sum across purchased goods and services:** ∑ (mass of purchased good or service (kg) × emission factor of purchased good or service per unit of mass (kg CO_2e/kg)) or ∑ (unit of purchased good or service (e.g., piece) × emission factor of purchased good or service per reference unit (e.g., kg CO_2e/piece))	• Mass or number of units of purchased goods or services for a given year (e.g., kg, hours spent, etc.)	• Cradle-to-gate emission factors of the purchased goods or services per unit of mass or unit of product (e.g., kg CO_2e/kg or kg CO_2e/hour spent)
Spend-based method	**sum across purchased goods and services:** ∑ (value of purchased good or service ($) × emission factor of purchased good or service per unit of economic value (kg CO_2e/$))	• Amount spent on purchased goods or services, by product type, using market values (e.g., dollars)	• Cradle-to-gate emission factors of the purchased goods or services per unit of economic value (e.g., kg CO_2e/$)

Summary of calculation methods for category 2 (Capital goods)

Method	Calculation Formula	Activity Data Needed	Emission Factor Needed
Supplier-specific method	**sum across capital goods:** ∑ (quantities of capital good purchased (e.g., kg) × supplier-specific product emission factor of capital good (e.g., kg CO_2e/kg))	• Quantities or units of capital goods purchased in the reporting year	• Supplier-specific emission factors for the capital goods (e.g., if the supplier has conducted a reliable cradle-to-gate GHG inventory, product footprint or internal LCA report)
Hybrid method (where supplier-specific activity data is available for all activities associated with producing the purchased goods)	**sum across capital goods:** ∑ scope 1 and 2 emissions of tier 1 supplier relating to capital good (kg CO_2e) + **sum across material inputs of the capital goods:** ∑ (mass or quantity of material inputs used by tier 1 supplier relating to capital good (kg or unit) × cradle-to-gate emission factor for the material (kg CO_2e/kg or kg CO_2e/unit)) + **sum across transport of material inputs to tier 1 supplier:** ∑ (distance of transport of material inputs to tier 1 supplier (km) × mass or volume of material input (tonnes or TEUs) × cradle-to-gate emission factor for the vehicle type (kg CO_2e/tonne or TEU/km)) + **sum across waste outputs by tier 1 supplier relating to capital goods:** ∑ (mass of waste from tier 1 supplier relating to the capital good (kg) × emission factor for waste activity (kg CO_2e/kg)) + other emissions emitted in provision of capital goods as applicable	• Allocated scope 1 and 2 data (including emissions from electricity use and fuel use and any process and fugitive emissions) by supplier relating to the capital good purchased by the reporting company. For guidance on allocating emissions, refer to chapter 8 of the *Scope 3 Standard*. • Mass or quantity of material inputs (e.g., bill of materials) used by supplier to produce capital goods • Mass or quantity of fuel inputs used by supplier to produce capital goods • Distance from the origin of the raw material inputs to the supplier (the transport emissions from the supplier to the reporting company is calculated in category 4 so should not be included here) • Quantities of waste output by supplier to produce capital goods • Other emissions emitted in provision of the capital goods as applicable	• Depending what activity data has been collected from the supplier, companies may need to collect: • Cradle-to-gate emission factors for materials used by tier 1 supplier to produce capital goods (Note: these emission factors can either be supplier-specific emission factors provided by the supplier, or industry average emission factors sourced from a secondary database. In general, preference should be given to more specific and verified emission factors) • Life cycle emission factors for fuel used by incoming transport of input materials to tier 1 supplier • Emission factors for waste outputs by tier 1 supplier to produce capital goods • Other emission factors as applicable (e.g., process emissions) • The secondary emission factors required will also depend on what data is available for the capital good. Companies will need to collect either: • Cradle-to-gate emission factors of the capital goods per unit of mass or unit of product (e.g., kg CO_2e/kg); or • Cradle-to-gate emission factors of the capital goods per unit of economic value (e.g., kg CO_2e/$)
Hybrid method (where only allocated scope 1 and 2 emissions and waste data are available from supplier)	**sum across capital goods:** ∑ scope 1 and scope 2 emissions of tier 1 supplier relating to capital good (kg CO_2e) + ∑ (mass of waste from tier 1 supplier relating to the capital good (kg) × emission factor for waste activity (kg CO_2e/kg)) + ∑ (mass or quantity of units of capital good (e.g., kg) × emission factor of capital good excluding scope 1, scope 2, and emissions from waste generated by producer (kg CO_2e/kg or unit or $))		
Average-data method	**sum across capital goods:** ∑ (mass of capital good (kg) × emission factor of capital good per unit of mass (kg CO_2e/kg)) or ∑ (unit of capital good (e.g., piece) × emission factor of capital good per reference unit (e.g., kg CO_2e/piece))	• Mass or number of units of capital goods for a given year (e.g., kg)	• Cradle-to-gate emission factors of the capital goods per unit of mass or unit of product (e.g., kg CO_2e/kg or kg CO_2e/hour spent)
Spend-based method	**sum across capital goods:** ∑ (value of capital good ($) × emission factor of capital good per unit of economic value (kg CO_2e/$))	• Amount spent on capital goods, by product type, using market values (e.g., $)	• Cradle-to-gate emission factors of the capital goods per unit of economic value (e.g., kg CO_2e/$)

Summary of Calculation Methods for Category 3 (Fuel- and energy-related activities not included in scope 1 or scope 2)

Method	*Calculation Formula*	*Activity Data Needed*	*Emission Factor Needed*
A. Upstream emissions of purchased fuels			
Supplier-specific or average-data method	**sum across each fuel type consumed:** ∑ (fuel consumed (e.g., kWh) × upstream fuel emission factor (kg CO_2e)/kWh)) **where:** upstream fuel emission factor = life cycle emission factor – combustion emission factor	Quantities and types of fuel consumed	Supplier-specific method • Fuel-provider-specific emission factors on extraction, production and transportation of fuels per unit of fuel consumed by the reporting company (e.g., kg CO_2e/kWh), by fuel type and country or region Average-data method • Average emission factors for upstream emissions per unit of consumption (e.g., kg CO_2e/kWh)
B. Upstream emissions of purchased electricity			
Supplier-specific or average-data method	**sum across suppliers, regions, or countries:** ∑ (electricity consumed (kWh) × upstream electricity emission factor (kgCO_2e)/kWh)) + (steam consumed (kWh) × upstream steam emission factor (kg CO_2e)/kWh)) + (heating consumed (kWh) × upstream heating emission factor (kg CO_2e)/kWh)) + (cooling consumed (kWh) × upstream cooling emission factor (kg CO_2e)/kWh)) **where:** upstream emission factor = life cycle emission factor – combustion emissions factor – T&D losses Note: T&D losses need to be subtracted only if they are included in the life cycle emission factor. Companies should check the emission factor to establish whether or not T&D losses have been taken into account.	Total quantities of electricity, steam, heating or cooling purchased and consumed per unit of consumption (e.g., MWh), broken down by supplier, grid region or country	Supplier-specific method • Utility-specific emission factors for extraction, production and transportation of fuels consumed per MWh of electricity, steam, heating or cooling generated Average-data method • Grid-region, country, or regional emission factors for extraction, production and transportation of fuels per unit of consumption (e.g., kg CO_2e/kWh) of electricity, steam, heating or cooling generated
C. T&D losses			
Supplier-specific or average-data method	**sum across suppliers, regions, or countries:** ∑ (electricity consumed (kWh) × electricity life cycle emission factor ((kg CO_2e)/kWh) × T&D loss rate (%)) + (steam consumed (kWh) × steam life cycle emission factor ((kg CO_2e)/kWh) × T&D loss rate (%)) + (heating consumed (kWh) × heating life cycle emission factor ((kg CO_2e)/kWh) × T&D loss rate (%)) + (cooling consumed (kWh) × cooling life cycle emission factor ((kg CO_2e)/kWh) × T&D loss rate (%))	• Electricity, steam, heating or cooling per unit of consumption (e.g., MWh), broken down by grid region or country; and/or • Scope 2 emissions data	Supplier-specific method • Utility-specific transmission & distribution loss rate (%), specific to grid where energy is generated and consumed Average-data method • Country average transmission & distribution loss rate (%) • Regional average transmission & distribution loss rate (%) • Global average transmission & distribution loss rate (%)

Summary of Calculation Methods for Category 3 (Fuel- and energy-related activities not included in scope 1 or scope 2) (continued)

Method	*Calculation Formula*	*Activity Data Needed*	*Emission Factor Needed*
D. Generation of purchased electricity that is sold to end users			
Supplier-specific or average-data method	**sum across suppliers, regions or countries:** ∑ (electricity purchased for resale (kWh) × electricity life cycle emission factor (kg CO_2e)/kWh)) + (steam purchased for resale (kWh) × steam life cycle emission factor (kg CO_2e)/kWh)) + (heating purchased for resale (kWh) × heating life cycle emission factor (kg CO_2e)/kWh)) + (cooling purchased for resale (kWh) × cooling life cycle emission factor (kg CO_2e)/kWh))	Quantities and specific source (e.g., generation unit) of electricity purchased and re-sold	Supplier-specific method • Specific emissions data for generation unit from which purchased power is generated Average-data method • Grid average rate for the origin of purchased power

Summary of Calculation Methods for Category 4 (Upstream transportation and distribution)

Method	*Calculation Formula*	*Activity Data Needed*	*Emission Factors Needed*
Calculating Emissions from Transportation			
Fuel-based method	**sum across fuel types:** ∑ (quantity of fuel consumed (liters) × emission factor for the fuel (e.g., kg CO_2e/liter)) + sum across grid regions: ∑ (quantity of electricity consumed (kWh) × emission factor for electricity grid (e.g., kg CO_2e/kWh)) + sum across refrigerant and air-conditioning types: ∑ (quantity of refrigerant leakage × global warming potential for the refrigerant (e.g., kg CO_2e)) **If fuel data is unavailable, companies may use the following two formulae to calculate quantities of fuel consumed:** **Calculating fuel use from fuel spend** sum across fuel types: $\sum \frac{\text{total fuel spend (e.g., \\$)}}{\text{average fuel price (e.g., \\$/liter)}}$ Calculating fuel use from distance travelled sum across transport steps: ∑ (total distance travelled (e.g., km) × fuel efficiency of vehicle (e.g., liters/km)) Allocated fuel use = $= \text{total fuel consumed (litres)} \times \left(\frac{\text{mass/volume of company's goods}}{\text{mass/volume of goods transported}} \right)$ Companies may optionally substitute mass of goods by volume with dimensional mass or chargeable mass where data is available to prove that the alternative method is more suitable. Dimensional mass is a calculated mass that takes into account packaging volume as well as the actual mass of the goods. Chargeable mass is the higher value of either the actual or the dimensional mass of the goods. **(Optional) CO_2e emissions from unladen backhaul =** **for each fuel type:** ∑ (quantity of fuel consumed from backhaul × emission factor for the fuel (e.g., kg CO_2e/liter)) **where:** quantity of fuel consumed from backhaul = average efficiency of vehicles unladen (l/km) × total distance travelled unladen	• Quantities of fuel (e.g., diesel, gasoline, jet fuel, biofuels, etc.) consumed; • Amount spent on fuel and average cost of fuel • Amount of refrigerant leakage; and If applicable: • Distance travelled; • Average fuel efficiency of the vehicle, expressed in units of liters of fuel consumed per tonne per kilometer transported; • Mass of purchased goods in the vehicle (tonnes) • Information on whether the products are refrigerated during transport	• Fuel emission factors, expressed in units of emissions per unit of energy consumed (e.g., kg CO_2e/liters, CO_2e/Btu, etc.) • For electric vehicles (if applicable), electricity emission factors, expressed in units of emissions per unit of electricity consumed (e.g., kg CO_2e/kWh) • Refrigerant leakage emission factors, expressed in units of emissions per unit of refrigerant leaked (e.g., kg CO_2e/kg leakage) Emission factors should include scope 1 and scope 2 emissions of the fuel and optionally include cradle-to-gate emissions.

Summary of Calculation Methods for Category 4 (Upstream transportation and distribution) (continued)

Method	*Calculation Formula*	*Activity Data Needed*	*Emission Factors Needed*
Distance-based method	**sum across transport modes and/or vehicle types:** ∑ (mass of goods purchased (tonnes or volume) × distance travelled in transport leg (km) × emission factor of transport mode or vehicle type (kg CO_2e/tonne or volume/km))	• Mass or volume of the products sold • Actual distances provided by transportation suppliers • Online maps or calculators; and/or • Published port-to-port travel distances	Emission factor by mode of transport (e.g., rail, air, etc) or vehicle types (e.g., articulated lorry, container vessel, etc), expressed in units of greenhouse gases (CO_2, CH_4, N_2O) per unit of mass (tonne) or volume (e.g., TEU) travelled (e.g., km)
Spend-based method	**sum across transport modes and/or vehicle types:** ∑ (amount spent on transportation by type ($) × relevant EEIO emission factors per unit of economic value (kg CO_2e/$))	• Amount spent on transportation by type (e.g. road, rail, air, barge), using market values (e.g., dollars).	• Cradle-to-gate emission factors of the transportation type per unit of economic value (e.g., kg CO_2e/$) • Where applicable, inflation data to convert market values between the year of the EEIO emissions factors and the year of the activity data.
Calculating Emissions from Distribution			
Site-specific method	**for each storage facility:** emissions of storage facility (kg CO_2e) = (fuel consumed (kWh) × fuel emission factor (kg CO_2e/kWh)) + (electricity consumed (kWh) × electricity emission factor (kg CO_2e)/kWh)) + (quantity of refrigerant leakage (kg) × global warming potential for the refrigerant (e.g., kg CO_2e)) **then, allocate emissions based on volume that company's products take within storage facility:** allocated emissions of storage facility $= \frac{\text{volume of reporting company's purchased goods (m}^3\text{)}}{\text{total volume of goods in storage facility (m}^3\text{)}}$ × emissions of storage facility (kg CO_2e) **finally, sum across all storage facilities:** ∑ allocated emissions of storage facility	• Site-specific fuel, electricity use; and • Site-specific refrigerant leakage • The average occupancy rate of the storage facility (i.e., average total volume of goods stored)	• Site or regionally specific emission factors for energy sources (e.g., electricity and fuels) per unit of consumption (e.g., kg CO_2e/kWh for electricity, kg CO_2e/liter for diesel); and • Refrigerant emission factors of fugitive and process emissions (kg HFC/kg of refrigerant leakage)

Summary of Calculation Methods for Category 4 (Upstream transportation and distribution) (continued)

Method	*Calculation Formula*	*Activity Data Needed*	*Emission Factors Needed*
Average-data method	**sum across storage facilities:** ∑ (volume of stored goods (m^3 or pallet or TEU) × average number of days stored (days) × emission factor for storage facility (kg CO_2e/m^3 or pallet or TEU/day))	• Companies should collect data based upon the throughput • Volume of purchased goods that are stored (e.g., m^2, m^3, pallet, TEU) or number of pallets needed to store purchased goods • Average number of days that goods are stored	Companies should collect data which allows the calculation of emissions per unit stored. This can be expressed in several different ways, including; • Emission factor per pallet stored in facility • Emission factor per m^2/m^3 stored in facility • Emission factor per TEU (twenty-foot equivalent unit) stored in facility

Summary of Calculation Methods for Category 5 (Waste generated in operations)

Method	Calculation Formula	Activity Data Needed	Emission Factors Needed
Supplier-specific method	**sum across waste treatment providers:** ∑ allocated scope 1 and 2 emissions of waste treatment company	• Allocated scope 1 and 2 emissions of waste-treatment company (allocated to the waste collected from the reporting company)	• If using the waste treatment company method, the reporting company collects emissions data from waste treatment companies, so no emission factors are required (the w company would have already used emission factors to calculate the emissions).
Waste-type-specific method	**sum across waste types:** ∑ (waste produced (tonnes or m^3) × waste type and waste treatment specific emission factor (kg CO_2e/tonne or m^3))	• Waste produced (e.g., tonne, m^3) and type of different waste generated in operations • For each waste type, specific waste treatment method applied (e.g., landfilled, incinerated, recycled, etc.)	• Waste type-specific and waste treatment-specific emission factors. The emission factors should include end-of-life processes only. • Emission factors may include emissions from transportation of waste.
Average-data method	**sum across waste treatment methods:** ∑ (total mass of waste (tonnes) × proportion of total waste being treated by waste treatment method × emission factor of waste treatment method (kg CO_2e/tonne))	• Total mass of waste generated in operations • Proportion of this waste being treated by different methods (e.g., % landfilled, incinerated, recycled, etc)	• Average waste treatment specific emission factors based upon all waste disposal types

Summary of Calculation Methods for Category 6 (Business travel)

Method	*Calculation Formula*	*Activity Data Needed*	*Emission Factor Needed*
Fuel-based method	**sum across fuel types:** ∑ (quantity of fuel consumed (liters) × emission factor for the fuel (e.g., kg CO_2e/liter)) + **sum across grid regions:** ∑ (quantity of electricity consumed (kWh) × emission factor for electricity grid (e.g., kg CO_2e/kWh)) + **sum across refrigerant and air-conditioning types:** ∑ (quantity of refrigerant leakage × global warming potential for the refrigerant (e.g., kg CO_2e)) **If fuel data is unavailable, companies may use the following two formulae to calculate quantities of fuel consumed:** **Calculating fuel use from fuel spend** **sum across fuel types:** $\sum \frac{\text{total fuel spend (e.g., \$)}}{\text{average fuel price (e.g., \$/liter)}}$ **Calculating fuel use from distance travelled** **sum across transport steps:** ∑ (total distance travelled (e.g., km) × fuel efficiency of vehicle (e.g., liters/km)) + **(optional)** ∑ (annual number of hotel nights (nights) × hotel emission factor (kg CO_2e/night))	• Quantities of fuel (e.g., diesel, gasoline, jet fuel, biofuels, etc.) consumed; • Amount spent on fuel and average cost of fuel • Fugitive emissions (e.g., refrigerant leakage); and If applicable: • Distance travelled; • Average fuel efficiency of the vehicle	• Life cycle fuel emission factors, expressed in units of emissions per unit of energy consumed (e.g., kg CO_2e/liters, kg CO_2e/Btu, etc.) • For electric vehicles (if applicable), electricity emission factors, expressed in units of emissions per unit of electricity consumed (e.g., kg CO_2e/kWh) • Fugitive emission factors, expressed in units of emissions per unit of fugitive emission (e.g., kg CO_2e/kg refrigerant leakage)
Distance-based method	**sum across vehicle types:** ∑ (distance travelled by vehicle type (vehicle-km or passenger-km) × vehicle specific emission factor (kg CO_2e/vehicle-km or kg CO_2e/passenger-km)) + **(optional)** ∑ (annual number of hotel nights (nights) × hotel emission factor (kg CO_2e/night))	• Total distance travelled by each mode of transport (air, train, bus, car, etc.) for all employees in the reporting year. • Countries of travel (since transportation emission factors vary by country) • Specific types of vehicles used for travel (since transportation emission factors vary by vehicle types) from transport providers	• Emission factors that represent kilograms of CO_2e emitted per kilometer or passenger-kilometer for each mode of transport (e.g., aircraft, rail, metro, bus, taxi, bus, etc.) • For electric vehicles (if applicable), electricity emission factors, expressed in units of emissions per kilometer or passenger-kilometer

Summary of Calculation Methods for Category 7 (Employee commuting)

Method	*Calculation Formula*	*Activity Data Needed*	*Emission Factor Needed*
Fuel-based method	**sum across fuel types:** ∑ (quantity of fuel consumed (liters) × emission factor for the fuel (e.g., kg CO_2e/liter)) + **sum across grid regions:** ∑ (quantity of electricity consumed (kWh) × emission factor for electricity grid (e.g., kg CO_2e/kWh)) + **sum across refrigerant and air-conditioning types:** ∑ (quantity of refrigerant leakage × global warming potential for the refrigerant (e.g., kg CO_2e)) **If fuel data is unavailable, companies may use the following two formulae to calculate quantities of fuel consumed:** **Calculating fuel use from fuel spend** **sum across fuel types:** $\sum \frac{\text{total fuel spend (e.g., \\$)}}{\text{average fuel price (e.g., \\$/liter)}}$ **Calculating fuel use from distance travelled** sum across transport steps: ∑ (total distance travelled (e.g., km) × fuel efficiency of vehicle (e.g., liters/km))	• Quantities of fuel (e.g., diesel, gasoline, jet fuel, biofuels, etc.) consumed; • Amount spent on fuel and average cost of fuel	• Life cycle fuel emission factors, expressed in units of emissions per unit of energy consumed (e.g., kg CO_2e/liters, CO_2e/Btu, etc.) • For electric vehicles (if applicable), electricity emission factors, expressed in units of emissions per unit of electricity consumed (e.g., kg CO_2e/kWh)
Distance-based method	**first, sum across all employees to determine total distance travelled using each vehicle type:** total distance travelled by vehicle type (vehicle-km or passenger-km) = ∑ (daily one-way distance between home and work (km) × 2 × number of commuting days per year) **then, sum across vehicle types to determine total emissions:** kg CO_2e from employee commuting = ∑ (total distance travelled by vehicle type (vehicle-km or passenger-km) × vehicle specific emission factor (kg CO_2e/vehicle-km or kg CO_2e/passenger-km)) + **(optionally) for each energy source used in teleworking:** ∑ (quantities of energy consumed (kWh) × emission factor for energy source (kg CO_2e/kWh))	• Total distance travelled by employees over the reporting period • Mode of transport used for commuting (e.g., train, subway, bus, car, bicycle, etc.)	Emission factors for each mode of transport (usually expressed in units of greenhouse gas (CO_2, CH_4, N_2O, or CO_2e) emitted per passenger-kilometer travelled)
Average-data method	**sum across each transport mode:** ∑ (total number of employees × % of employees using mode of transport × one way commuting distance (vehicle-km or passenger-km) × 2 × working days per year × emission factor of transport mode (kg CO_2e/vehicle-km or kg CO_2e/passenger-km))	• Number of employees • Average distance travelled by an average employees per day • Average breakdown of transport modes used by employees • Average number working days per year	Emission factors for each mode of transport (usually expressed in units of greenhouse gas (CO_2, CH_4, N_2O, or CO_2e) emitted per passenger-kilometer travelled)

Summary of Calculation Methods for Category 8 (Upstream Leased Assets)

Method	*Calculation Formula*	*Activity Data Needed*	*Emission Factor Needed*
Asset-specific method	**calculate the scope 1 and scope 2 emissions associated with each leased asset:** scope 1 emissions of leased asset = ∑ (quantity of fuel consumed (e.g., liter) × emission factor for fuel source (e.g., kg CO_2e/liter)) + ∑ (quantity of refrigerant leakage (kg) × emission factor for refrigerant (kg CO_2e/kg)) + process emissions scope 2 emissions of leased asset = ∑ (quantity of electricity, steam, heating, cooling consumed (e.g., kWh) × emission factor for electricity, steam, heating, cooling (e.g., kg CO_2e/kWh)) **then sum across leased assets:** ∑ scope 1 and scope 2 emissions of each leased asset **For leased building spaces not sub-metered by the tenant, the following formula can be used to allocate emissions:** energy use from leased space (kWh) $= \frac{\text{reporting company's area (m}^2\text{)}}{\text{building's total qrea (m}^2\text{)} \times \text{building's occupancy rate (e.g.,0.75)}}$ × building's total energy use (kWh)	• Asset-specific fuel use; electricity, steam, heating and cooling use; process emissions; and fugitive emissions (e.g., refrigerant leakage), or; • Asset-specific scope 1 and scope 2 emissions data	• Site or regionally specific emission factors for energy sources (e.g., electricity and fuels) per unit of consumption (e.g., kg CO_2e/kWh for electricity, kg CO_2e/liter for diesel); and • Emission factors of fugitive and process emissions
Lessor-specific method	**calculate the scope 1 and scope 2 emissions associated with each lessor:** scope 1 emissions of lessor = ∑ (quantity of fuel consumed (e.g., liter) × emission factor for fuel source (e.g., kg CO_2e/liter)) + ∑ ((quantity of refrigerant leakage (kg) × emission factor for refrigerant (kg CO_2e/kg)) + process emissions) scope 2 emissions of lessor = ∑ (quantity of electricity, steam, heating, cooling consumed (e.g., kWh) × emission factor for electricity, steam, heating, cooling (e.g., kg CO_2e/kWh)) **then allocate emissions from each lessor and then sum across lessors:** ∑ scope 1 and scope 2 emissions of lessor (kg CO_2e) $\text{x} \; \frac{\text{area, volume, quantity, etc. of the leased asset}}{\text{total area, volume, quantity, etc., of lessor assets}}$	• Lessor's fuel use, electricity use process emissions and fugitive emissions (refrigerant leakage), or; • Lessor's scope 1 and scope 2 emissions data • Physical or financial data for allocation (e.g., total area/volume/quantity of lessor's assets and total area/volume/quantity of leased assets	• Site or regionally specific emission factors for energy sources (e.g., electricity and fuels) per unit of consumption (e.g., kg CO_2e/kWh for electricity, kg CO_2e/liter for diesel); and • Emission factors of fugitive and process emissions
Average-data method	sum across building types: ∑ (total floor space of building type (m^2) × average emission factor for building type (kg CO_2e/m^2/year)) **Reporting company's scope 3 emissions from leased assets other than buildings and for leased buildings where floor space data is unavailable:** **sum across asset types:** ∑ (number of assets x average emissions per asset type (kg CO_2e/asset type/year))	• Floor space of each leased asset • Number of leased assets, by building type; and/or • Number of leased assets that give rise to Scope 2 emissions (e.g., company cars, trucks, etc).	• Average emission factors by floor space, expressed in units of emissions per square meter, square foot occupied (e.g., kg CO_2e/m^2/year); • Average emission factors by building type, expressed in units of emissions per building (e.g., kg CO_2e/small office block/year) • Emission factors by asset type, expressed in units of emissions per asset (e.g., kg CO_2e/car/year)

Summary of Calculation Methods for Category 9 (Downstream transportation and distribution)

Method	*Calculation Formula*	*Activity Data Needed*	*Emission Factors Needed*
Calculating Emissions from Transportation			
Fuel-based method	**sum across fuel types:** ∑ (quantity of fuel consumed (liters) × emission factor for the fuel (e.g., kg CO_2e/liter)) + **sum across grid regions:** ∑ (quantity of electricity consumed (kWh) × emission factor for electricity grid (e.g., kg CO_2e/kWh)) + **sum across refrigerant and air-conditioning types:** ∑ (quantity of refrigerant leakage × global warming potential for the refrigerant (e.g., kg CO_2e)) **If fuel data is unavailable, companies may use the following two formulae to calculate quantities of fuel consumed:** **Calculating fuel use from fuel spend** sum across fuel types: $\sum \frac{\text{total fuel spend (e.g., \$)}}{\text{average fuel price (e.g., \$/liter)}}$ **Calculating fuel use from distance travelled** **sum across transport steps:** ∑ (total distance travelled (e.g., km) × fuel efficiency of vehicle (e.g., liters/km)) Allocated fuel use = $= \text{total fuel consumed (litres)} \times \frac{\text{mass/volume of company's goods}}{\text{mass/volume of goods transported}}$ Companies may optionally substitute mass of goods by volume with dimensional mass or chargeable mass where data is available to prove that the alternative method is more suitable. Dimensional mass is a calculated mass that takes into account packaging volume as well as the actual mass of the goods. Chargeable mass is the higher value of either the actual or the dimensional mass of the goods. (Optional) CO_2e emissions from unladen backhaul = **for each fuel type:** ∑ (quantity of fuel consumed from backhaul × emission factor for the fuel (e.g., kg CO_2e/liter)) where: quantity of fuel consumed from backhaul = average efficiency of vehicles unladed (l/km) × total distance travelled unladen	• Quantities of fuel (e.g., diesel, gasoline, jet fuel, biofuels, etc.) consumed; • Amount spent on fuel and average cost of fuel • Amount of refrigerant leakage; and If applicable: • Distance travelled; • Average fuel efficiency of the vehicle, expressed in units of liters of fuel consumed per tonne per kilometer transported; • Mass of purchased goods in the vehicle (tonnes) • Information on whether the products are refrigerated during transport	• Fuel emission factors, expressed in units of emissions per unit of energy consumed (e.g., kg CO_2e/liters, CO_2e/Btu, etc.) • For electric vehicles (if applicable), electricity emission factors, expressed in units of emissions per unit of electricity consumed (e.g., kg CO_2e/kWh) • Refrigerant leakage emission factors, expressed in units of emissions per unit of refrigerant leaked (e.g., kg CO_2e/kg leakage) Emission factors should include scope 1 and scope 2 emissions of the fuel and optionally include cradle-to-gate emissions.

Summary of Calculation Methods for Category 9 (Downstream transportation and distribution) (continued)

Method	*Calculation Formula*	*Activity Data Needed*	*Emission Factors Needed*
Distance-based method	**sum across transport modes and/or vehicle types:** ∑ (mass of goods purchased (tonnes or volume) × distance travelled in transport leg (km) × emission factor of transport mode or vehicle type (kg CO_2e/tonne or volume/km))	• Mass or volume of the products sold • Actual distances provided by transportation suppliers • Online maps or calculators; and/or • Published port-to-port travel distances	• Emission factor by mode of transport (e.g., rail, air, etc) or vehicle types (e.g., articulated lorry, container vessel, etc), expressed in units of greenhouse gases (CO_2, CH_4, N_2O) per unit of mass (tonne) or volume (e.g., TEU) travelled (e.g., km)
Spend-based method	**sum across transport modes and/or vehicle types:** ∑ (amount spent on transportation by type ($) × relevant EEIO emission factors per unit of economic value (kg CO_2e/$))	• Amount spent on transportation by type (e.g. road, rail, air, barge), using market values (e.g., dollars).	• Cradle-to-gate emission factors of the transportation type per unit of economic value (e.g., kg CO_2e/$) • Where applicable, inflation data to convert market values between the year of the EEIO emissions factors and the year of the activity data.
Calculating Emissions from Distribution			
Site-specific method	**for each storage facility:** emissions of storage facility (kg CO_2e) = (fuel consumed (kWh) × fuel emission factor (kg CO_2e/kWh)) + (electricity consumed (kWh) × electricity emission factor (kg CO_2e)/kWh) + (refrigerant leakage (kg) × refrigerant emission factor (e.g., kg HFC/kg of refrigerant leakage)) **then, allocate emissions based on volume that company's products take within storage facility:** allocated emissions of storage facility = $\frac{\text{volume of reporting company's purchased goods } (m^3)}{\text{total volume of goods in storage facility } (m^3)}$ × emissions of storage facility (kg CO_2e) **finally, sum across all storage facilities:** ∑ allocated emissions of storage facility	• Site-specific fuel, electricity use; and • Site-specific refrigerant leakage • The average occupancy rate of the storage facility (i.e., average total volume of goods stored)	• Site or regionally specific emission factors for energy sources (e.g., electricity and fuels) per unit of consumption (e.g., kg CO_2e/kWh for electricity, kg CO_2e/liter for diesel); and • Refrigerant emission factors of fugitive and process emissions (kg HFC/kg of refrigerant leakage)
Average-data method	**sum across storage facilities:** ∑ (volume of stored goods (m^3 or pallet or TEU) × average number of days stored (days) × emission factor for storage facility (kg CO_2e/m^3 or pallet or TEU/day))	• Companies should collect data based upon the throughput • Volume of purchased goods that are stored (e.g., m^2, m^3, pallet, TEU) or number of pallets needed to store purchased goods • Average number of days that goods are stored	• Companies should collect data which allows the calculation of emissions per unit stored. This can be expressed in several different ways, including; • Emission factor per pallet stored in facility • Emission factor per m^2/m^3 stored in facility • Emission factor per TEU (twenty-foot equivalent unit) stored in facility

Summary of Calculation Methods for Category 10 (Processing of Sold Products)

Method	Calculation Formula	Activity Data Needed	Emission Factor Needed
Site-specific method	**sum across fuel consumed in the processing of sold intermediate products:** ∑ (quantity of fuel consumed (e.g., liter) × life cycle emission factor for fuel source (e.g., kg CO_2e/liter)) + **sum across electricity consumed in the processing of sold intermediate products:** ∑ (quantity of electricity consumed (e.g., kWh) × life cycle emission factor for electricity (e.g., kg CO_2e/kWh)) + **sum across refrigerants used in the processing of sold intermediate products:** ∑ (quantity of refrigerant leakage (kg) × Global Warming Potential for refrigerant (kg CO_2e/kg)) + sum across process emissions released in the processing of sold intermediate products + **to the extent possible, sum across waste generated in the in the processing of sold intermediate products:** ∑ (mass of waste output (kg) × emission factor for waste activity (kg CO_2e/kg))	Companies should first collect data on the types and quantities of intermediate goods sold by the reporting company. Companies should then collect either site-specific GHG emissions data provided by downstream value chain partners, or site-specific activity data from downstream processes, including: • Quantities of energy (including electricity and fuels) consumed in process(es) • To the extent possible, mass of waste generated in process(es); and • If applicable, activity data related to non-combustion emissions (i.e., industrial process or fugitive emissions)	• If site-specific activity data is collected, companies should also collect: • Emission factors for fuels • Emission factors for electricity • To the extent possible, emission factors for waste outputs; and • If applicable, emission factors related to non-combustion emissions (i.e., industrial process or fugitive emissions)
Average-data method	**sum across intermediate products:** ∑ (mass of sold intermediate product (kg) × emission factor of processing of sold products (kg CO_2e/kg of final product))	For each type of sold intermediate product, companies should collect data on: • The process(es) involved in transforming or processing sold intermediate products into an usable state final product, subsequent to sale by the reporting company; • Information needed for allocation (e.g., mass, economic value, etc.)	• Companies should collect either: • Average emission factors for downstream processes to transform the sold intermediate product, expressed in units of emissions (e.g., CO_2, CH_4, N_2O) per unit of product (e.g., kg CO_2/kg of final product) Or: • Life cycle emission factors of sold products • Life cycle emission factors of final products

Summary of Calculation Methods for Category 11 (Use of sold products)

Method	*Calculation Formula*	*Activity Data Needed*	*Emission Factor Needed*
Direct Use-Phase Emissions			
Products that directly consume energy (fuels or electricity) during use	**sum across fuels consumed from use of products:** ∑ (total lifetime expected uses of product × number sold in reporting period × fuel consumed per use (kWh) × emission factor for fuel (kg CO_2e/kWh)) + **sum across electricity consumed from use of products:** ∑ (total lifetime expected uses of product × number sold in reporting period × electricity consumed per use (kWh) × emission factor for electricity (kg CO_2e/kWh)) + **sum across refrigerant leakage from use of products:** ∑ (total lifetime expected uses of product × number sold in reporting period × refrigerant leakage per use (kg) × global warming potential (kg CO_2e/kg))	• Total lifetime expected uses of product(s); and • Quantities of products sold • Fuel used per use of product • Electricity consumption per use of product • Refrigerant leakage per use of product	• Emission factors for fuels • Emission factors for electricity • Emission factors for refrigerants
Fuels and Feed-stocks	**sum across fuels/feedstocks:** ∑ (total quantity of fuel/feedstock sold (e.g., kWh) × combustion emission factor for fuel/feedstock (e.g., kg CO_2e/kWh))	• Total quantities of fuels/feed-stocks sold	• Combustion emission factors of fuel/feedstock
Greenhouse gases and products that contain or form green-house gases that are emitted during use	**sum across GHGs released in a product or product group:** ∑ (GHG contained per product × Total Number of products sold × % of GHG released during lifetime use of product × GWP of the GHG) **then:** **sum across products or product groups:** ∑ (use phase emissions from product or product group 1,2,3…) Note: if the % released is unknown 100% should be assumed.	• Total quantities of products sold • Quantities of GHGs contained per product • % of GHGs released through-out the lifetime of the product	• GWP of the GHGs contained in the product, expressed in units of carbon dioxide per unit kilogram of the GHG (e.g., 25 kg CO_2/kg)

Summary of Calculation Methods for Category 11 (Use of sold products) (continued)

Method	*Calculation Formula*	*Activity Data Needed*	*Emission Factor Needed*
Indirect Use-Phase Emissions			
Products that indirectly consume energy (fuels or electricity) during use	The generation of a typical use phase may be difficult as the same product may consume more or less energy dependent on the conditions in which it is used. For example, a potato may be roasted, boiled and microwaved, each using different amount of energy and hence different emissions. Companies may choose to identify several different use-phase scenarios for a product and create a weighted average based upon actual activity. **sum across fuels consumed from use scenarios:** ∑ (total lifetime expected uses of product × % of total lifetime uses using this scenario × number sold in reporting period × fuel consumed per use in this scenario (e.g., kWh) × emission factor for fuel (e.g., kg CO_2e/kWh)) + **sum across electricity consumed from use scenarios:** ∑ (total lifetime expected uses of product × % of total lifetime uses using this scenario × number sold in reporting period × electricity consumed per use in this scenario (kWh) × emission factor for electricity (kg CO_2e/kWh)) + **sum across refrigerant leakage from use scenarios:** ∑ (total lifetime expected uses of product × % of total lifetime uses using this scenario × number sold in reporting period × refrigerant leakage per use in this scenario (kg) × emission factor for refrigerant (kg CO_2e/kg)) + **sum across GHG emitted indirectly from use scenarios:** ∑ (total lifetime expected uses of product × % of total lifetime uses using this scenario × number sold in reporting period × GHG emitted indirectly (kg) × GWP of the GHG)	• Average number of uses over lifetime of product • Average use scenarios (e.g., weighted average of scenarios) • Fuel consumed in use scenarios • Electricity consumed in use scenarios • Refrigerant leakage in use scenarios • GHGs emitted indirectly in use scenarios	• Combustion emission factors of fuels and electricity • GWP of GHGs
Intermediate products that directly consume energy (fuels or electricity) during use	**sum across sold intermediate products total use phase emissions:** ∑ (total intermediate products sold × total lifetime uses of final sold product × emissions per use of sold intermediate product (kg CO_2e/use))	• Type(s) of final product(s) produced from reporting company's intermediate product(s) • Percentage of reporting company's intermediate product sales going to each type of final product • Activity data required to calculate the use-phase emission of the final product will be the same as described previously in this chapter.	• Depending on the type of final product, emission factors required will be the same as described earlier in this chapter.

Summary of Calculation Methods for Category 12 (End-of-life treatment of sold products)

Method	*Calculation Formula*	*Activity Data Needed*	*Emission Factor Needed*
Waste-type-specific method	**sum across waste treatment methods for sold products and packaging:** ∑ (total mass of sold products and packaging from point of sale to end of life after consumer use (kg) × % of total waste being1 treated by waste treatment method × emission factor of waste treatment method (kg CO_2e/kg))	• Total mass of sold products and packaging from the point of sale by the reporting company to the end-of-life after consumer use (including packaging used to transport products through to the point of retail and any packaging that is disposed of prior to the end-of-life of the final product. • Proportion of this waste being treated by different methods (e.g., % landfilled, incinerated, recycled, etc.)	• Average waste treatment specific emission factors based upon all waste disposal types

Summary of Calculation Methods for Category 13 (Downstream Leased Assets)

Method	*Calculation Formula*	*Activity Data Needed*	*Emission Factor Needed*
Asset-specific method	**calculate the scope 1 and scope 2 emissions associated with each leased asset:** scope 1 emissions of leased asset = ∑ (quantity of fuel consumed (e.g., liter) × emission factor for fuel source (e.g., kg CO_2e/liter)) + ∑ ((quantity of refrigerant leakage (kg) × emission factor for refrigerant (kg CO_2e/kg)) + process emissions) scope 2 emissions of leased asset = ∑ (quantity of electricity, steam, heating, cooling consumed (e.g., kWh) × emission factor for electricity, steam, heating, cooling (e.g., kg CO_2e/kWh)) **then sum across leased assets:** ∑ scope 1 and scope 2 emissions of each leased asset **For leased building spaces not sub-metered by the tenant, the following formula can be used to allocate emissions:** energy use from leased space (kWh) $= \frac{\text{reporting company's area } (m^2)}{\text{building's total area } (m^2)}$ × building's occupancy rate (e.g., 0.75)) × building's total energy use (kWh)	• Asset-specific fuel use; electricity, steam, heating and cooling use; process emissions; and fugitive emissions (e.g., refrigerant leakage), or; • Asset-specific scope 1 and scope 2 emissions data	• Site or regionally specific emission factors for energy sources (e.g., electricity and fuels) per unit of consumption (e.g., kg CO_2e/kWh for electricity, kg CO_2e/liter for diesel); and • Emission factors of fugitive and process emissions

Summary of Calculation Methods for Category 13 (Downstream Leased Assets) (continued)

Method	Calculation Formula	Activity Data Needed	Emission Factor Needed
Lessee-specific method	**calculate the scope 1 and scope 2 emissions associated with each lessee:** scope 1 emissions of lessee = ∑ (quantity of fuel consumed (e.g., liter) × emission factor for fuel source (e.g., kg CO_2e/liter)) + ∑ ((quantity of refrigerant leakage (kg) × emission factor for refrigerant (kg CO_2e/kg)) + process emissions) scope 2 emissions of lessee = ∑ (quantity of electricity, steam, heating, cooling consumed (e.g., kWh) × emission factor for electricity, steam, heating, cooling (e.g., kg CO_2e/kWh)) **then allocate emissions from each lessee and then sum across lessees:** ∑scope 1 and scope 2 emissions of lessee (kg CO_2e) × ((area, volume, quantity, etc., of the leased asset) / (total area, volume, quantity, etc. of lessee assets))	• Lessee's fuel use, electricity use process emissions and fugitive emissions (refrigerant leakage), or; • Lessee's scope 1 and scope 2 emissions data • Physical or financial data for allocation (e.g., total area/volume/quantity of lessee's assets and total area/volume/quantity of leased assets	• Site or regionally specific emission factors for energy sources (e.g., electricity and fuels) per unit of consumption (e.g., kg CO_2e/kWh for electricity, kg CO_2e/liter for diesel); and • Emission factors of fugitive and process emissions
Average-data method	**Reporting company' s scope 3 emissions from leased assets (downstream):** **sum across building types:** ∑ (total floor space of building type (m^2) × average emission factor for building type (kg CO_2e/m^2/year)) **reporting company's scope 3 emissions from leased assets other than buildings and for leased buildings where floor space data is unavailable:** **sum across asset types:** ∑ (number of assets x average emissions per asset type (kg CO_2e/asset type/year))	• Floor space of each leased asset • Number of leased assets, by building type; and/or • Number of leased assets that give rise to Scope 2 emissions (e.g., company cars, trucks, etc).	• Average emission factors by floor space, expressed in units of emissions per square meter, square foot occupied (e.g., kg CO_2e/m^2/year); • Average emission factors by building type, expressed in units of emissions per building (e.g., kg CO_2e/small office block/year) • Emission factors by asset type, expressed in units of emissions per asset (e.g., kg CO_2e/car/year)

Summary of Calculation Methods for Category 14 (Franchises)

Method	*Calculation Formula*	*Activity Data Needed*	*Emission Factor Needed*
Franchise–specific method	**sum across franchises:** ∑ (scope 1 emissions + scope 2 emissions of each franchise (kg CO_2e)) **If franchise buildings are not submetered, the following equation can be used:** energy use from franchise (kWh) = (franchise's area (m^2)) / (building's total area (m^2) × building's occupancy rate) × building's total energy use (kWh)	Companies should collect data on either: • Scope 1 and scope 2 emissions data from franchisees; or • Site-specific fuel use, electricity use, and other process and fugitive emissions activity data	If collecting fuel and energy data, companies should also collect: • Site- or regionally-specific emission factors for energy sources (e.g., electricity and fuels) per unit of consumption (e.g., kg CO_2e/kWh for electricity, kg CO_2e/liter for diesel); and • Emission factors of process emissions (e.g., refrigeration and air conditioning)
Average-data method	**For leased buildings (if floor space data is available), sum across building types:** **sum across building types:** ∑ (total floor space of building type (m^2) × average emission factor for building type (kg CO_2e/m^2/year)) **For other asset types or for leased buildings where floor space data is not available, sum across building/asset types:** **sum across building/asset types:** ∑ (number of buildings or assets × average emissions per building or asset type per year (kg CO_2e/building or asset type/year))	• Floor space of each franchise, by floor space • Number of franchises, by building type • Number of franchise assets that give rise to Scope 2 emissions (e.g., company cars, trucks, etc).	• Average emission factors by floor space, expressed in units of emissions per square meter, square foot occupied (e.g., kg CO_2e/m^2) • Average emission factors by building type, expressed in units of emissions per building (e.g., kg CO_2e/small office block) • Emission factors by asset type, expressed in units of emissions per asset (e.g., kg CO_2e/car)

Summary of Calculation Methods for Category 15 (Investments)

Method	*Calculation Formula*	*Activity Data Needed*	*Emission Factor Needed*
Calculating emissions from equity investments			
Investment-specific method	**sum across equity investments:** ∑ (scope 1 and scope 2 emissions of equity investment × share of equity (%))	• Scope 1 and 2 emissions of investee company • The investor's proportional share of equity in the investee • If significant, companies should also collect scope 3 emissions of investee company (if investee companies are unable to provide scope 3 emissions data, scope 3 emissions may need to be estimated using the Average-data method)	• If using the investment-specific method, the reporting company collects emissions data from investees, so no emission factors are required
Average-data method	**sum across equity investments:** ∑ ((investee company total revenue ($) × emission factor for investee's sector (kg CO_2e/$ revenue)) × share of equity (%))	• Sector(s) the investee company operates in; • Revenue of investee company (if the investee company operates in more than one sector, the reporting company should collect data on the revenue for each sector in which the investee company operates); and • The investor's proportional share of equity in the investee	• EEIO emission factors for the sectors of the economy that the investments are related to (kg CO_2e/$ revenue)
Calculating emissions from project finance and from debt investments with known use of proceeds			
Project-specific method	**sum across projects:** ∑ (scope 1 and scope 2 emissions of relevant project in the reporting year × share of total project costs (%))	• Scope 1 and 2 emissions that occur in the reporting year for the relevant projects • The investor's proportional share of total project costs (total equity plus debt)	• If using the project-specific method, the reporting company collects emissions data from investees, so no emission factors are required
Average-data method	**sum across projects in the construction phase:** ∑ ((project construction cost in the reporting year ($) x emission factor of relevant construction sector (kg CO_2e/$ revenue)) x share of total project costs (%)) **sum across projects in the operational phase:** ∑ ((project revenue in the reporting year ($) x emission factor of relevant operating sector (kg CO_2e/$ revenue)) x share of total project costs (%))	• Project costs in the reporting year (if the project is in the construction phase); or • Revenue of the project (if the project is in the operational phase); and • The investor's proportional share of total project costs (total equity plus debt).	• EEIO emission factors for the relevant construction sector that the investments are related to (kg CO_2e/$) (if the project is in the construction phase); or • EEIO emission factors for the relevant operating sector that the investments are related to (kg CO_2e/$) (if the project is in the operational phase)
Calculating total projected lifetime emissions from project finance and debt investments with known use of proceeds			
Project-specific method	∑ ((projected annual emissions of project x projected lifetime of project) x share of total project costs (%))	Calculating projected lifetime emissions typically requires making assumptions about the operation of the asset and its expected lifetime. The data needed to calculate expected emissions will depend on the type of project. Companies should collect: • Expected average annual emissions of project. For power plants for example, emissions can be derived from the plant's capacity and heat rate, the carbon content of the fuel, and projected capacity utilization. • Expected lifetime of project	