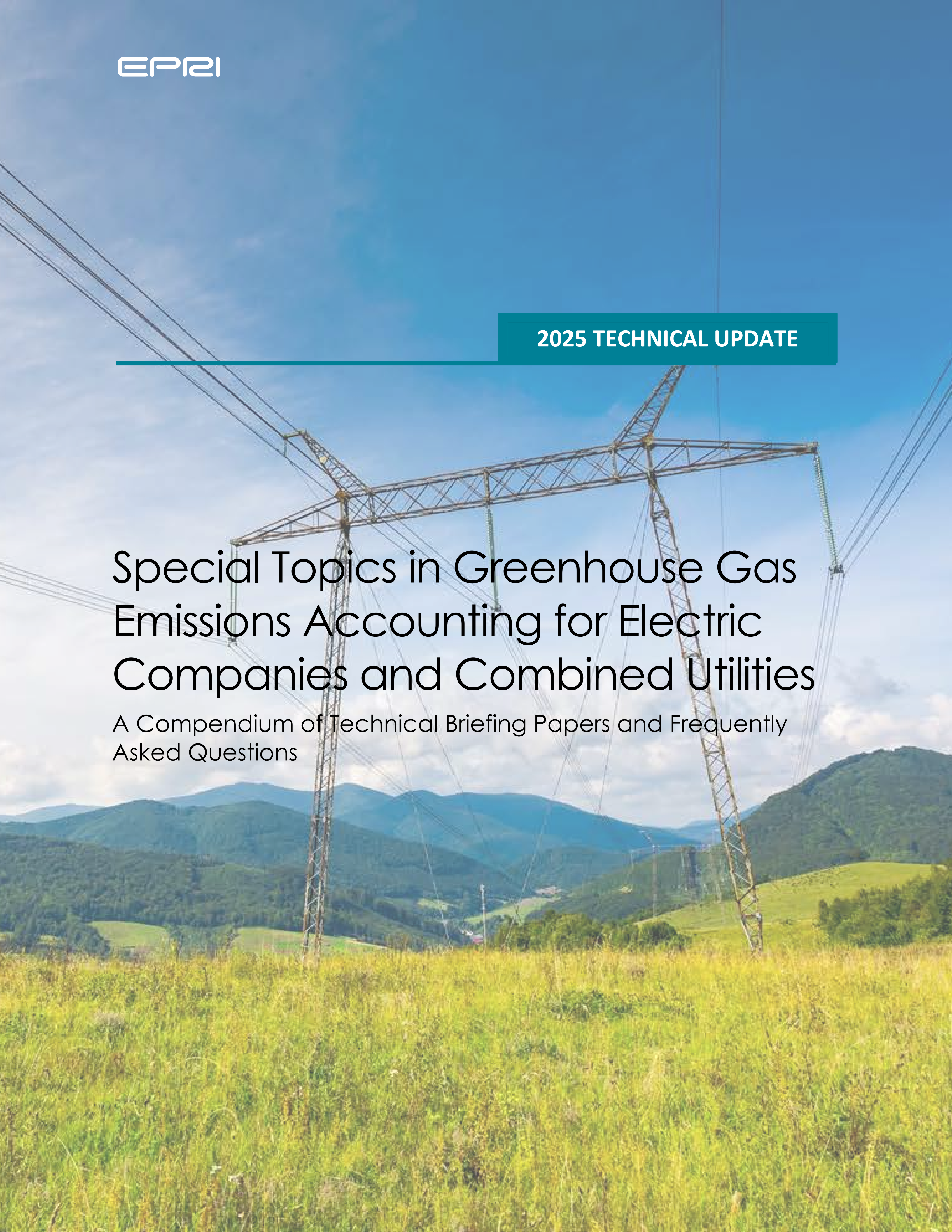

EPRI

2025 TECHNICAL UPDATE

Special Topics in Greenhouse Gas Emissions Accounting for Electric Companies and Combined Utilities

A Compendium of Technical Briefing Papers and Frequently Asked Questions

Special Topics in Greenhouse Gas Emissions Accounting for Electric Companies and Combined Utilities

A Compendium of Technical Briefing Papers and Frequently Asked Questions

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Technical Brief, March 2025

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ABSTRACT

As a consequence of significant and growing stakeholder and regulatory interest in "climate disclosure" and transparent accounting of corporate scope 1, 2, and 3 emissions, there is a growing need for electric companies and combined electric and natural gas utilities to conduct technically grounded greenhouse gas (GHG) emissions accounting and reporting.

To address this need, EPRI's program on Energy, Environmental, and Climate Policy Analysis (P201) in 2021 completed a supplemental project focused on transferring in-depth technical knowledge and expertise related to scope 1 and 2 emission accounting and reporting. In 2023, EPRI launched a follow-up project focused on "*Scope 3 Greenhouse Gas Emissions Accounting for Electric Companies and Combined Utilities*" to provide technical insight into accounting and reporting for the 15 scope 3 emissions accounting categories. During the course of completing these two projects, EPRI identified a variety of key issues and special topics associated with GHG accounting for electric companies and combined utilities that require deeper understanding and investigation.

To address these topics more directly, EPRI launched a follow-up supplemental project in 2024 on *Special Topics in Greenhouse Gas Emissions Accounting for Electric Companies and Combined Utilities.* This report is a compendium of briefing papers and Frequently Asked Questions (FAQ) developed to support a series of webcasts EPRI hosted in 2024 and 2025 as part of this supplemental project. This technical transfer project focused specifically on improving participants' understanding of (i) accounting and reporting for electricity and natural gas transmission and distribution related emissions in scope 1, 2, and/or 3; (ii) location- and market-based approaches to GHG accounting for scope 2 indirect emissions; (iii) GHG inventory base year recalculation methods and approaches; and (iv) scope 3 insetting.

Keywords

Carbon emissions
GHG emissions accounting
Greenhouse gas
Indirect emissions
Insetting
Market-based accounting

EXECUTIVE SUMMARY

Deliverable Number: 3002031993

Product Type: Technical Update

Product Title: Special Topics in Greenhouse Gas Emissions Accounting for Electric Companies and Combined Utilities: A Compendium of Technical Briefing Papers and Frequently Asked Questions

Primary Audience: Staff from electric companies and combined utilities engaged in developing corporate greenhouse gas (GHG) emissions inventories or corporate GHG emissions goal setting; as well as staff responsible for environmental reporting, GHG emissions accounting, sustainability reporting, resource planning, corporate strategy, and communications.

Secondary Audience: Staff and managers of electric companies and combined electric and natural gas utilities who are responsible for corporate strategy, including sustainability, corporate reporting, and decarbonization goals. Other audiences include staff of organizations engaged in corporate environmental disclosure and policymakers focused on decarbonization and climate mitigation.

KEY RESEARCH QUESTION

Corporate GHG emissions accounting is a complex and inexact undertaking. Electric companies and combined electric and natural gas utilities typically rely on guidance provided in protocols developed by non-profit organizations, such as the World Resources Institute (WRI) and The Climate Registry (TCR), to account and report their corporate GHG emissions.

This report is a compendium of briefing papers and Frequently Asked Questions (FAQ) developed to support a series of webcasts EPRI hosted in 2024 and 2025 as part of an EPRI supplemental project on *Special Topics in Greenhouse Gas Emissions Accounting for Electric Companies and Combined Utilities*. This technical information transfer project was designed to improve participants' understanding of (i) accounting and reporting for electricity and natural gas transmission and distribution related emissions in scope 1, 2, and/or 3; (ii) location- and market-based approaches to GHG accounting for scope 2 indirect emissions; (iii) GHG inventory base year recalculation methods and approaches; and (iv) scope 3 insetting.

RESEARCH OVERVIEW

In recent years, policymakers, regulators, and stakeholders have increased their focus on technical considerations associated with GHG emissions accounting and reporting.

In 2024-25, EPRI hosted a series of technical webcasts to explore key technical challenges associated with GHG emissions accounting and reporting for electric companies and combined utilities. In partnership with the non-profit Greenhouse Gas Management Institute (GHGMI), EPRI prepared a series of technical briefing papers to support these presentations. These briefing papers provided project participants with background information on topics to be discussed during each webcast. Throughout this project, EPRI noted questions asked by project participants and compiled them into a Frequently Asked Questions (FAQ) document.

This compendium is comprised of the technical briefing papers prepared by EPRI to support these project webcasts and the FAQ. The original briefing papers and the FAQ have been reformatted and edited slightly to integrate them into this EPRI report.

KEY FINDINGS

GHG Accounting for Transmission and Distribution Line Losses

- Scope 2 emissions include the indirect GHG emissions from purchased or acquired electricity, steam, heating, and cooling generated by another entity and consumed by the reporting company.
- Scope 2 also includes emissions associated with "line losses" that occur as electricity is moved across an electric company's transmission and distribution (T&D) systems. The classification of T&D line losses within GHG accounting scopes depends in part on an electric company's corporate structure.
- The term "common carrier" refers to a company that (i) owns the transportation or transmission infrastructure, such as natural gas pipelines and electricity T&D systems, and (ii) the company does not own the natural gas or electricity passing through these systems. Common carriers provide a transportation or transmission service to electricity generators and/or natural gas producers.
- Accounting for and reporting emissions associated with products that are distributed but not sold, such as natural gas and electricity transported via common carrier infrastructure, presents GHG accounting challenges for owners of this type of infrastructure because the available guidance for addressing these situations is ambiguous and not definitive.
- The GHG Protocol also does not provide specific guidance for treating indirect emission sources occurring in the value chain of natural gas pipeline owners when they do not own or control the natural gas flowing through their systems.
- Electric companies and combined utilities have several options to account for and report GHG emissions associated with the transportation of products distributed but not sold via common carrier infrastructure, including: (i) Expand the GHG reporting boundary and report ambiguous emission sources within scope 3, categories 3 and 11; (ii) Report GHG emissions outside of the 15 categories, but within scope 3; and, (iii) Exclude accounting and reporting of emissions associated with these ambiguous emissions boundaries due to a lack of guidance from the Scope 3 Standard.

Location and Market-based GHG Emissions Accounting

- Scope 2 emissions from purchased electricity often make up a large source of GHG emissions for commercial and industrial (C&I) electricity customers, but it can be challenging to reduce these emissions because they are not under their direct control.
- The GHG Protocol's Scope 2 Guidance provides direction on how entities should account for, and report scope 2 emissions associated with acquired electricity, steam, heating, and cooling. The GHGP provides reporters with two methods to report these scope 2 emissions — the "location-based" and "market-based" methods
- The location-based approach uses either direct line or grid average EFs to estimate and report scope 2 emissions associated with purchased electricity. The location-based method reflects the average GHG emissions intensity of power generation on a power grid where energy consumption occurs in the absence of a direct line EF that would represent electricity emissions intensity from a specific power plant to the end-user.
- Market-based approaches attempt to allocate GHG emissions from specific power plants to specific end-users based on the GHG emissions associated with electricity that end-use customers have procured using power purchase agreements (PPAs) and other types of financial and contractual instruments.
- Existing GHG accounting protocols allow companies to procure renewable energy (RE) and renewable energy credits (RECs) and then use market-based accounting to claim a reduction in their reported scope 2 emissions associated with the RE and RECs they purchase.
- Using the market-based approach, a reporting company can replace a location-based EF with a market-based EF that reflects the emissions associated with the electricity it procured via PPAs and other mechanisms. The market-based method allows companies to apply lower GHG-intensive EFs (e.g., 0 tonne CO_2e/MWh) and report zero scope 2 emissions, even if the company does not actually consume the contracted RE.
- The primary difference between location- and market-based approaches is the EF used to represent the emissions intensity (tCO_2/MWh) of purchased electricity. Several distinct types of EFs have been developed to represent electricity consumed from a power grid to estimate indirect scope 2 GHG emissions, including direct connection EFs, grid-average EFs, residual mix EFs, contractual EFs, and supplier-specific EFs.
- There is now widespread recognition that using market-based accounting to claim reduced corporate scope 2 emissions may lead to inaccurate allocation of GHG emissions. In 2022, the GHG Protocol began a comprehensive multi-year long effort to review and potentially revise the existing GHG Protocol's Corporate Standard, Scope 2 Guidance, Scope 3 Standard, and Market-based Accounting Approaches.

Base Year and Historical Recalculation

- A base year inventory, in the context of corporate GHG emissions inventory accounting, is a reference point in the past to which current emissions can be compared.
- Recalculating base year and historic GHG emission inventories refers to the process of re-estimating a reporting company's historic emissions due to structural changes in its organizational or operational boundaries or other "significant" changes.
- The GHG Protocol's Corporate Accounting and Reporting Standard requires reporting companies to develop an internal emissions recalculation policy that includes: (i) the company's procedure for performing a recalculation, (ii) an explanation of the types of events that would trigger a recalculation, and (iii) the significance threshold the company will use to evaluate changes that may trigger recalculation.
- A significance threshold is a quantitative or qualitative criterion that defines what changes are "significant" enough to trigger a recalculation of base year and historic emissions by a reporting company. The threshold is established relative to the base year inventory. There is no standard guidance for what threshold a company should set. However, a reporting program may require a specific significance threshold. A range of 2-5% is a common significance threshold.
- A recalculation always will be triggered if structural changes to the reporting boundaries meet the reporting company's significance threshold, or if other changes meet the significance threshold, such as changes in calculation methodology, changes in EFs used, and/or the discovery of errors.
- A structural change refers to a change that involves the transfer of ownership or control of an emissions-producing facility, activity, or operation from one company to another. Structural changes include mergers, acquisitions, divestments, and specific situations related to outsourcing or insourcing of activities or operations.
- Three types of changes that do <u>not</u> trigger base year recalculation: (i) organic growth or decline, (ii) some situations related to outsourcing and insourcing, and (iii) acquiring (or insourcing) and divesting (or outsourcing) facilities that did not exist in the base year.
- Whether outsourcing or insourcing triggers a recalculation depends on if the reporting company (i) set single or separate base years or GHG targets for individual scopes or for total GHG emissions, and (ii) previously reported the activity being outsourced or insourced. If the reporting company has a single base year or GHG target for total emissions (as opposed to a base year and/or GHG target for individual scopes), *and* the reporting company previously reported emissions from the outsourced or insourced activity, then a recalculation is *not* triggered. If the reporting company has separate base years and/or GHG targets for individual scopes, *or* if the reporting company did not previously report the outsourced or insourced activity, then a recalculation *is* triggered.
- If a reporting company changes the calculation method(s) used to estimate the GHG emissions associated with a previously reported activity (e.g., shifting from the spend-based approach to the fuel-based approach for a scope 3 category), a recalculation is required if the change meets the reporting company's significance threshold.

- There are two standard approaches to performing a recalculation: the “all-year” and “pro-rata” approaches. The pro-rata approach is rarely used in practice as it is more complicated and requires the reporting company to recalculate historic emissions twice for the same change. The all-year approach is therefore recommended in most circumstances.
- The recalculation of a base year and/or historic emission inventories may have important implications for reporting companies, such as (i) documentation of recalculated emission estimates in future inventory reports and other related communications, (ii) potential revision of GHG targets if the recalculation substantially increases base year inventory emissions, and (iii) impacts to corporate reputation. Recalculation demonstrates a company’s decision to maintain time series consistency and accurate tracking of physical inventory time series emission reductions.

Scope 3 Insetting

- Insetting is an emerging controversial approach that has been proposed to allow companies to report lower scope 3 value chain emissions by supporting the implementation of project “interventions” within (or in proximity to) a company’s value chain. Insetting has not been widely accepted by GHG accounting experts and is still evolving conceptually and methodologically.
- Insetting does not necessarily physically lower an entity’s scope 3 emissions, but rather allows companies to report lower scope 3 emissions. Also, insetting does not necessarily require a reporting company to be the entity directly implementing an insetting intervention; they may rely on a third party or community partner or provide financial support to those entities implementing the intervention.
- Given the lack of substantive guidance about appropriate methods to implement insetting, there could be significant risks to companies that seek to execute insetting activities in the near term. Companies implementing insetting activities can expect to be challenged by interested stakeholders and media institutions about the credibility of insetting claims and the determination of the GHG emissions impact associated with any insetting interventions.
- For companies that wish to use insetting, the “Gold Standard Value Chain (Scope 3) Interventions Greenhouse Gas Accounting & Reporting Guidance provides guidance related to (i) Accounting for the net emission changes associated with a given value chain intervention; (ii) Credible accounting in the company’s scope 3 inventory and reporting, where appropriate; and, (iii) Making narrative claims that describe the company’s role in the Intervention and the impacts arising from it.
- Insetting is similar to offsetting (i.e., using carbon credits to offset emissions), but currently lacks similar high-level programmatic and technical requirements that must be fulfilled when implementing a carbon crediting project consistent with a program-approved methodology and following the auditing and other crediting program requirements to produce carbon credits.

- Insetting has been conceptualized in part based on project-level consequential GHG accounting that has been used for many years to quantify the carbon credits generated by offset projects.
- There are three basic steps involved in conceptualizing and quantifying avoided GHG emissions and/or enhanced removals associated with insetting interventions: (i) select and define the intervention; (ii) define the intervention's baseline scenario and quantify its avoided GHG emissions impact; and, (iii) monitor, report, and verify (MRV) the intervention's avoided emissions and/or enhanced removals.
- Guidance for how to transition the quantification methods used in project-level carbon crediting methodologies so they can be used for insetting is still under development. Carbon crediting programs like Gold Standard (GS) and Verra currently are working to transition existing approved carbon crediting methodologies to be used for insetting.
- Insetting interventions can help companies report lower scope 3 emissions if calculation methodologies and data used to estimate the emissions inventory are sensitive enough to detect changes resulting from the intervention. This still requires the quantification of the intervention's impact to remain distinct from the scope 3 inventory estimation.

WHY THIS MATTERS

A growing number of electric companies and combined utilities have adopted aggressive goals to reduce their company's GHG emissions by 2030 and beyond. Some have gone a step further and aligned with the Paris Agreement global targets to mitigate the worst effects of climate change adopting "net zero" or carbon neutral GHG emissions goals by 2050 or earlier.

As electric companies and combined electric and natural gas utilities develop strategies and plans to reduce their future GHG emissions, there is a need for sector specific guidance on unique emissions accounting challenges faced by electric companies and combined utilities.

HOW TO APPLY RESULTS

This compendium and frequently asked questions (FAQ) can serve as technical reference material for (i) accounting and reporting for electricity and natural gas transmission and distribution related emissions in scope 1, 2, and/or 3; (ii) location- and market-based approaches to GHG accounting for scope 2 indirect emissions; (iii) GHG inventory base year recalculation methods and approaches; and (iv) scope 3 insetting. Interested readers can use the information presented in this report to understand unique challenges related to GHG emissions accounting for electric companies and combined utilities.

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PROGRAMS: Energy, Environmental, and Climate Policy Analysis, P201; andGreenhouse Gas Emissions Accounting and Strategic Applications, P261

KEY TERMS

Key Term	Description
Activity data	Data related to an activity resulting in GHG emissions. Primary *AD* is data specific to a supplier's activities. Secondary AD represents generic emissions data, such as industry or regional-average data, financial data, or proxy data.
Allocational GHG accounting	A physical GHG accounting framework that measures emissions physically released into the atmosphere within a defined boundary and allocates (i.e., assigns responsibility for) those emissions to an entity (e.g., company, organization, nation). Allocational GHG accounting cannot be used to measure the emission consequences that occur outside of the defined boundary.
All year approach	A GHG inventory recalculation approach that applies the full change of emissions for an entire year, regardless of whether the change occurred partway through the year or not.
Average GHG emission factor	A coefficient that quantifies the emissions or removals of a gas per unit activity. Emission factors (EFs) are often based on a sample of measurement data, averaged to develop a representative rate of emission for a given activity level under a given set of operating conditions.
Base year	A base year in a GHG emissions inventory is a reference point in the past to which current emissions can be compared.
Common carrier	Refers to a company that owns the transportation or transmission infrastructure, such as natural gas pipelines and electricity T&D systems. However, these companies do not necessarily own the natural gas or electricity passing through these systems.
Consequential GHG accounting	A physical GHG accounting framework that measures the emissions impact of interventions/decisions and does not assign responsibility to a specific entity. Involves estimating the time series of differences in physical quantities (mass) of atmospheric GHG emissions and removals between a baseline (i.e., non-intervention) scenario and an intervention scenario, to estimate the change in emissions and removals caused by an intervention. Consequential GHG accounting may also be referred to as "intervention," "crediting project," or "offset project" accounting.

Key Term	Description
Contractual instruments	Any type of contract between two parties for the sale and purchase of energy bundled with attributes relating to the energy generation, or for unbundled attribute claims.
Direct emissions	Direct emissions result from a company's owned or controlled equipment, facilities, or operational activities that physically release (or remove) GHGs into the atmosphere. Direct emissions are also referred to as "scope 1" emissions.
Emissions factor (EF)	A representative value that relates the quantity of a pollutant released to the atmosphere with an activity associated with the release of that pollutant. Typically, EFs are expressed as the mass of a GHG pollutant per unit of the emission-producing activity (e.g., lbs. CO_2 / MWh).
Fixed base year	A GHG inventory base year that is static and does not change at predetermined intervals. Many GHG programs require a fixed base year policy.
Indirect emissions	Indirect emissions can be either scope 2 or scope 3, and result from sources that are not owned or operated by the company but are essential to the company's operations.
Intervention	An umbrella term for any action that introduces a change to a scope 3 activity. This could include a new technology, practice, or supply change (e.g., a shift to a different product input or sourcing location) to avoid emissions or enhance removals. An Intervention may include changes to several activities that avoid emissions or enhance removals in different ways and that may or may not be included within the Scope 3 Inventory.
Leakage	An unintentional increase in emissions or decrease in removals caused by an intervention, relative to the intervention's baseline scenario, which typically occurs at sources or sinks physically separate from the location where the intervention is implemented. For example, leakage can occur due to a shift in where emissions occur (activity shifting leakage), due to market responses (market leakage), changes in human activity near a project, or changes in physical processes.

Key Term	Description
Marginal GHG emissions factor	The GHG emissions that occur from the production of one additional unit of an activity. In theory, a marginal EF can be used to quantify the emissions that would result from increasing an activity or the emissions that would be avoided from decreasing an activity.
Operational boundary	An operational boundary identifies which company operations and sources generate emissions within its organizational boundary and categorizes the emission sources into the appropriate emissions scopes.
Organizational GHG emissions inventory	An organizational (also called corporate or entity-level) GHG emissions inventory is an assessment of the GHG emissions and removals allocated to an entity's operations over a defined period, typically a calendar or fiscal year.
Organic growth /decline	Increases or decreases in the reporting company's production output, changes in product mix, and closures or openings of facilities.
Organizational boundary	Organizational boundaries define how a company consolidates its GHG emissions inventory by determining which activities and operations are owned and/or controlled by the company.
Physical GHG accounting	The quantification of GHG fluxes within the atmosphere, including changes in those fluxes. This includes both the physical reality and the potential physical reality of emission fluxes in the atmosphere. The two forms of physical GHG accounting include the allocational and consequential GHG accounting frameworks.
Pro-rata approach	A GHG inventory recalculation approach that pro-rates emissions data to reflect changes that occurred partway through the year.
Rolling base year	A reporting company's GHG inventory base year rolls forward at regular intervals, typically one year. Note: this type of base year may be useful for companies that grow rapidly due to acquisitions.
Scope 1 emissions	Direct GHG emissions that result from a company's owned or controlled equipment, facilities, or operational activities that emit (or remove) GHGs.

Key Term	Description
Scope 2 emissions	Scope 2 accounts for indirect GHG emissions from purchased or acquired electricity, steam, heating, and cooling that are generated by another entity and consumed by the reporting company. Also, generally includes emissions associated with electric company T&D system “line losses.”
Scope 3 emissions	Scope 3 emissions are all other indirect GHG emissions not included in scope 2. There are 15 categories of “upstream” and “downstream” scope 3 accounting categories.
Significance threshold	A threshold defined within the reporting company’s GHG inventory recalculation policy that states qualitative and/or quantitative criteria that trigger a GHG inventory base year recalculation.
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.
Structural change	A change in corporate or organizational structure(s) that results in a shift of ownership of emissions, such as mergers, acquisitions, and divestments.
Time series consistency	The reporting company’s GHG inventory base year and historic to current inventories have consistent data sets, use consistent EFs and other input parameters, and apply methodologies consistently. Time series consistency allows for meaningful emission comparisons within a company’s emissions profile.
Value chain emissions	A value chain is a model used in business to describe a series of coordinated activities required to deliver a product or service.

GLOSSARY OF ACRONYMS

ACR	The American Cabon Registry
AD	Activity data
CAR	The Climate Action Reserve. Previously the California Climate Action Registry.
CEM	Continuous emissions monitors
CO_2e	Carbon-dioxide equivalent
EEIO	Environmentally extended input-output models
EF	Emission factor
EOL	End of Life
EU ETS	European Union Emissions Trading Scheme.
GHG	Greenhouse gas. This term usually is used to refer to the collection of all six types of GHGs regulated by the Kyoto Protocol (CO_2, CH_4, N_2O, SF_6, PFCs and HFCs)
GHGP	The Greenhouse Gas Protocol.
GS	Gold Standard
GWP	Global warming potential
IPCC	The United Nations Intergovernmental Panel on Climate Change.
LCA	Life cycle analysis
LSE	Load serving entity
PPA	Power purchase agreement
RE	Renewable energy
RECs	Renewable energy credits
RPS	Renewable Portfolio Standard
MtCO_2e	Metric tonne CO_2 equivalent.
TCR	The Climate Registry
T&D	Electricity transmission and distribution system
UNFCCC	United Nations Framework Convention on Climate Change, the multilateral environmental agreement to address the risk of global climate change.
VCS	Verified Carbon Standard, a program of VERRA.
WRI	World Resources Institute

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1. INTRODUCTION

As a consequence of significant and growing stakeholder and regulatory interest in “climate disclosure” and transparent accounting of corporate scope 1, 2, and 3 emissions, there is a growing need for electric companies and combined electric and natural gas utilities to conduct technically grounded GHG emissions accounting and reporting.

To address this need, EPRI’s program on Energy, Environmental, and Climate Policy Analysis (P201) in 2021 completed a supplemental project focused on transferring in-depth technical knowledge and expertise related to scope 1 and 2 emission accounting and reporting. In 2023, EPRI launched a follow-up project focused on “*Scope 3 Greenhouse Gas Emissions Accounting for Electric Companies and Combined Utilities*” to provide technical insight into accounting and reporting for the 15 scope 3 emissions accounting categories. During the course of completing these two projects, EPRI identified a variety of key issues and special topics associated with GHG accounting for electric companies and combined utilities that require deeper understanding and investigation.

To address these key issues more directly, EPRI launched a follow up supplemental project in 2024 on Special Topics in Greenhouse Gas Emissions Accounting for Electric Companies and Combined Utilities. This report is a compendium of briefing papers and Frequently Asked Questions (FAQ) developed to support a series of webcasts EPRI hosted in 2024 and 2025 as part of this supplemental project. This technical transfer project focused specifically on improving participants’ understanding of (i) accounting and reporting for electricity and natural gas transmission and distribution related emissions in scope 1, 2, and/or 3; (ii) location- and market-based approaches to GHG accounting for scope 2 indirect emissions; (iii) GHG inventory base year recalculation methods and approaches; and (iv) scope 3 insetting.

Table 1-1 provides a brief summary of each of these briefing papers. Chapters 2-5 of this report are copies of the four original webcast briefing papers developed for this project. The original briefing papers have been reformatted to integrate them together into this EPRI technical update report but otherwise reflect the original content of each briefing. Table and figure numbers have been retained as presented in the original briefing papers.

In addition, the project also organized and hosted a one-day technical workshop to explore methods and approaches that potentially could be used by electric companies to determine the “materiality” of GHG emissions sources to be included in their annual GHG emissions inventories.

Table 1-1. Summary of EPRI Special Topics Project Technical Webcasts and Briefing Papers.

Webcast	Topic & Summary
01	**Accounting and reporting for electricity and natural gas transmission and distribution related emissions in scope 1, 2, and 3** This brief explores existing guidance related to corporate GHG accounting for electricity transmission and distribution (T&D) systems and natural gas pipelines. Many voluntary and mandatory GHG accounting frameworks exist in the U.S. and internationally that provide guidance to companies related to the accounting and reporting of their GHG emissions. However, these frameworks often use varying GHG accounting methods and reporting guidelines, leading to ambiguous and misaligned instructions. Furthermore, these frameworks are intentionally broad and often are applied generically across sectors. This results in technical gaps within sectors, particularly concerning GHG emissions from electricity T&D systems and natural gas pipelines.
02	**Location- and market-based accounting for scope 2 indirect emissions** This brief explores location- and market-based approaches to accounting and reporting for scope 2 emissions. It explores the selection and use of emission factors (EFs) related to the location- and market-based methods, and GHG accounting issues associated with renewable energy (RE) purchasing claims associated with the market-based approach. The GHG Protocol's (GHGP) Scope 2 Guidance (2015)[1] (referred to as the 'Scope 2 Guidance') provides technical guidance to entities on how to account and report scope 2 emissions. As part of this guidance, the GHGP has defined two approaches – the "location-based" and "market-based" methods – to account and report scope 2 emissions associated with purchased electricity. The Scope 2 Guidance also requires entities to report using both location- and market-based methods if an entity operates in a region in which market-based energy procurement contracts (e.g., Power Purchase Agreements (PPAs)) and/or environmental attribute certificates (EACs) are used, such as in the United States where markets for renewable energy certificates (RECs) exist.
03	**Base year recalculation methods and approaches** This brief explains: (i) Corporate GHG inventory recalculation practices; (ii) The importance of recalculating base year and historic emission inventories; (iii) Events that do and do not trigger recalculations; and (iv) Approaches that can be used to recalculate base year and historic emissions. A base year in a GHG emissions inventory is a reference point in the past to which current emissions can be compared. Recalculating base year and historic GHG emission inventories refers to the process of re-estimating a reporting company's historic emissions due to structural changes in a corporate entity's organizational or operational boundaries or other "significant" changes.

[1] WRI/WBSCD GHG Protocol Scope 2 Guidance (2015).

Table 1-1 (continued). Summary of EPRI Special Topics Project Technical Webcasts and Briefing Papers.

Webcast	Topic & Summary
04	**Insetting: claiming avoided greenhouse gas emissions and enhanced removals associated with value chain interventions** This brief focuses on the concept of GHG emissions "insetting," and addresses the following topics: (i) Explains how insetting may be used to quantify avoided GHG emissions or enhanced removals associated with scope 3 value chain interventions; (ii) Discusses how some parties have proposed integrating insetting into existing GHG accounting guidance; (iii) Illustrates insetting using Nestle's Supply Chain (Scope 3) and Sourcing Landscape Removals Framework as an example; and, (iv) Identifies challenges to insetting, and the potential risks to companies pursuing insetting interventions.

2. ACCOUNTING AND REPORTING FOR ELECTRICITY AND NATURAL GAS TRANSMISSION AND DISTRIBUTION-RELATED GHG EMISSIONS IN SCOPE 1, 2, AND 3

Introduction

This is the first brief in a series to accompany a set of EPRI-sponsored technical webcasts designed to highlight and explore key technical issues and accounting methods associated with corporate greenhouse gas[2] (GHG) emissions accounting and reporting**.** These webcasts are part of an EPRI supplemental research project on "Special Topics in GHG Emissions Accounting for Electric Companies and Combined Utilities." **This brief explores existing guidance and presents expert guidance related to corporate GHG accounting for electricity transmission and distribution (T&D) systems and natural gas pipelines.**

Many voluntary and mandatory GHG accounting frameworks (aka protocols) exist in the U.S. and internationally, guiding companies in the accounting and reporting of their GHG emissions. However, these frameworks often use varying GHG accounting methods and reporting guidelines, leading to ambiguous and misaligned instructions. Furthermore, these frameworks are intentionally broad and are often applied generically across sectors. This results in technical gaps within sectors, particularly concerning GHG emissions from electricity T&D systems and natural gas pipelines.

To improve understanding of GHG emissions accounting and reporting for common carrier energy infrastructure, EPRI and GHGMI recently published a comprehensive report titled "*Greenhouse Gas Emissions Accounting for Common Carrier Energy Infrastructure: Electricity Transmission and Distribution Systems and Natural Gas Pipelines*." This EPRI report summarizes existing GHG accounting guidance related to common carrier energy infrastructure, both for voluntary and mandatory GHG accounting and reporting purposes, based on the GHG Protocol's Corporate Standard and the Corporate Value Chain (Scope 3) Standard (henceforth referred to as the Corporate Standard and Scope 3 Standard, respectively).

In this context, the term "common carrier" refers to a company that owns the transportation or transmission infrastructure, such as natural gas pipelines and electricity T&D systems. However, these companies do <u>not</u> necessarily own the natural gas or electricity passing through these systems. When acting as a common carrier, companies provide a transportation or transmission service to electricity generators and/or natural gas producers.

[2] The term Greenhouse Gas (GHG) refers to gases including carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and nitrogen trifluoride (NF_3).

Defining the Reporting Boundaries

The Corporate Standard delineates corporate inventory reporting boundaries based on *direct* and *indirect* emissions sources (from the reporting company's perspective). These emission sources are categorized into three emission inventory scopes highlighted in Table 2-1.

Table 2-2. Corporate GHG emissions accounting[3] scopes and descriptions

Scope	Scope Description
Scope 1	Direct GHG emissions that result from a company's owned or controlled equipment, facilities, or operational activities that emit (or remove) GHGs.
Scope 2	Scope 2 accounts for indirect GHG emissions from purchased or acquired electricity, steam, heating, and cooling that are generated by another entity and consumed by the reporting company. Also, generally includes emissions associated with electric company T&D system "line losses."
Scope 3	Scope 3 emissions are all other indirect GHG emissions not included in scope 2. There are 15 categories of "upstream" and "downstream" scope 3 accounting categories.

A complete corporate GHG inventory includes all scope 1 emissions and, depending on the reporting program requirements and/or company's goals, all relevant scope 2 emission sources. Scope 3 emissions currently are considered optional for voluntary reporting, but stakeholders, including some regulatory bodies,[4] are increasingly requesting information and data related to companies' scope 3 emissions.

The following sections identify and describe typical GHG emission sources associated with the operation of company-owned electric T&D systems and natural gas pipelines falling within each emission scope.

Scope 1 Direct Emissions

Direct emissions, referred to as scope 1, result from a company's owned or controlled equipment, facilities, or operational activities that emit (or remove) GHGs. For example, an electric company's scope 1 emissions may include emissions associated with electricity generation, natural gas leaks from company-owned pipelines, fugitive SF_6 emissions from company-owned switchgear, and mobile emissions associated with company-owned vehicles.

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[3] As defined by the GHG Protocol Corporate Standard (2004).

[4] For example, the federal Securities and Exchange Commission's Enhancement and Standardization of Climate-Related Disclosures for Investors, Final Rule published 3/8/2024. See 17 CFR Parts 210-249. Also, California's law SB-253 (GHG Acct) requires companies operating in CA with more than $1B in annual gross revenue to account and disclose scopes 1, 2 & 3 emissions from global operations. SB-261 (Carbon Disclosure) requires public and privately-owned California-based companies – with more than $500 million in annual gross revenues – to disclose climate-related financial risks.

Scope 2 Indirect Emissions from Purchased Electricity, Heat, Steam, and Cooling

Scope 2 emissions account for emissions from the generation of electricity, heat, steam, and cooling that is purchased or acquired (i.e., brought into the organization boundary of the reporting company).[5] Within scope 2 emissions, there are two categories relevant to electric companies and combined utilities: (i) indirect emissions from electricity, steam, heating, and cooling purchased or acquired and consumed by the reporting company; and, (ii) indirect emissions associated with electricity "consumption" associated with transmitting electricity across company-owned T&D systems.

Primarily, scope 2 accounts for indirect emissions from electricity, steam, heating, and cooling that are generated by another entity and consumed by the reporting company to operate its buildings and equipment connected to the electric grid. These indirect emissions occur outside of the organizational boundary of the reporting company because they are directly emitted by a power plant owned or operated by another party. An electric company reporting scope 2 emissions would account for GHG emissions associated with the electricity, steam, heating, and cooling they purchase (or acquire) from other entities and consume to operate buildings and infrastructure. These scope 2 emissions tend to be relatively small for electric companies because they are associated with electricity that the reporting electric company purchases externally from another electric utility to provide electricity to buildings, and other infrastructure, they may own but which are located outside of their service territory.

The second type of scope 2 emissions is unique to electric companies that own and operate T&D systems, and for some types of electric companies these emissions may comprise a large share of their overall GHG emissions. When electricity is transmitted from generation facilities to grid-connected end-users through T&D systems, a portion of the electricity is "consumed" as it is transported across the T&D systems' wires and equipment. This consumption is referred to as "T&D line losses."[6] Within a GHG inventory, a company may categorize the indirect emissions associated with these line losses as scope 2 if they own and/or operate the T&D system, or as scope 3 emissions if they do not. Similarly, electric companies may account for emissions from T&D line losses associated with wholesale power purchases within scope 2 if they own and/or operate the T&D system or scope 3 if they do not.

However, vertically integrated power companies – and other types of electric companies that own electricity generation and integrated T&D systems – typically report as scope 1 the emissions associated with the gross amount of electricity they generate which accounts for the downstream T&D line losses. Consequently, these entities do not separately report emissions associated with the T&D lines losses as scope 2 because these emissions are already accounted for in their scope 1 emissions. Electricity companies that generate and supply 100% of their operational electricity, steam, heating, and cooling through their own T&D systems would not

[5] Identifying Scope 2 Emissions and Setting the Scope 2 Boundary, Scope 2 Guidance, (GHG Protocol, 2016)

[6] Typically, in the United States, T&D line losses are between three and seven percent (3-7%) of the total amount of electrical energy transmitted and/or distributed across a power system.

report any scope 2 emissions, as these emissions would be accounted for within scope 1 as direct emissions.

Corporate Structures and Accounting for Indirect T&S Emissions

The classification of T&D line losses within GHG accounting scopes is influenced by the electric company's corporate structure. Table 2-2 summarizes the GHG emissions accounting for T&D line losses for common types of electric companies, including**: vertically integrated companies** (e.g., investor-owned utilities, and some large public power agencies)**, generation and transmission co-ops (G&Ts), transmission and/or distribution companies** (i.e., "wires-only" companies), and **independent power producers (IPPs).**

Table 3-2. T&D-related greenhouse gas emissions accounting by type of electric company

Corporate Structure	Does the GHG Inventory Include Scope 2 T&D losses?
Vertically Integrated Electric Company	1. **No** – for self-generated power. These emissions are accounted for in Scope 1. T&D losses are not indirect for the company. 2. **Yes** – for wholesale power purchased from other parties and transmitted and/or distributed (e.g., wheeled) across the vertically integrated company's T&D system.
Generation and Transmission Co-op	**Same as above.** But line losses are limited to the bulk transmission system only, unless the G&T also owns/operates the local distribution system(s).
Transmission and/or Distribution Company	**Yes**. The company's emissions inventory would include scope 2 indirect GHG emissions associated with T&D line losses for all electricity flowing through the T&D company's system.
Independent Power Producer	**No**. The IPP does not own or operate T&D equipment. Any indirect emissions associated with T&D line losses from purchased power for "own" use of electricity are categorized as scope 3.

If companies purchase electricity and then transmit it across their lines to another party (i.e., "wheel" it), the associated T&D losses should be classified as scope 2 indirect emissions.[7]

"Wires-only" companies account for the indirect GHG emissions associated with T&D line losses as scope 2 emissions. Companies that only own and operate power generation facilities, such as IPPs, typically do not have scope 2 emissions associated with T&D losses, but they may have other scope 2 emissions associated with the energy they purchase and consume from third parties to operate their buildings and facilities. These entities account for all scope 1 emissions

[7] The rationale here is that accounting for the indirect emissions associated with losses that occur in the process of wheeling wholesale power within scope 2 is valuable as it distinguishes an emissions source that the wheeling electric company has a greater ability to impact (e.g., through improvements to the T&D system).

from their generation facilities, as they do not own or operate any T&D infrastructure. Any emissions from T&D losses associated with electricity purchased from third parties would be categorized in scope 3.

Scope 3 Emissions Accounting (aka Value Chain Accounting)

Scope 3 emissions refer to all other indirect emissions not included in scope 2. The Scope 3 Standard categorizes value chain indirect emissions into 15 categories of *upstream* and *downstream* emission sources from the perspective of the reporting company. Upstream activities involve a company's supply chain and include inputs to a company's production. Downstream emissions relate to activities associated with selling goods and services to intermediate and end-use customers and may include emissions associated with a reporting company's franchises and investments. Downstream emissions also include emissions from products that are distributed but not sold (i.e., distributed without receiving payment). The Scope 3 Standard also includes any other indirect emissions not included in scope 1 and scope 2 due to the selected consolidation approach (e.g., leased assets, franchises, investments).

Emission Sources: Electricity T&D Systems

Option 2: Report Outside of the 15 Categories, but within Scope 3

Alternatively, common carriers could provide GHG-related information about their operations and emissions under the Scope 3 Standard's guidance for *optional reporting*. The Scope 3 Standard provides a comprehensive list of *optional* information that reporting companies *can* report as supplemental information or as an addendum to the scope 3 emissions inventory, including:

- **Emissions from scope 3 activities not included** in the list of scope 3 categories (e.g., transportation of attendees to company-hosted conferences/events), reported separately, such as in a different scope 3 category;
- **Qualitative information** about emission sources that are not quantified;
- Relevant **performance indicators** and intensity ratios related to operations; or
- **Information on supplier's** or partner's engagement, data availability, and performance.

Reporting companies can choose to provide some or all of the information bulleted above related to the ambiguous emissions sources (shown in Tables 3 and 4) outside of their scope 3 inventory.

Option 3: Justify and Disclose Any Exclusions

Lastly, companies can choose to exclude accounting and reporting of emissions associated with any *ambiguous* boundary (shown in Tables 3 and 4) due to a lack of guidance from the Scope 3

Standard. Any such exclusion(s) should be accompanied by a justification by the reporting company for the exclusion in their GHG emissions inventory report. This option can be supplemented by the optional GHG-related data reporting identified in Option 2.

Table 2-4 summarizes the emission sources related solely to the operations of T&D systems and categorizes them according to the GHG Protocol and Scope 3 Standard. Other emission sources associated with managing T&D systems are dependent on other operation-specific activities and are out of the scope of this brief (e.g., direct emissions from stationary and mobile combustion, indirect emissions from waste disposal, and purchased goods).

Emission Sources: Natural Gas Pipelines

The GHG Protocol does not provide specific guidance and information for the treatment of indirect emission sources occurring in the value chain of natural gas pipeline owners when the owner does not own or control the natural gas flowing through their systems.

In the absence of specific guidance, the existing guidance for electric T&D systems can be interpreted as being analogous to natural gas pipelines as both types of infrastructure operate as common carriers for the distribution of undifferentiated energy commodities.

Table 2-4 summarizes emission sources according to the categorization by the GHG Protocol and the Scope 3 Standard for the operations of natural gas pipeline systems (e.g., fuel or electricity used by equipment within the pipeline network to move natural gas). Other emission sources may apply and are associated with managing pipelines and other operation-specific activities that are beyond the scope of this brief.

Options to report Indirect Emissions from Common Carrier Infrastructure

Accounting for and reporting emissions associated with products that are distributed but not sold, such as natural gas and electricity transported via common carrier infrastructure, presents challenges for owners of this type of infrastructure because the available GHG accounting guidance for addressing this situation is not definitive.

This section presents three potential approaches for electric companies and combined utilities to account for and report GHG emissions associated with the transportation of products distributed but not sold via common carrier infrastructure, based on interpretations of the GHG Protocol.

Option 1: Expand the Boundary and Report Ambiguous Emission Sources within Scope 3, Categories 3 and 11

To account for and report emissions from electricity and natural gas products that are distributed but not sold (i.e., the *ambiguous* emission sources identified in Tables 2-3 and 2-4), common carriers can establish their reporting boundaries to include *all* electricity and natural gas the company transports and delivers within its value chain. If a T&D "wires-only" company takes this approach, it may report indirect emissions from these sources under scope 3, category 3 (fuel and energy-related emissions). If a common carrier natural gas pipeline adopts this approach, then these emissions could be reported under scope 3, category 11 (use of sold products). For example, a natural gas pipeline owner would estimate and report end-use emissions from the combustion of the total amount of natural gas transported through their systems in category 11.

Option 2: Report Outside of the 15 Categories, but within Scope 3

Alternatively, common carriers could provide GHG-related information about their operations and emissions under the Scope 3 Standard's guidance for *optional reporting*. The Scope 3 Standard provides a comprehensive list of *optional* information that reporting companies *can* report as supplemental information or as an addendum to the scope 3 emissions inventory, including:

- **Emissions from scope 3 activities not included** in the list of scope 3 categories (e.g., transportation of attendees to company-hosted conferences/events), reported separately, such as in a different scope 3 category;
- **Qualitative information** about emission sources that are not quantified;
- Relevant **performance indicators** and intensity ratios related to operations; or
- **Information on supplier's** or partner's engagement, data availability, and performance.

Reporting companies can choose to provide some or all of the information bulleted above related to the ambiguous emissions sources (shown in Tables 3 and 4) outside of their scope 3 inventory.

Option 3: Justify and Disclose Any Exclusions

Lastly, companies can choose to exclude accounting and reporting of emissions associated with any *ambiguous* boundary (shown in Tables 3 and 4) due to a lack of guidance from the Scope 3 Standard. Any such exclusion(s) should be accompanied by a justification by the reporting company for the exclusion in their GHG emissions inventory report. This option can be supplemented by the optional GHG-related data reporting identified in Option 2.

Table 2-4. GHG emission sources for T&D owners that (A) generate and/or purchase electricity vs (B) a T&D owner that does not generate or purchase the electricity

Emission Sources	A. T&D owner generates and/or purchases the electricity	B. T&D owner does not generate or purchase the electricity
Direct Emission Sources		
Scope 1, fugitive: SF_6 emissions from T&D systems	Yes for both T&D Owners A & B	

Scope 1: other direct: emissions from T&D-related operations (e.g., from stationary combustion, fugitive)	Yes for both T&D Owners A & B	
Upstream Indirect Emission Sources		
Scope 2: purchased or acquired electricity, heat, steam, and cooling	Yes, only for emissions from non-self-generated electricity "consumed" by the T&D systems as line losses.	Yes, for emissions associated with electricity "consumed" by the T&D systems as line losses.
Scope 3, category 1: purchased goods and services	Yes, upstream emissions related to purchased fluorinated gases (e.g., SF_6 refilling), outsourced maintenance services, etc.	
Scope 3, category 2: capital assets	Yes, upstream emissions related to purchased capital assets (e.g., wiring, poles).	

Table 2-3 (continued). GHG emission sources for T&D owners that (A) generate and/or purchase electricity vs (B) a T&D owner that does not generate or purchase the electricity

Emission Sources	A. T&D owner generates and/or purchases the electricity	B. T&D owner does not generate or purchase the electricity
Scope 3, category 3, all upstream emissions from: a. Purchased fuels b. Purchased electricity c. T&D losses d. Purchased electricity sold to end-users	**a**. Yes, purchased fuel combusted at T&D sites. **b.** Yes, purchased and consumed electricity (i.e., line losses) that is not self-generated (excluding combustion). **c.** Yes, line losses in T&D systems that are not owned/operated by the reporting organization.[8] **d.** Yes, emissions from purchased electricity that is sold to end-users.	**a**. Yes, purchased fuel combusted at T&D sites. **b.** Yes, purchased and consumed electricity (i.e., line losses) that is not self-generated (excluding combustion). **c.** Yes, line losses in T&D systems that are not owned/operated by the reporting organization.[9] **d. Ambiguous for electricity that is transmitted via common carriers.** Not directly addressed by GHG Protocol standards.[10]
Scope 3, category 5: waste generated from operations	Yes, for any waste disposed of and sent to third-party treatment facilities.	
Downstream Indirect Emission Sources		
Other scope 3 categories	Scope 3 categories that may be applicable include end-of-life treatment of sold products (category 12), and investments (category 15).	

[8] Line loss emissions that occur prior to entering T&D system they own. For example, when battery energy storage systems (BESS) losses occur before power is metered and injected into their T&D systems.

[9] Ibid.

[10] The Climate Registry's Electric Power Sector Protocol addresses this scenario. Refer to https://theclimateregistry.org/wp-content/uploads/2022/11/Protocol_062509.pdf

Table 2-5. Relevant emission sources for (A) natural gas (NG) pipeline owners that own, control and/or purchase NG vs (B) pipeline owners that do not own, control, or purchase NG.

<table>
<tr><th>Emission Sources</th><th>A. NG pipeline owns, controls, and/or purchases the NG</th><th>B. NG pipeline does <u>not</u> own, control, or purchases NG</th></tr>
<tr><td colspan="3"><u>Direct</u> Emission Sources</td></tr>
<tr><td>Scope 1, fugitive: CH_4 emissions from pipeline systems</td><td colspan="2">Yes.</td></tr>
<tr><td>Scope 1, other direct: emissions from pipeline-related operations (e.g., stationary combustion, fugitive)</td><td colspan="2">Yes.</td></tr>
<tr><td colspan="3">Upstream <u>Indirect</u> Emission Sources</td></tr>
<tr><td>Scope 2: purchased or acquired electricity, heat, steam, and cooling</td><td colspan="2">Yes, only for emissions from non-self-generated electricity.</td></tr>
<tr><td>Scope 3, category 1: purchased goods and services</td><td>Yes, upstream emissions from purchased natural gas for distribution.</td><td>Ambiguous for natural gas transported by common carriers; it is not directly addressed by the Scope 3 Standard.</td></tr>
<tr><td>Scope 3, category 2: capital assets</td><td colspan="2">Yes, upstream emissions from purchased capital assets (e.g., infrastructure).</td></tr>
<tr><td>Scope 3, category 3: all upstream emissions from:
a. Purchased fuels
b. Purchased electricity
c. T&D losses
d. Purchased electricity sold to end-users</td><td colspan="2">a. Fugitive emissions related to purchased fuel combusted on site remain ambiguous.[11] Non-purchased fuels fugitive emissions are not directly addressed by the Scope 3 Standard.
b. Purchased electricity that is not self-generated (not including combustion).
c. Not applicable.
d. Not applicable.</td></tr>
<tr><td>Scope 3, category 5: waste generated from operations</td><td colspan="2">Yes, for any waste disposed of and sent to third-party treatment facilities.</td></tr>
<tr><td colspan="3">Downstream <u>Indirect</u> Emission Sources</td></tr>
<tr><td>Scope 3, category 11: Use of sold products</td><td>Yes, downstream emissions associated with natural gas sold to end-users.</td><td>Ambiguous for natural gas transported by common carriers; it is not directly addressed by the Scope 3 Standard.</td></tr>
<tr><td>Scope 3, other categories</td><td colspan="2">Scope 3 categories that may be applicable include end-of-life treatment of sold products (category 12) and investments (category 15).</td></tr>
</table>

[11] Although this category is for "purchased fuels," pipeline leaks could be interpreted as analogous to T&D line losses (reported under category 3, activity c).

3. LOCATION- AND MARKET-BASED ACCOUNTING FOR SCOPE 2 EMISSIONS

Introduction

This brief is the second in a series that accompanies a set of EPRI-sponsored technical webcasts designed to highlight and explore key technical issues and accounting methods associated with corporate greenhouse gas (GHG) emissions accounting and reporting**.**

This brief explores location- and market-based approaches to accounting and reporting for scope 2 emissions. It explores the selection and use of emission factors (EFs) related to the location- and market-based methods, and GHG accounting issues associated with renewable energy (RE) purchasing claims associated with the market-based approach.

Scope 2 Emissions

Scope 2 emissions include the indirect GHG emissions from purchased or acquired **electricity**, **steam**, **heating**, and **cooling**[12] that are generated by another entity and consumed by the reporting company.[13] Additionally, scope 2 includes emissions associated with "line losses" across a reporting company's transmission and distribution (T&D) systems.[14]

Many end-use electricity customers, particularly consumer-oriented large commercial and industrial (C&I) customers, want to know the GHG emissions intensity (i.e., tCO_2e/MWh) of the electricity delivered by their local electric utility to calculate and report their scope 2 emissions, and develop plans to reduce them. Unfortunately, it is impossible to track electricity generated by specific power plants through the electric power grid and delivered to a specific end-use customer.[15]

[12] For the purposes of this briefing and for the sake of simplicity, the term "electricity" is used as a catch-all word that refers to electricity, steam, heating, and cooling.

[13] These indirect emissions are limited to only those resulting from the generation of the electricity, as opposed to broader upstream indirect emissions.

[14] When a reporting company purchases electricity to meet load or to resell to end-users, the GHG emissions associated with the upstream power generation are scope 3 emissions which are outside of the scope of this brief. For more information on scope 3 GHG emissions accounting, see Scope 3 Greenhouse Gas Emissions Accounting for Electric Companies and Combined Utilities: A Compendium of Technical Briefing Papers and Frequently Asked Questions, EPRI, Palo Alto, CA 2023. 3002029198.

[15] In limited cases, it may be possible to identify specific power plants that supply electricity to end-use customers (e.g., "island" power systems and microgrids), but in most cases the electricity delivered to consumers is undifferentiated "grid power."

The GHG Protocol's (GHGP) Scope 2 Guidance (2015)[16] (referred to as the Scope 2 Guidance) provides technical guidance to entities on how to account and report scope 2 emissions. As part of this guidance, the GHGP has defined two approaches – the "location-based" and "market-based" methods – to account and report scope 2 emissions associated with purchased electricity. The Scope 2 Guidance also requires entities to report using both location- and market-based methods if an entity operates in a region in which market-based energy procurement contracts (e.g., Power Purchase Agreements (PPAs)) and/or environmental attribute certificates (EACs) are used, such as in the United States where markets for renewable energy certificates (RECs) exist.

The location-based approach applies *grid average EFs*[17] to estimate and report scope 2 emissions associated with purchased electricity. This approach is not based on tracking electricity from a specific power plant to the end-user as it applies a power grid-level average to estimate indirect emissions from electricity consumption. Typically, this is a generation-weighted EF averaging all GHG emissions (or CO_2 only) associated with the power generation resources operating in a defined grid region for a specified period of time (e.g., calendar year). Annual grid average EFs for the entire U.S. disaggregated into 27 sub-regions are available in the Emissions & Generation Resource Integrated Database (eGRID) maintained by the U.S. Environmental Protection Agency.[18] Electric companies also use annual grid average EFs to estimate and report scope 2 emissions associated with electricity they buy from others to power their own operations and for other GHG accounting purposes.

Market-based approaches attempt to allocate GHG emissions from specific power plants to specific end-users. While several different approaches to allocate power system GHG emissions to end-users have been developed in recent years[19], none of them can overcome the physical reality of how electricity enters a grid and becomes indistinguishable from the electricity on that grid system, which critics argue erodes the validity of the emissions allocation. For example, there currently is not a widely agreed upon approach to calculate "load-based" or "consumption-based" EFs, which attempt to allocate power system emissions to end-users.[20] As covered in this brief, this is the fundamental critique of market-based approaches used to account and report scope 2 emissions.

[16] WRI/WBSCD GHG Protocol Scope 2 Guidance (2015).

[17] Some RTOs and ISOs publish GHG intensity data for their operating footprint. The US EPA's eGRID program also publishes emission intensities for grid sub-regions of the U.S. One challenge with using eGRID and other EF databases is that publishing typically lags one or more years behind the current reporting period.

[18] https://www.epa.gov/egrid .

[19] For example, FlexiDAO, Granular Energy, Kevala, Singularity, and WattTime.

[20] For a summary of load-based accounting approaches, see *Methods to Account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases*, EPRI, Palo Alto, CA: 2019. 3002015044. https://www.epri.com/research/products/000000003002015044 .

Procuring Renewable Energy and Environmental Attribute Certificates (EACs) to Reduce Scope 2 Emissions

To drive rapid deployment of RE and decarbonization, many states have adopted regulatory programs establishing renewable portfolio standards (RPS), clean energy standards (CES), and other programs requiring electric companies to procure and track RE generation and other types of "clean energy." Most RPS programs allow electric utilities and other power generators to create and trade RECs to demonstrate RPS compliance. Typically, RECs record the generation of one MWh of electricity by a specified "renewable" resource (e.g., wind or solar), as defined by the specific RPS program. In recent years, many companies in the U.S. and internationally have focused on buying RE and RECs to reduce their reported scope 2 emissions and claim scope 2 emission reductions.

Scope 2 emissions associated with purchased electricity often are a comparatively large source of GHG emissions for C&I customers, yet it can be challenging for these customers to reduce these emissions because they are not under their direct control. The only direct actions most electricity customers can take to reduce their scope 2 electricity-related emissions are to reduce their energy consumption
(e.g., by installing energy efficiency upgrades) and/or install behind-the-meter RE, such as rooftop solar. These approaches often can be used to reduce some of a company's scope 2 emissions, but despite these efforts, many companies will continue to consume large amounts of electricity and report the associated scope 2 emissions. In the absence of being able to take direct action to reduce their scope 2 emissions more significantly, many companies have focused on procuring RE and RECs to report lower scope 2 emissions and claim scope 2 emission reductions. Recently, a few leading sustainability-oriented technology companies have started to procure "24/7 carbon-free energy" (24/7 CFE) to reduce their reported scope 2 emissions and claim scope 2 emission reductions.[21]

Existing GHG accounting protocols (e.g., the GHGP and The Climate Registry) and practices provide both a strong incentive and a way for companies to procure RE and RECs to claim a reduction in the scope 2 emissions they report associated with the electricity they buy and consume. Under existing protocols, companies can report their electricity-related scope 2 emissions using either a market-based and/or a location-based method, and apply GHG EFs associated with the selected method. Using the market- based method, companies that procure RE and/or purchase RECs equal to their actual grid electricity consumption may be permitted to report zero GHG emissions. In this scenario, a company is permitted by the GHGP to apply a 0 tCO_2/MWh EF to electricity consumed even if grid electricity is supplied by fossil-fired power generation.

[21] For more information about 24/7 CFE, see 24/7 Carbon-free Energy: Matching Carbon-free Energy Procurement to Hourly Electric Load, EPRI, Palo Alto, CA 2022. 3002025290.

Quantifying Scope 2 Emissions

To estimate scope 2 emissions associated with purchased and consumed electricity and other energy sources, reporting companies typically multiply the quantity of energy consumed (e.g., MWh, BTU) by an appropriate EF (i.e., tCO_2/MWh). Equation 1 illustrates how a reporting company can use activity data (AD) and relevant EFs to calculate the total emissions associated with the electricity they purchase.

$$\textit{Activity data}\ (\text{MWh}) \times \textit{Emission factor}\ (\text{tCO}_2\text{e/MWh}) = \textit{GHG emissions}$$

Equation 1. Calculating GHG Emissions from Purchased Electricity

The Scope 2 Guidance introduced **a dual-reporting mechanism**, exclusive to scope 2 reporting, for companies that operate in markets with contractual instruments (see key terms for definition). The dual-reporting is based on using both the **location- and market-based methods**, and, if applicable, companies must estimate and report their scope 2 emissions using both methods. The location- and the market-based approaches used to quantify scope 2 emissions are distinguished by the EF applied to the consumed electricity AD. The dual reporting mechanism applies to all types of purchased or acquired energy: **electricity**, **steam**, **heating**, and **cooling** provided that the reporting company operates in markets with contractual instruments for these types of energy resources (e.g., renewable natural gas or renewable heating certification schemes that exist in U.S. states[22]).

Location-Based Method

The location-based method reflects the average GHG emissions intensity of power generation on a power grid where energy consumption occurs, using mostly grid-average emissions data. This is an EF that reflects the physical flow of electricity in the regional grid and represents the physical reality of electricity generation, transmission, and distribution. This is an appropriate proxy measure for the electricity “consumed” by an end-user. To report scope 2 emissions using the location-based method, a reporting company needs to identify and select a temporally and geographically appropriate EF based on the recommended Scope 2 Guidance EF hierarchy shown in Table 3-1.

For example, a company purchasing electricity from a utility with a service territory in the metro-area of Houston, TX could use a national average grid EF or the company could use a more geographically refined EF that represents the electricity generation resources injecting power to the U.S. EPA eGRID EF for the ERCOT region.[23]

[22] Markets for steam or cooling contractual instruments may exist but the authors could only identify examples of market instruments that exist for electricity (RECs, GOs etc) and heating, for example see https://www.ekoenergy.org/wp-content/uploads/EKOenergy-criteria-for-heat-and-cold-English.pdf, or https://www.greengas.org.uk/ also referenced within question 53 of the RE100 guideline FAQs https://www.there100.org/sites/re100/files/2024-02/RE100%20FAQs%20-%20Feb%202024.pdf.

[23] ERCOT is referred to as ERCT in eGRID’s subregional nomenclature.

Table 3-6. Hierarchy of Location-based Emission Factors[24]

Purchased Electricity Emission Factor Type (location-based)	Example
Direct line (where applicable) If purchased electricity is supplied via direct line (i.e., a direct transmission line installed from a generation source to a single facility or group of facilities).	Supplier- or fuel-specific
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**. EFs should reflect net physical energy imports/exports across the grid boundary.	U.S. EPA eGRID
National production emission factor 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. These EFs provide no adjustment for physical energy imports or exports and may not be representative[25] of energy consumption area.	International Energy Agency (IEA); national GHG emissions inventories

Table 3-2 shows how an example natural gas utility can calculate their location-based GHG emissions. For this example, let us assume natural gas utility and reporting company consumed 450,000 kWh of electricity from the grid in 2023 at their corporate offices, and purchased 300 MMBtu of heating[26] from district heating. Their offices are located in Boise, Idaho and are within the WECC Northwest eGRID subregion. The eGRID EFs for the most recent eGRID dataset is the eGRID2022, and the CO_2 EF[27] is 602.1 lb. CO_2/MWh. The inventory compiler uses the U.S. EPA Emission Factors Hub[28] to locate an EF for purchased heating, which is 66.33 kg CO_2/MMBtu. Their annual emissions from purchased electricity and heating are calculated as shown in Table 2.

[24] Adapted from WRI/WBSCD GHG Protocol Scope 2 Guidance (2015).

[25] Exceptions may include island nations and countries with little to no imports or exports.

[26] In this example, district heating is assumed to be provided by a local distribution energy system.

[27] For simplification purposes only, CH_4 and N_2O are not included in this example.

[28] Table 7 from https://www.epa.gov/system/files/documents/2024-02/ghg-emission-factors-hub-2024.pdf

Table 3-2. An Example of Calculating Location-based Emissions

Scope 2 Activity Type	Activity Data (AD)	Emission Factors (EF)	Type of EF	Emissions Totals
Purchased Electricity	450 MWh	602.1 lb. CO_2/MWh	Subnational Grid Average	**AD x EF** = 270,945 lb. CO_2 x **conversion factor** (1 tonne/2,204.62 lb.) = 122.89 tCO_2
Purchased Heating	300 MMBtu	66.33 kg CO_2/MMBtu	National Average	**AD x EF** = 19,899 kg CO_2 x **conversion factor** (1 tonne/1,000 kg) = 19.89 tCO_2
Scope 2 location-based total			122.89 tonnes CO_2 + 19.89 tonnes CO_2 = **142.78 tCO_2**	

Market-Based Method

While the location-based method reflects the average emission intensity of grid-supplied energy, the market-based method is a mechanism designed to reflect the GHG emissions associated with electricity that end-use customers have procured using power purchase agreements (PPAs) and other types of contractual instruments. In practice, the inclusion of the market-based approach in the GHG Protocol has incentivized corporate electricity consumers to procure RE, and to buy bundled and unbundled[29] RECs to reduce their reported scope 2 emissions and claim scope 2 emission reductions, despite physically consuming electricity from the grid that is (partially) supplied by fossil generation.

Companies also may choose to procure RE by participating in a utility-sponsored "green power" program or by using other specialized tariffs (i.e., 24/7 CFE), rather than procuring RE using a PPA or purchasing RECs. In these cases, the GHGP requires companies to report their market-based scope 2 emission based on the hierarchy of market-based EFs shown in Table 3 and would need to use supplier- or utility-specific emission rates[30], grid residual mix EFs, and/or other location-based EFs.

Using the market-based approach, a reporting company can replace a location-based EF with a "market-based" EF that is designed to reflect the emissions associated with the electricity (e.g., RE) it has procured via PPAs and other mechanisms. In essence, the market-based method allows companies to apply lower GHG-intensive EFs (e.g., 0 tonne CO_2e/MWh) and report zero scope 2 emissions, even if the company does not actually consume the contracted RE.

The use of the market-based approach to quantifying and reporting scope 2 emissions has been justified by the desire to provide ways for companies to reduce emissions associated with their electricity consumption and alter the power generation mix. To report scope 2 emissions using the market-based method, a company must prioritize reporting based upon EACs and contractual instruments before identifying other appropriate EFs to use following the Scope 2 Guidance's EF hierarchy shown in Table 3-3.

[29] "Bundled" RECs refer to RECS that are sold in conjunction with the underlying renewable energy. Unbundled RECs are RECs that are sold separately from the underlying renewable energy.

[30] This includes emissions output rates that consider a supplier's generation portfolio only, or other utility-sponsored "green" tariff programs in regulated markets.

Table 3-3. Hierarchy of Market-based Emission Factors[31]

Purchased Electricity Emission Factor Type (market-based)	Example
Energy attribute certificates or equivalent instruments (unbundled, bundled with electricity, conveyed in a contract for electricity, or delivered by a utility).	RECs, GOs
Contracts for electricity where electricity attribute certificates do not exist or are not required for a usage claim.	PPAs and contracts from specified sources
Supplier/Utility emission rates, such as standard product offer or a different product (e.g., a renewable energy product or tariff), and are disclosed (preferably publicly) according to best available information.	'Green energy' tariffs, emission rate allocated to retail electricity users for the entire energy product generation portfolio
Residual mix (subnational or national) that uses energy production data and factors out voluntary purchases.	Europe's Association of Issuing Bodies (AIB) annual residual mix factors
Other grid-average emission factors (subnational or national)	See location-based hierarchy (Table 1).

Table 3-4 shows how the same natural gas utility used above in the example shown in Table 2 can calculate their market-based GHG emissions. In this case, the natural gas utility selects its electricity supplier-specific EF (e.g., 206 kg CO_2/MWh for 2023), which is published in the supplier's annual environmental reports. In addition, the reporting company procures RECs for 85% of their total electricity consumption (i.e., 1 REC = 1 MWh, hence, they procure 1,233 RECs) and "green heating" certificates for 100% of their heating consumption. Their scope 2 emissions using the market-based approach are calculated as shown in Table 3-4.

Based on this example, it is clear that by using a market-based approach the example company can substantially reduce its reported scope 2 emissions and claim substantial emissions reductions. As shown in Table 3-2, this company would have reported 143 tonnes CO_2 using a location-based approach versus reporting 45 tonnes CO_2 using the market-based approach as shown in Table 3-4.

[31] Adapted from WRI/WBSCD GHG Protocol Scope 2 Guidance (2015).

Table 3-4. Using Market-based EFs to Calculate Scope 2 Emissions

Scope 2 Activity Type	Activity Data (AD)	Emission Factors (EF)	Type of EF	Emissions Totals
Purchased Electricity	1,233 MWh	0 tonnes CO_2/MWh	Energy Attribute Certificate (in this case, RECs)	**AD x EF** = 0 tonnes CO_2
	217 MWh	206 kg CO_2/MWh	Supplier-specific	**AD x EF** = 13.9 tonnes CO_2
Purchased Heating	300 MMBtu	0 tonnes CO_2/MWh	Energy Attribute Certificate	**AD x EF** = 0 tonnes CO_2
			Scope 2 market-based total	**13.9 tonnes CO_2**

Emission Factors

According to the U.S. Environmental Protection Agency (U.S. EPA), EFs are defined as, "a representative value that attempts to relate the quantity of a pollutant released to the atmosphere with an activity associated with the release of that pollutant."[32]

Typically, EFs are expressed as the mass of GHG pollutant per unit of the emission producing activity, such as kg CO_2 emitted per kg of bituminous coal combusted. EFs are expressed in units of mass (e.g., grams, tonnes, pounds) of specific gaseous chemical species, such as CO_2, CH_4, SF_6, and others.

In a GHG emissions inventory reporting companies are required to report emissions for each GHG separately in tonnes and also in tonnes of CO_2 equivalent (CO_2e).[33]

Emission Factors Associated with Purchased Electricity

As discussed previously, the primary difference between location- and market-based approaches is related to the EF used to represent the emissions intensity (tCO_2/MWh) of purchased electricity. Several different types of EFs have been developed that can be used to represent electricity consumed from a power grid to estimate indirect scope 2 GHG emissions.[34] Different types of EFs are described below.

[32] https://www.epa.gov/air-emissions-factors-and-quantification/basic-information-air-emissions-factors-and-quantification

[33] CO_2e is a unit of measurement used to evaluate different GHGs in terms of their Global Warming Potential (GWP) compared to one unit of CO_2 – that is, the "warming effect" of different GHGs relative to CO_2.

[34] For more information about different types of EFs, see *Carbon Pricing and Accounting for Greenhouse Gas Emissions in Wholesale Power Markets: An EPRI Technology Innovation Program Report*. EPRI, Palo Alto, CA: 2024. 3002030179.

Direct Connection EFs

Direct line EFs represent emissions associated with electricity (MWhs) delivered from a power generator directly to an end-use customer via a dedicated distribution line or distribution grid, rather than being delivered via an open-access power grid. These EFs are appropriate to apply when a reporting entity is connected directly to an electricity generator. Emissions from purchased electricity via a direct line are considered scope 2 emissions and should be accounted for using generator-specific EFs when available.

Grid-Average EFs

The most common type of EF is the **grid-average EF**. This EF is generation-weighted, averaging all GHG emissions (or CO_2 only) associated with all power generation resources in a defined grid region (usually defined by interconnectivity) over a given time period. Typically, these EFs are available on an annual basis (i.e., annual grid-average EF).[35] This type of EF can blur significant seasonal and/or intra-day (peak/off-peak) differences in the emission intensity of system power (i.e., *undifferentiated* electric power taken from the grid). For instance, emissions associated with electricity consumption calculated using a grid average EF likely would be overestimated during periods of high RE generation and underestimated during peak load periods with little or no RE production.

Some Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs)[36] publish GHG intensity data for their operating area. Recently, several ISOs, including the CAISO and PJM, and the US EIA have started to publish data and information on hourly GHG emission rates by balancing areas and grid nodes.[37] The U.S. EPA's eGRID program also publishes emission intensities for grid sub-regions throughout the United States. One challenge to using grid-based EF databases like eGRID is that there often is a long lag time between the current reporting period and the relevant eGRID factor being published. This lag, which could be one or more years, presents challenges as the overall power generation mix has been changing rapidly in certain regions of the country.

[35] Because an entity-level GHG emissions inventory is an *allocational* form of GHG accounting, it relies on the use of grid *average* EFs. However, for "consequential" emissions accounting associated with estimating the potential impacts of GHG emissions reduction interventions, it may be appropriate in some cases to use a "marginal" EF that more closely approximates the GHG EF at the specific time electric power is generated and dispatched onto the grid. Marginal EFs represent the marginal GHG emission source being dispatched on the grid for each hour or sub-hourly time period.

[36] For example, California ISO (CAISO) EFs but only for CO_2 emissions: https://www.caiso.com/todays-outlook/emissions#section-total-co2-trend.

[37] MISO also is in the process of rolling out several emissions data products to help refine the temporal estimation of GHG emission rates later in 2024 and in 2025.

Residual Mix EFs

Residual mix EFs are similar to grid-average EFs, except they exclude the GHG emissions and electricity generation (MWhs) related to RECs, PPAs and similar contractual instruments that are "claimed" by individual retail consumers. Based on the GHG Protocol Scope 2 Guidance, reporting companies that use a market-based accounting approach are required to use a residual mix EF to calculate and report the emissions associated with the remaining undifferentiated "grid" power they consume.[38]

The practice of utilizing contractual instruments and residual mix to avoid double counting involves shifting the allocation of emissions among entities and can misrepresent the physical reality of indirect emissions associated with an entity's electricity consumption. Currently, in the U.S., there are no comprehensive residual mix EFs that factor out all instruments transacted (and hence do not avoid double counting of emissions).[39] In Europe, the Association of Issuing Bodies (AIB) publishes annual residual mix factors for their member countries which factor out the claimed GOs.[40]

Contractual and Other Market Instruments EFs

Contractual and other market Instruments represent environmental attributes that the scope 2 market-based method incorporates to allow entities to apply EFs associated with those attributes (e.g., 0 kg CO_2/MWh) to consumed electricity. The market-based method allows reporting entities to use contractual instruments, such as RECs, GOs, green tariffs, and utility renewable energy programs/products to be a proxy for tracking and allocating generator-specific emissions to an end-user. In reality, RECs, PPAs, GOs are solely records of generation and delivery to a power grid (rather than an end-user). Since contractual EFs do not represent the physical reality of electricity consumed by an end-user, their use does not reflect the real indirect emissions released by consuming electricity, and so are not applicable to be used with the location-based method.

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[38] If a residual mix EF is not available, a reporting company is required to disclose that such an EF does not exist in the region and acknowledge the potential for double counting of voluntary purchases between electricity consumers.

[39] The Green-e® program publishes residual mix factors based on eGRID regions by factoring out all Green-e® voluntary renewable energy sold products: https://www.green-e.org/residual-mix

[40] See https://www.aib-net.org/facts/aib-member-countries-regions.

Utility- or Supplier-Specific EFs

According to the Scope 2 Guidance, utility- or supplier-specific EFs should be calculated based on delivered electricity, incorporating EACs (e.g., RECs) sourced and retired on behalf of customers. For example, if a utility runs a "green power program" where customers sign up to "receive 100% renewable" electricity and the utility purchases and retires RECs for the program, the utility should incorporate these EACs into their utility-specific EFs. These utility- or supplier-specific EFs may relate to a standard product offer (i.e., electricity supplied by the utility including EAC purchases if applicable) or a differentiated product (such as the example utility's green power program), and are required to be disclosed based on the best available information.

While a single utility may be the sole electricity provider for a specific service territory and produce supplier-specific EFs, these EFs are applicable only for market-based accounting under the GHGP. The reason for this is that a utility's service territory typically is connected to a larger regional power grid and could include non-utility generation sources. Because of this, utility- or supplier-specific EFs (i.e., in a pooled grid or non-monopoly situation) do not represent the physical reality of electricity consumed by the end-user and so do not reflect the real indirect emissions released to the atmosphere.

These EFs can be either **source-based** or **load-based** (see below), and this variability should be considered when determining their appropriate use for scope 2 accounting (e.g., scope 2 EFs should not include emission sources upstream of the generation unit(s)).

- **Source-based:** This method estimates the amount of CO_2 (or GHGs) emitted by a specific facility or entity. Source-based based accounting is the most commonly used accounting framework for government regulatory programs that entail legal compliance obligations, such as mandated performance standards or cap-and-trade emission control programs.
- **Load-based:** Load-based accounting incorporates GHG emissions from both an electric utility's owned generation resources and emissions associated with electricity procured via PPAs and from the wholesale power market.[41]

Guidance to calculate utility-specific emissions intensity metrics is provided by The Climate Registry's Electric Power Sector Protocol.[42]

Marginal EFs

A marginal EF represents the emission rate of the marginal electric generating unit (EGU) dispatched to meet real-time electric load. Marginal EFs theoretically are instantaneous and can change continuously as the marginal generating source changes from moment to moment depending on load and grid conditions. Today, marginal EFs are used in consequential GHG

[41] For more information about source- and load-based accounting, see Understanding Source-based and Load-based Greenhouse Gas Emissions Accounting, EPRI, Palo Alto, CA 2022. 3002024037.

[42] The Climate Registry, 2009. Electric Power Sector Protocol for the Voluntary Reporting Program. https://theclimateregistry.org/resources/protocols/ June 2009, version 1.0.

emissions accounting to estimate expected changes in emissions or removals that may be caused by a specific project or program intervention, such as implementing a GHG crediting project. However, marginal EFs are not appropriate to use for allocational accounting, including scope 2 accounting, in part because emissions from marginal EGUs cannot be allocated and could be claimed by multiple companies simultaneously.

Applicability of Scope 2 EFs and Methodological Controversies

The purpose of allocational environmental accounting frameworks is to allocate (i.e., assign responsibility for) aggregate emissions across a population within a defined boundary (e.g., countries or organizations). For instance, a grid-average EF would allocate appropriately the scope 2 emissions associated with electricity consumption to each company consuming electricity from the grid. Direct line, grid average, and national average EFs are used in *physical allocational GHG accounting*, such as corporate GHG emissions inventories.

Residual mix, contractual, and utility- and supplier-specific EFs are used exclusively for market-based accounting. While reporting scope 2 emissions using the market-based approach is permitted under the GHG Protocol, using these EFs does not reflect the physical reality of emissions produced as a result of electricity consumed by a reporting company. As a form of allocational GHG accounting, a corporate or entity-level GHG inventory comprises the physical reality of emissions produced within an organizational boundary; as such, market-based EFs are inconsistent with the very premise of an allocational GHG accounting framework because they reallocate emissions among responsible parties.[43]

Contractual instruments such as RECs or PPAs do not secure exclusive delivery of electricity to the reporting company. As such, experts in the GHG accounting space have long criticized the use of the market-based method in scope 2 reporting[44], as this method essentially permits reporting companies to report scope 2 emissions based on financial transactions and contracts, instead of reporting emissions based on physical activities occurring within their emissions inventory boundary.

[43] See the Green Power FAQ for more information: https://offsetguide.org/wp-content/uploads/2022/05/FAQ-Green-Power-Purchasing-Claims-and-GHG-Accounting_05262022.pdf .

[44] See https://www.sciencedirect.com/science/article/pii/S0301421517306213?via%3Dihub and https://scope2openletter.wordpress.com/.

There is growing concern about the efficacy of using contractually procured RE and purchased RECs to reduce reported corporate scope 2 emissions, and there is now widespread recognition that this approach may lead to inaccurate allocation of GHG emissions. In response to these concerns, the GHG Protocol in 2022 began a comprehensive three-year long effort to review and potentially revise the existing GHG Protocol's Corporate Standard, Scope 2 Guidance, Scope 3 Standard, and Market-based Accounting Approaches.[45] This review is expected to result in publication of revised accounting guidance by the end of 2025.

[45] See https://ghgprotocol.org/ghg-protocol-standards-and-guidance-update-process-0 for information about the GHG Protocol review.

4. BASE YEAR AND HISTORICAL RECALCULATION

Introduction

This brief is the third in a series that accompanies a set of EPRI-sponsored technical webcasts designed to highlight and explore key technical issues and accounting methods associated with corporate greenhouse gas (GHG) emissions accounting and reporting.

This brief explains: (i) Corporate GHG inventory recalculation practices; (ii) The importance of recalculating base year and historic emission inventories; (iii) Events that do and do not trigger recalculations; and (iv) Approaches that can be used to recalculate base year and historic emissions.

Setting a Recalculation Policy

A base year in a GHG emissions inventory is a reference point in the past to which current emissions can be compared. Recalculating base year and historic GHG emission inventories refers to the process of re-estimating a reporting company's historic emissions due to **structural changes** in a corporate entity's organizational or operational boundaries or other "significant" changes.

The GHG Protocol's Corporate Accounting and Reporting Standard[46] requires reporting companies to develop an internal emissions recalculation policy,[47] that includes (i) a reporting company's procedure for performing a recalculation, (ii) an explanation of the types of events that would trigger a recalculation, and (iii) the **significance threshold** the company will use to evaluate changes that may trigger recalculation. The reporting company's internal recalculation policy ensures that if a structural change results in an increase or decrease of emissions within the base year inventory – and if that change meets the reporting company's significance threshold – a recalculation would be triggered.

Significance Thresholds and Structural Changes

A recalculation always will be triggered if structural changes to the reporting boundaries meet the reporting company's significance threshold, or if other changes meet the significance threshold, such as changes in calculation methodology[48] or emission factors (EFs).[49] A

[46] https://ghgprotocol.org/sites/default/files/standards/ghg-protocol-revised.pdf .

[47] Some voluntary reporting programs have additional requirements related to performing a recalculation.

[48] Changes in calculation methodology and the implication those changes have in recalculating a base year inventory are discussed later in this brief.

[49] If an EF used by the reporting company is updated by the relevant authority due to changes in calculation methodology (i.e., to increase the accuracy of the EF), this is also considered a change to evaluate against a reporting company's significance threshold.

significance threshold is a quantitative or qualitative criterion that defines what change is "significant" enough to trigger a recalculation of base year and historic emissions of a reporting company. Under the GHG Protocol, it is the responsibility of the reporting company to define and include this threshold within their recalculation policy.[50]

For example, let us assume Company A's GHG emissions totaled 400 tonnes CO_2e in the base year 2023. When developing their 2024 inventory, Company A discovers an error in the activity data (AD) they used which would result in a decrease of 30 tCO_2e in their base year inventory. Company A's recalculation policy states its significance threshold is 5% of its base year emissions. Because the error in this case resulted in a decrease of more than 5% of their base year emissions, a recalculation of Company A's base year inventory would be triggered. In this case, Company A would recalculate their base year 2023 emissions to be 370 tCO_2e.

A structural change refers to a change that involves the transfer of ownership or control of an emissions-producing facility, activity, or operation from one company to another. **Structural changes include mergers, acquisitions, divestments, and outsourcing or insourcing of activities or operations**.[51] It is important to recognize that a single structural change may not meet a company's significance threshold, and therefore may not trigger a recalculation. However, many minor structural changes may cumulatively reach the threshold triggering a recalculation.

Changes in GHG Accounting Calculation Methods

If a reporting company changes the calculation method(s) used to estimate the GHG emissions associated with a previously reported activity (e.g., shifting from the spend-based approach to the fuel-based approach for a scope 3 category), a recalculation is required if the change meets the reporting company's significance threshold.

If the new calculation method cannot be applied to the base year inventory for some reason (e.g., due to lack of relevant data in the base year), the reporting company can consider if relevant data may be available in the future making recalculation possible, or it may change its base year to a different inventory year for which the relevant data is available.[52] Any changes in EFs or AD that represent differences in physical emissions to the atmosphere do not trigger a recalculation, as these changes will be reflected in the reporting company's GHG Inventory time series.

[50] "Significance" and "materiality" have been common points of confusion in corporate GHG accounting. There is no standard guidance or reference for what should be considered "significant," but many companies use a range between 2-5% when setting a significance threshold. Additionally, some GHG programs establish a significance threshold to be used when reporting corporate emissions under their program. For instance, The Climate Registry (TCR) requires a significance threshold of 5%.

[51] Not all insourcing/outsourcing events will trigger a recalculation. This is discussed later in this brief.

[52] The reporting company also can opt not to recalculate and record this change in methodology without recalculation in their inventory report. It should be apparent to users of the report that, while a recalculation was triggered, it was not performed due to a lack of available and relevant data.

For example, let us assume a reporting company owns three coal-fired power plants. In the 2020 base year, all three plants burned subbituminous coal to generate electricity. In the current inventory year, one power plant started burning lignite instead of subbituminous coal. This change in fuel type does not trigger a recalculation, as the change in fuel type results in a physical change in emissions produced by the reporting company. If the reporting company did recalculate, the change in emissions resulting from the change in fuel type combusted would not be captured in the company's emission profile.

Maintaining time series consistency

Setting a recalculation policy makes it possible for a reporting company to maintain inventory time series consistency. One of the primary reasons to develop an emissions inventory and set a base year inventory is to track a reporting company's emissions over time, with the base year inventory being a point of reference for making inventory time series reduction[53] comparisons. Meaningful comparison between emission inventories only can be achieved with consistent data sets. If the reporting company undergoes a structural change that shifts their inventory boundaries, then a recalculation of the base year and historic inventories needs to be performed so it will be possible to monitor emission outputs and compare inventories over time.

For example, let us assume Company B emitted 2,300 tCO_2e in the base year 2018. In 2019, Company B merges with Company X, thereby acquiring all the Company X's facilities, operations, and other emission-producing activities. This increases Company B's 2019 emissions by 3,000 tCO_2e. This increase triggers a recalculation because Company B's inventory boundaries expanded to include X's facilities and the emissions from those facilities. Because of this ownership change, the emissions from Company X now need to be included in Company B's base year and historic emission inventories to make meaningful comparisons between Company B's inventories throughout their time series.

Changes that Do Not Trigger a Recalculation

The GHG Protocol identifies three types of changes that do not trigger recalculation: (i) Organic growth or decline; (ii) Outsourcing and insourcing; and, (iii) Facilities that did not exist in the base year. Each of these situations is described below.

Organic Growth and Decline

Organic growth and decline refers to any increases or decreases in the reporting company's production output, changes in production mix, and closures and openings of facilities or units within the reporting company's boundary. While a structural change (such as a merger) may trigger a recalculation, organic growth or decline does not. Recalculation to align accounting practices and enable a consistent time series will not lead to a change of emissions to the

[53] The terminology "inventory time series reduction" refers to emission reductions made within the boundary of a company's inventory time series and is what is typically thought of as a corporate "emission reduction."

atmosphere, but recalculating due to organic growth or decline, which do represent changes to atmospheric emission levels, would raise accounting concerns. From a GHG accounting perspective, any changes in emissions that result from organic growth or decline need to be reported and counted as an increase or decrease of emissions within the reporting company's time series.

Recall the previous example in which Company B acquired Company X, which triggered a recalculation of Company B's baseline and historic emissions, as the ownership of existing emissions changed. Let us consider an alternative scenario in which Company B builds and opens eight new facilities, rather than acquiring Company X, which also increases their emissions by 3,000 tCO_2e. This facility expansion does not trigger a recalculation as it is considered organic growth of the company. It does result in a change of the total GHG emissions to the atmosphere, as the eight new facilities did not exist previously. The resulting emissions from these facilities need to be reflected in the reporting company's emissions profile and time series.

Outsourcing and Insourcing

Whether a recalculation is triggered due to *insourcing* or *outsourcing* depends on if the reporting company has single or separate base years[54] or GHG emissions targets[55] for individual scopes or total GHG emissions, and if the reporting company previously reported the insourced or outsourced activity. Table 4-1 illustrates how these criteria are applied in determining whether a recalculation is triggered.

As shown in Table 4-1, a recalculation is <u>not</u> triggered if the reporting company previously reported emissions from the activity being insourced or outsourced and if the company has a single base year for its total scope 1, 2, and 3 emissions (i.e., the company uses a single base year for tracking total inventory time series reductions as opposed to tracking inventory time series reductions separately between scopes, where each scope may have a different base year).

[54] A reporting company can choose to define separate base years for different scopes and/or for specific scope 3 categories. Doing so may be useful depending on data availability across different emission scopes and scope 3 categories, and/or the reporting company has different GHG targets for different scopes and/or scope 3 categories.

[55] A GHG target is an inventory time series reduction goal set by a reporting company. A GHG target can be either absolute (reducing absolute emissions over time) or intensity based (reducing a ratio of emissions relative to a business metric over time). In cases, progress toward meeting the GHG target is measured using a target base year. Setting GHG targets is not discussed further in this brief.

Table 4-7: Determining when insourcing/outsourcing triggers a baseline recalculation

Company Base Year and GHG Emission Target	Company previously reported emissions for insourced or outsourced activity	Company did not previously report emissions for the insourced or outsourced activity
The company has a single base year or GHG target for total scope 1+2+3 emissions	No recalculation	Recalculation is triggered (if it meets significance threshold)
The company has separate base years or GHG targets for individual scopes (or individual scope 3 categories)	Recalculation is triggered (if it meets significance threshold)	Recalculation is triggered (if it meets significance threshold)

For example, if the reporting company self-generated electricity for their own consumption in their base year (i.e., a scope 1 emissions source), and instead opted in the current year to purchase all of the electricity to meet their <u>own consumption</u> from a third-party (i.e., a scope 2 emissions source), a recalculation is <u>not</u> triggered because both scope 1 and scope 2 are required to be reported in a corporate inventory and this change represents a shift of scope 1 emissions to scope 2.

However, a recalculation would be triggered if the reporting company <u>did not</u> previously report emissions from the insourced or outsourced activity, or if the reporting company has separate base years or GHG targets for individual scopes or individual scope 3 categories.

For example, let us assume the reporting company is an electric utility that owns several power plants, and the electricity generated by those power plants was delivered to end-users in the 2020 base year inventory and reported as a scope 1 emissions source. In the current year inventory (e.g., 2024), however, the reporting company sold one of the power plants to another utility, and to make up for the "lost" generation from the sold plant chose to purchase electricity from the grid which was resold to end-users. In this case, the emissions associated with the purchased electricity to be resold to end-users would be accounted for as a scope 3 emission source, specifically category 3: fuel and energy related activities. In this case, a recalculation would be triggered if the reporting company did not previously report scope 3, category 3 emissions. If the reporting company <u>did</u> previously report scope 3 category 3 emissions, but they have separate base years or GHG targets for each emission scope (e.g., the scope 1 base year is 2020 and the scope 3 base year is 2021) and/or scope 3 category, then a recalculation also would be triggered.

Changes Involving Facilities that Did Not Exist in the Base Year

In the event a structural change involves a facility or activity that <u>did not exist</u> in the reporting company's base year, a recalculation of the company's base year is <u>not</u> triggered. This is because, when a reporting company compiles a corporate emissions inventory, it only account for emissions that physically occur; it is not possible to recalculate a base year to include emissions that did not exist. However, the GHG Protocol instructs reporting companies to recalculate their historic inventories to the year the acquired or insourced facility, activity, or operation came into existence (i.e., when the facility, activity, or operation started to produce emissions). This same approach is applied for corporate divestments and outsourced activities.

For example, if Company A divests Company Y, a recalculation of Company A's base year and historic inventories would be triggered to account for this divestment. However, since Company Y did not exist in Company A's base year, a recalculation of Company A's base year is not possible (i.e., you cannot account for emissions that did not exist). This structural change does trigger Company A to recalculate its historic inventories up until the year Company Y came into existence. For instance, if Company Y started to operate in 2018 and was sold by Company A in 2024, then Company A would recalculate its GHG inventories for the years 2023, 2022, 2021, 2020, 2019, and 2018 to remove Company Y from its inventories.

Approaches to Recalculating an Emission Inventory

There are two standard approaches to performing a recalculation: the **all-year** and **pro-rata** approaches. These approaches are applicable to both a fixed base year and a rolling base year[56] inventory method; however, because a rolling base year is uncommon, the examples used to illustrate these approaches focus on the fixed base year method.

All-Year Approach

Recalculation under the all-year approach does not pro-rate any emissions data (in contrast to the pro-rata approach discussed below). Instead, using this approach the full change in emissions is applied to the current inventory year, the base year, and historic inventories, even if the change occurred part way through the reporting year.

For example, assume Company B acquired Company X on June 30, 2019, and Company B chooses to recalculate their emissions using the all-year approach. As shown in Table 4-2, Company X's base year emissions were 1,000 tCO_2e, and their 2019 emissions were 3,000 tCO_2e. Using the all-year approach, Company B recalculates their 2018 base year inventory to include the full 1,000 tCO_2e of Company X's emissions, and Company B includes the full 3,000 tCO_2e of emissions from Company X in their 2019 inventory.

Table 4-2. Example of Applying the All-year Recalculation Approach to Recalculating Base Year and Historic Emissions.

Company & Merger Status	2018 Emissions (Base Year)	2019 Emissions
Company X	1,000 CO_2e	3,000 CO_2e
Company B	2,300 CO_2e	2,300 CO_2e
Company B – **post-merger,** (recalculated emissions in **2019)**	3,300 CO_2e	5,300 CO_2e

[56] A rolling base year is a base year setting approach where the GHG inventory base year "rolls over" at regular pre-determined intervals, usually one year.

The all-year approach is by far the most common method used to recalculate base year and historic inventories, and often it is a better approach for most reporting companies as it is less complicated than using the pro-rata approach. Using the all-year approach, the reporting company only needs to recalculate their base year and historic inventories once, to reflect the change in emissions for the full year, instead of pro-rating the emissions to reflect a partial-year change.

Pro-Rata Approach

An alternative to the all-year approach to recalculating base year and historic emissions is to use the *pro-rata approach* discussed below. Using the pro-rata approach, if the structural change occurred part-way through the reporting year, the recalculation would be performed across both the partial reporting year and the subsequent complete reporting year. During the partial reporting year, the reporting company would pro-rate the emissions associated with the structural change for that year and recalculate the base year to reflect the same pro-rated change in emissions. Then, in the subsequent full reporting year, the company would recalculate the base year again without pro-rating to account for the full year of emissions resulting from the change.

The pro-rata approach requires reporting companies to recalculate their base year and historic emission inventories twice, and it is a more complicated to implement than the all-year approach.[57] Use of the pro-rata approach is uncommon, and it is not usually recommended. However, it may be useful in the event that the reporting company seeks to illustrate two different operational structures within one inventory. The steps to implementing the pro-rata approach are described below and shown in Table 3 using the previous the example of Company B acquiring Company X.

Recall from the example shown in Table 2, that Company B acquired Company X on June 30, 2019. Table 4-3 shows the companies emissions and how recalculation-post merger impacts both 2018 and 2019 emissions inventories based on the pro-rata approach.

[57] One reason the pro-rata approach is more complicated is that it requires the reporting company to collect partial AD (to reflect a partial year's worth of emissions) instead of applying the full year of emissions to the base year recalculation.

Table 4-3. Example of Applying the Pro-rata Approach to Recalculating Historic Emissions

Company and Merger Status	2018 Emissions (Base Year)	2019 Emissions
Company X	1,000 tCO_2e	3,000 tCO_2e
Company B	2,300 tCO_2e	2,300 tCO_2e
Company B – post-merger (Recalculated emissions in **2019**)	2,800 tCO_2e	3,800 tCO_2e
Company B – post-merger (Recalculated emissions in **2020)**	3,300 tCO_2e	5,300 tCO_2e

Using the pro-rata approach, Company B would recalculate their base year inventory for 2018 to include half of Company X's 2018 emissions (1,000/2 = 500 tonnes CO_2e) to reflect that Company X was acquired halfway through the year. Company B's base year recalculation results in 500 additional tonnes CO_2e, for a total of 2,800 tonnes CO_2e.

During the 2019 inventory year, Company B would pro-rate Company X's 2019 emissions in the same way (3,000/2 = 1,500 tCO_2e), which brings Company B's 2019 emissions to 3,800 tCO_2e.

In the 2020 inventory year, Company X has been merged into Company B for the entire year, which means Company B must recalculate their 2018 base year and 2019 historic inventory again, this time to include Company X's emissions from the entire year. This means Company B recalculates their 2018 base year inventory to include the full 1,000 tonnes CO_2e from Company X, making B's total 2018 emissions 3,300 tCO_2e, and recalculates their 2019 inventory to include the full 3,000 tCO_2e from Company X, making B's total 2019 emissions 5,300 tCO_2e.

Implications of Recalculating Base Year and Historic Emissions

The recalculation of base year and/or historic emission inventories may have important implications for reporting companies.

First, recalculating base year and historic emissions could potentially mean that the "new" recalculated emission inventories will be substantively different than the values a reporting company would have previously reported without recalculation. This will require a reporting company to explain these changes in its inventory report and in its corporate communications (e.g., corporate annual sustainability report).

Second, it may require the company to reframe its previously announced corporate GHG inventory time series reduction targets, particularly if these were absolute GHG targets (e.g., a reduction of 30% of total emissions (scopes 1, 2, and 3) relative to the 2022 base year by 2027). For example, if a reporting company recalculates their base year inventory and as a result their base year emissions increase, then their previously communicated GHG target may not be achievable or may require new strategies to fulfill. In such cases, the GHG target relevant to the base year may also need to be revised.

Third, base year and historic recalculation can reduce the potential for reporting companies to be criticized for “green washing,” as the recalculation would demonstrate that the reporting company is not attempting to inappropriately take credit for inventory time series reductions that were not actually achieved, but rather they’re maintaining time series consistency and any physical inventory time series reductions are evident in their emissions profile.

5. INSETTING: CLAIMING AVOIDED GHG EMISSIONS OR ENHANCED REMOVALS ASSOCIATED WITH VALUE CHAIN INTERVENTIONS

This technical brief is the fourth in a series that accompanies a set of EPRI-sponsored technical webcasts designed to highlight and explore key technical issues and accounting methods associated with corporate greenhouse gas (GHG) emissions accounting and reporting**.**

This brief focuses on the concept of GHG emissions "insetting," and addresses the following topics:

1. Explains how insetting may be used to quantify avoided GHG emissions or enhanced removals associated with scope 3 value chain interventions;
2. Discusses how some parties have proposed integrating insetting into existing GHG accounting guidance;
3. Illustrates insetting using an example from a company doing it; and,
4. Identifies challenges to insetting, and the potential risks to companies pursuing insetting interventions.

What is Insetting?

A GHG emissions inventory is a quantification of the GHG emissions and removals allocated to a company's operations over a defined period, typically a calendar or fiscal year. Many companies seek to decrease the GHG emissions in their inventory by mitigating their direct and indirect emissions. **Insetting is a controversial and emerging approach that has been proposed to allow companies to report lower scope 3 value chain emissions by supporting the implementation of project "interventions."**

It is important to recognize that insetting does not necessarily physically lower an entity's scope 3 emissions, but rather this approach seeks to allow companies *to report* lower scope 3 emissions. Also, insetting does not necessarily require a reporting company to be the entity directly implementing an insetting intervention; they may rely on a third party or community partner or provide financial support to those entities implementing an insetting intervention.

Scope 3 "value chain" emissions are included in corporate GHG inventories based on the GHG Protocol's *Corporate Value Chain (Scope 3) Standard*[58] (henceforth referred to as the "Scope 3 Guidance"), which defines 15 broad categories of "upstream" and "downstream" activities.[59] Generally, scope 3 value chain emissions are challenging for companies to reduce because they

[58] https://ghgprotocol.org/sites/default/files/standards/Corporate-Value-Chain-Accounting-Reporing-Standard_041613_2.pdf

[59] For more information about upstream and downstream scope 3 GHG emissions accounting see EPRI publication related to Scope 3 emissions accounting.

do not have direct control over the activities that cause these emissions and are often limited in their ability to impact value chain partners' decision-making. Scope 3 emissions typically are optional to report for most reporting programs, but when reported, they are often larger than a company's scope 1 and/or scope 2 emissions.[60]

Guidance on insetting initially was developed by companies with agricultural supply chains[61] and "…is primarily aimed at interventions that affect purchased goods and services."[62] The Gold Standard's (GS) Insetting Guidance also identifies the potential to extend insetting beyond the scope 3 category 1: purchased goods and services emission sources. Beyond category 1, insetting approaches could be considered for other scope 3 emission sources in categories that may be of direct interest to electric companies, including: upstream fuel extraction and processing (category 3), power purchased for resale (category 3), and for downstream use of sold products (category 11).[63] However, given the lack of substantive guidance about appropriate methods to implement an insetting approach, there could be significant risks to companies that seek to execute insetting activities in the near term. Specifically, companies implementing insetting activities can expect to be challenged by interested stakeholders and media institutions about the credibility of insetting claims and the determination of the GHG emissions impact associated with any insetting interventions.

For companies that wish to use an insetting approach, the "*Gold Standard Value Chain (Scope 3) Interventions Greenhouse Gas Accounting & Reporting Guidance*[64]" (henceforth referred to as the GS Interventions Guidance) provides guidance related to the following elements:

1. Accounting for the net emission changes associated with a given value chain intervention;
2. Credible accounting in the company's scope 3 inventory and reporting, where appropriate; and,
3. Making narrative claims that describe the company's role in the Intervention and the impacts arising from it.

Insetting is a controversial approach that has not been widely accepted by GHG accounting experts and is still evolving conceptually and methodologically. Insetting is similar to offsetting (i.e., the use of carbon credits to offset emissions), but currently lacks the same high-level programmatic and technical requirements that must be fulfilled when implementing a carbon

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[60] Note, there are conceptual problems with comparing scope 3 with scopes 1 and 2. See https://ghginstitute.org/2024/04/02/myth-busting-are-corporate-scope-3-emissions-far-greater-than-scopes-1-or-2/

[61]Brandt S., et al., 2022. A Practical Guide to Insetting. International Platform for Insetting. March 2022. https://www.insettingplatform.com/insetting-guide/

[62] Gold Standard, 2021. Value Chain (Scope 3) Interventions – Greenhouse Gas Accounting & Reporting Guidance. https://www.goldstandard.org/publications/scope-3-value-chain-interventions-guidance .

[63] The Gold Standard Intervention Guidance identifies that additional work may be required to apply the existing insetting guidance beyond scope 3 category 1 emission sources.

[64] Ibid., Gold Standard, 2022.

crediting project in line with a program-approved methodology and following the auditing and other crediting program requirements to produce carbon credits. For this reason, **carbon credits**, which can be used to offset emissions, are distinct from **insetting intervention units**, which do not currently achieve the same standard of technical rigor and involve more substantial environmental integrity risks if used to offset emissions.[65] The challenges associated with insetting are described in more detail later in this brief.

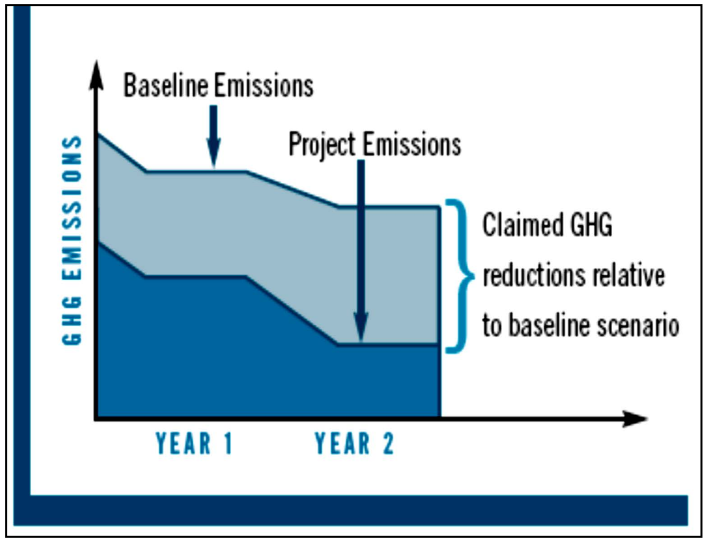

Figure 5-1: Quantifying GHG Reductions from Projects

Source: Adapted from *The Greenhouse Gas Protocol: Guidelines for Quantifying GHG Reductions from Grid-Connected Electricity Projects*, World Resources Institute (WRI) and World Business Council for Sustainable Development (WBSCD), 2007.

Consequential GHG Emissions Accounting

There are two types of GHG emissions accounting which are used for different purposes. *Consequential* methods are used to estimate the GHG emissions impact of policy changes, carbon crediting projects, and other actions or interventions designed to avoid GHG emissions or enhance GHG removals. Consequential accounting is distinct from allocational GHG accounting (aka attributional accounting)[66] which seeks to allocate responsibility for GHG emissions from specific activities to specific entities. Corporate GHG accounting is a type of allocational GHG accounting that includes emissions from the three different GHG emissions "scopes."

Consequential accounting provides the foundation for carbon crediting programs like the Climate Action Reserve (CAR) and the Verified Carbon Standard (VCS) For crediting projects, "baseline emissions" (i.e., the scenario in which the policy change, project, action, or intervention did not occur) are the reference against which avoided emissions or enhanced removals are calculated. Conceptually, baseline emissions represent what would have occurred in the absence of demand for carbon credits. Baseline emissions are estimated by predicting the emissions that would have occurred in the absence of the incentive created by demand for carbon credits (e.g., in the absence of the project).

[65] Note that carbon credits are also prone to environmental integrity risks as evidenced by the numerous reports exposing fraudulent or overestimated crediting projects over the past few years. The structures provided by crediting programs provide some reduction of environmental integrity risks for carbon credits, which does not exist for insetting intervention units.

[66] Previously, "allocational" GHG accounting was referred to as "attributional" GHG accounting. Today, GHG accounting experts are transitioning to use the term "allocational" to describe this type of GHG accounting.

A crediting project's quantified avoided emissions is the difference between the *actual* emissions that occur after a crediting project is implemented and its predicted baseline emissions over that same time as shown in Figure 5-1.

Insetting has been conceptualized in part based on project-level consequential GHG accounting that has been used for many years to quantify the carbon credits generated by projects which are primarily used by credit buyers to offset emissions. While this fundamental approach to determining an intervention's impact is similar to carbon crediting (e.g., for offsetting purposes), **insetting typically does not require interventions to meet the same environmental integrity quality criteria as carbon credits** that help ensure the comparison of baseline to intervention scenarios are conservatively quantified, and that the project scenario would not have occurred in the absence of the project developer's actions (e.g., additionality).

Quantifying Avoided Emissions and Enhanced Removals from Insetting Interventions

There are three basic steps involved in conceptualizing and quantifying avoided GHG emissions and/or enhanced removals associated with insetting interventions:[67]

1. Select and define the intervention;
2. Define the intervention's baseline scenario and quantify its avoided GHG emissions impact; and,
3. Monitor, report, and verify (MRV) the intervention's avoided emissions and/or enhanced removals.

The basic formula used to estimate GHG emissions associated with an activity is shown in Equation 2.

$$\text{Activity emissions} = \text{Quantity (of activity) x EF (for one unit of that activity)}$$

Equation 2. Basic formula to quantify activity emissions

If a company is choosing between alternative products to consume, it may wish to estimate the avoided emissions from switching to a less GHG emissions-intensive product. A company may choose to make an intervention to lower the GHG intensity of a product it purchases compared to the most likely baseline scenario (e.g., historical or common practice). Assuming the same quantity of a product would be purchased in both the baseline and the intervention scenarios, a simplified method to estimate the avoided GHG emissions from this intervention would be to subtract the intervention product's average production EF from the baseline scenario product's average production EF and then multiply that difference by the quantity consumed, as shown in

[67] Ibid., Gold Standard, 2022.

Equation 3. However, this simplified approach is problematic from a GHG emissions accounting standpoint and may overestimate potential avoided emissions.[68]

$$\text{Avoided Emissions} = (\text{AVG EF}_{\text{baseline}} - \text{AVG EF}_{\text{intervention}}) \text{ x Quantity}_{\text{activity}}$$

Equation 3. Simplified method to estimate avoided GHG emissions from an intervention

The GS recommends each of the steps be independently audited, and for quantified intervention impacts to be certified by an insetting crediting program like the GS, the evolving Advanced Indirect Mitigation (AIM) Platform, or Verra's Scope 3 Standard Program.

Step 1: Define the Intervention

In this context, an intervention is a specified action that occurs within a company's value chain or *may occur* within the company's value chain if value chain uncertainty exists. Ideally, insetting targets a specific GHG emitting process in a reporting entity's upstream supply chain (e.g., transportation of fuel to a natural gas plant). However, a company often cannot directly trace a purchased commodity through its upstream value chain to a specific supplier. In this case, the company might define the intervention to impact entities that are likely to be connected to their value chain. The term "supply shed" is used to refer to a broad group of suppliers from which the company may be receiving products when the direct connection to a supplier cannot be established or there is uncertainty in an entity's known value chain.

In many cases, a physical connection to a supplier (e.g., a crop producer) may not be possible to track because commodities are purchased after being aggregated or transferred between intermediaries and by definition are standardized and fungible. When the specific supplier cannot be identified and no physical connection to the supply chain can be made, but the goods and services can be shown to originate from a representative area, region, or sector, it is considered to be good practice to choose the most accurate and granular EF available and then target the intervention to sites within this representative supply shed designation (i.e., within the area, region, or sector).[69]

For example, if a reporting company purchased 10 tonnes of cotton annually from unknown suppliers in a region, the company could target interventions on farms in the region that together produce 10 tonnes of cotton on average per year. By making interventions, the company would seek to lower the carbon intensity of cotton production, and by applying insetting, the company would seek to claim the improved cotton production EF to determine the emissions of the 10 tonnes of cotton they procure from the supplier group. Then, the

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[68] The simplified method shown in Equation 2 runs counter to best practice in GHG accounting for interventions because it uses average production EFs rather than marginal production EFs. Typically, marginal production EFs are used to evaluate production-related interventions. The use of average EFs may add significant uncertainty to quantifying avoided GHG emissions associated with value chain interventions.

[69] Ostianova, N., et al, 2024. Emerging landscape of voluntary insetting and scope 3 standards [webinar recording]. International Platform for Insetting. October 9th, 2024.

reporting company would compare the intervention cotton production EF against the baseline cotton production EF to determine the impact of the interventions.

Interventions also may target a value-chain partner's full operations (and all product lines), but the insetting company may only purchase one type of good from that supplier. For example, farms often produce multiple crops and factories produce multiple goods, but the reporting company may not purchase all types of products from their value chain partner(s). In this scenario, the impact of an intervention might lower the emissions of all produced goods not just those purchased by the insetting company. The GS Interventions Guidance recommends that companies "…should apply an allocation adjustment" in these situations, reducing the quantified intervention's emissions impact from the total impact on all products to the proportional impact assigned to the single purchased good.[70,71]

To appropriately account for the GHG emissions impact of interventions, a few assumptions are required to be made. First, the intervention must not result in emission leakage effects or these must be appropriately incorporated into the intervention's quantification; and, second, the *average* emissions rate for the production of a unit of the purchased good approximates the *marginal* emissions *rate* for the production of a unit of the purchased good. Typically, marginal emissions rates differ from average emissions rates, so using average emission rates, while simplifying intervention quantification, may add a high degree of uncertainty to the calculation.

Insetting interventions typically are quantified by developing an EF that represents the emissions released by the production of one product or the provision of one unit of a service as shown in Equation 4. The guidance identifies the use of average production EFs for this purpose. However, consequential GHG accounting properly would apply a **marginal production EF**. The insetting approach, and the use of average production EFs, will only provide an approximate estimate of the GHG emissions that may be avoided by an intervention.

$$\text{AVG EF}_{\text{intervention}} = \frac{\text{Total emissions from the production of products after the intervention}}{\text{Quantity of goods or services}}$$

Equation 4. Developing the intervention production EF

If the company purchases a greater volume of goods than the total impacted by the intervention, the intervention-EF is expected to be applied only to the total quantity of impacted goods.

[70] Ibid. Gold Standard, 2022.

[71] Note, that there is not a consensus that this approach to insetting is credible or correct. See https://ghginstitute.org/2024/01/31/what-is-ghg-accounting-market-based-mistake/

Step 2: Define the Insetting Intervention Baseline Scenario and Quantify the Emissions Impact

The baseline scenario is defined by an EF that represents the emissions from goods and services (or emission sources more broadly) that would occur without the intervention. Equation 5 can be used to calculate the Baseline EF provided the baseline scenario is determined to be the prior practice.[72]

$$\text{AVG EF}_{\text{baseline}} = \frac{\text{Total emissions from the production of products prior to the intervention}}{\text{Quantity of goods or services produced}}$$

Equation 5. Developing the baseline production EF

The same uncertainty exists for quantifying the baseline scenario emissions as for the intervention emissions relating to the use of average instead of marginal EFs. The EF used to quantify the intervention and baseline scenario emissions should have the same boundaries, and quantification of both scenarios' emissions should be undertaken by applying comparable methods. If any significant changes occur after the development of an EF – but still prior to the intervention (thereby impacting the accuracy of the baseline EF's use into the future) – a "conservative accommodation" should be incorporated to adjust the EF.[73]

Some baseline scenario and intervention EFs used for insetting are akin to life cycle assessment (LCA) EFs. Consequently, the extent of their boundaries (i.e., how far up, or downstream from production one includes emission sources) is one of the critical factors that must be consistent between the project and baseline scenario EFs. The EFs may be developed or adapted from existing project-level crediting methodologies developed by crediting programs like ACR (formerly the American Carbon Registry), CAR, the Clean Development (CDM), GS, and Verra's Verified Carbon Standard (VCS). **Guidance to transition a project-level methodology's quantification approach to be used for insetting is still under development**. The quantification sections of project methodologies potentially could be adapted to insetting because a project-level methodology seeks to identify the causal impact and differences between a project and baseline scenario. An EF for insetting would not need to incorporate the full LCA of a product or service through the product's lifecycle, but rather – akin to project-level accounting – only those emission sources that change from the baseline to the project scenario as a result of the intervention.

[72] The GS Interventions Guidance implies the baseline EF should reflect prior practices, but this should be evaluated further as the baseline scenario for a given intervention may be informed by prior practices, may change as technology improves, or practices may shift to reflect industry trends.

[73] Ibid. Gold Standard, 2022.

Additionally, an insetting methodology also would need to incorporate any leakage effects that may result from an insetting intervention. Market leakage and activity shifting leakage are the two most common types of leakage[74] and would need to be incorporated if they occur:

- *Market leakage* occurs if the intervention causes a change in demand or cost of the product, or a competitor's product.
- *Activity shifting* leakage occurs if the intervention improves practices or technology at the targeted sites but shifts the previously existing, and more GHG-intensive practices, elsewhere.

Provided that the baseline and intervention EFs have the same boundaries (or conservative accommodations have been made to account for any differences) the intervention's avoided emissions impact can be quantified as shown in Equation 6:

$$\begin{aligned}\text{Intervention impact} &= (Baseline\ EF\ \times\ Baseline\ quantity\ of\ goods\ or\ services) \\ &\quad - (Intervention\ EF\ \times\ Intervention\ quantity\ of\ goods\ or\ services)\end{aligned}$$

Equation 6. Quantifying the intervention's impact

It is important to remember that the intervention quantity of goods or services cannot exceed the amount of goods or services that the intervention affected (e.g., if an intervention improves the efficiency of one production line only the goods produced from that production line may apply the intervention EF, rather than the entire factory's output).

Step 3: Monitoring, Reporting, and Verification for an Intervention

According to the GS, the MRV following implementation of the value chain intervention should ensure annual production quantities and/or service provision levels are tracked and the emission rates embodied in the intervention EF continue to be accurate. The GS Interventions Guidance suggests companies attempting to apply insetting approaches maintain a record of directly traceable goods and services (i.e., those for which the origin is known) separate from untraceable goods and services (i.e., those which are in the supply shed, but the origin is not known).[75] Although requirements do not exist within the GS Intervention Guidance, the GS recommends monitoring frequency of 1-5 years and reporting aligned with annual GHG inventory reporting for a period of 5-20 years.[76]

MRV for intervention accounting could conceptually be similar to the requirements for crediting project GHG accounting as required today for approved carbon crediting program methodologies. For example, an intervention project targeting improved forest management (IFM) to decrease a company's scope 3 emissions associated with the use of wood products

[74] For more information about carbon credit accounting and leakage, see Exploring the Role of Greenhouse Gas Emissions Offsets to Achieve Corporate Decarbonization Goals: A Compendium of Technical Briefing Papers and Frequently Asked Questions. EPRI, Palo Alto, CA: 2022. 3002025723.

[75] Ibid. Gold Standard, 2022.

[76] Ibid. Gold Standard, 2022.

could follow the MRV requirements identified in an existing approved IFM carbon crediting methodology.

Accounting for and Reporting Insetting Interventions

When accounting for the emissions impact of an insetting intervention, the GS instructs companies to disclose the level of connection (e.g., directly connected, within the supply shed) to their value chain and corporate inventory boundaries. For each intervention, a company is supposed to be able to demonstrate that the intervention is what caused the change in emissions between the baseline and intervention scenarios, and that this change in emissions would not have occurred in the baseline scenario. This is a less rigorous version of the existing additionality requirements for carbon crediting projects. If companies pursue insetting, they can reduce the risks of environmental integrity concerns by mimicking the requirements for carbon crediting projects and increasing the documentation used to support interventions – particularly with regard to the fulfillment of credit quality criteria (e.g., additionality, conservative quantification, permanence).[77] **Carbon crediting programs like GS and Verra currently are working to transition approved carbon crediting methodologies to function for insetting purposes, which will provide greater specificity regarding the methods to fulfill the accounting guidelines specified in the GS Interventions Guidance.**[78]

Communicating Insetting Intervention and Claims

Once an insetting project has been implemented and the avoided emissions quantified, the insetting company must choose how to report the impact of their interventions. Several options for doing this are suggested in the GS Interventions Guidance. These are presented below along with the caveats that (i) making emissions-related claims associated with insetting involves significant environmental integrity risks that could result in negative media coverage and stakeholder concerns, and (ii) existing approaches being used for insetting today may change in the future.[79]

Claims of Insetting Impact Akin to Carbon Credits

One approach suggested by the GS guidance is to count the intervention's impact as carbon credits. For example, the Verra Scope 3 Standard Program (S3S), calls these credits Scope 3 Intervention Units.[80] Credits can be reported alongside a corporate GHG inventory to support a claim that an insetting intervention has helped a company achieve progress toward lowering its emissions. This claim can be specific to a targeted emission source or scope of emissions if a

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[77] For more information about these issues and offset credit quality, see EPRI 2022.

[78] Ostianova, N., et al, 2024. Emerging landscape of voluntary insetting and scope 3 standards [webinar recording]. International Platform for Insetting. October 9th, 2024.

[79] Ibid. Gold Standard, 2022.

[80] Verra's S3S program is still in development. In 2025, Verra plans for a 2nd public consultation, to finalize guidance, and launch version 1.0 of the program.

company wants to equate the intervention activity directly to the emission source that the intervention impacts. **While insetting intervention units may be claimed by companies in a manner similar to carbon credits, it is important to recognize these units are not as rigorously quantified and have not undergone 20+ years of scrutiny as has been the case with carbon credits**. Therefore, the use of intervention units to offset emissions may face warranted scrutiny and skepticism from external stakeholders. **The authors of this technical brief want to emphasize that this approach is not recommended currently as it may present significant environmental integrity and reputational risks.**

Claims of Financial Impact

The GS Interventions Guidance also states that companies can claim their role in financially enabling an insetting intervention by describing their actions and the impact of the intervention, yet not make changes to their GHG inventory reporting or report progress toward achieving their emission reduction targets (except perhaps as memo items). For example, if a company's intervention overlaps with the Nationally Determined Contribution (NDC) of the country it operates in, a domestic policy, or another initiative that the company wants to align itself with, then the company can identify in its reporting how its intervention contributes to achieving this broader policy objective or initiative.

This type of claim does not represent the same risks as claiming insetting intervention units to offset emissions. However, the quantification of an intervention's impact may still be scrutinized, and it is recommended that companies making these claims ensure their interventions fulfill credit quality criteria to reduce reputational risks.

Produce Marketing Material Only

Similar to the reporting option described above, if a company's intervention lowers the production emissions of goods or services produced by a supplier, or causes emissions to be lowered in products purchased beyond the insetting company's purchased quantity (or product lines), the company may make a narrative claim related to the impact within and/or beyond its value chain. The company could detail the extent of the emissions avoided by the intervention and communicate this impact to its stakeholders without decreasing its GHG emissions inventory or using intervention units to offset emissions.

If a company chooses this approach, it is recommended that the company not make any claim relating to its emissions inventory or carbon credit-related claims from the intervention's impact. While this will reduce the reputational risk, the quantification of an intervention's impact may still be scrutinized, and it is recommended that companies making these claims ensure their interventions fulfill credit quality criteria to reduce reputational risks.

Impact on Reported Scope 3 GHG Emissions

One possible interpretation based on the GS guidance is that a company sponsoring an insetting intervention may count the avoided emissions or enhanced removals impact of the intervention as a decrease in the affected scope 3 emission sources within the company's emissions inventory. Many companies do this, but it is technically incorrect and risky. It is incorrect because a GHG inventory must identify all emissions that are occurring within its defined boundaries. Interventions that affect untraceable supply shed goods and services may not be in the company's physical GHG inventory, and therefore such interventions should not be claimed to lower companies' scope 3 inventory estimates (as they may fall outside the inventory boundaries). Traceable goods and services should be reflected in a GHG inventory if their supplier-specific data is accessible. If a company includes emission sources from an untraceable supply shed good or service that is not physically connected to the company, it will contradict good practice in GHG inventory accounting if it reports lower scope 3 emissions. In this case, the intervention's impact would lower reported scope 3 inventory emissions, but the actual source of the company's emissions in its boundary would still be physically emitted to the atmosphere and not be captured by the inventory.

This practice is also considered risky as it is essentially claiming an intervention's impact to offset emissions without rigorous environmental integrity checks or requirements (see section "Claims of Insetting Impact Akin to Carbon Credits").

Does Insetting Align with Scope 3 Inventory Accounting?

Insetting is intended to supplement existing Scope 3 Guidance. The GS Interventions Guidance distinguishes a scope 3 *inventory reduction*, such as a supplier adopting new technologies that will lower its inventoried emissions, from an *insetting intervention* in which a company can substantiate a causal claim for the intervention's impact. The GS Interventions Guidance also identifies that a goal of insetting is to enhance the granularity and improve the data sources that inform companies' value chains and scope 3 accounting. Insetting is conceptualized through this guidance as an intermediate step, allowing companies to take meaningful actions within their supply shed until they can trace their value chain more precisely, and for example, identify individual suppliers responsible for scope 3 emissions who can then be accurately represented in a company's emissions inventory by using supplier-specific data.

Insetting interventions can help companies report lower scope 3 emissions if calculation methodologies and data used to estimate the emissions inventory are sensitive enough to detect changes resulting from the intervention. This still requires the quantification of the intervention's impact to remain distinct from the scope 3 inventory estimation. For instance, if a company uses a regional average production EF to calculate a scope 3 emission source, an intervention targeting that source is unlikely to affect the emissions estimate, as the regional EF is too broad to reflect the impact of a single intervention. However, if the company collects supplier-specific data to quantify the scope 3 emissions source, an intervention may result in a measurable change in the inventory estimate. While this approach is valid, it depends on the company avoiding double-counting the intervention's impact—such as by claiming as carbon credits.

The GS Interventions Guidance recommends that companies <u>do not</u> seek carbon credits from activities that are included in their scope 3 GHG inventory as this would constitute double claiming.[81] It is assumed that this guidance on carbon credits includes insetting intervention units that may be used as carbon credits.

Case Study: Nestlé

Nestlé, one of the largest multinational food & beverage conglomerates, has implemented various large-scale and long-term reforestation and agroforestry projects across its agricultural suppliers, and within other known supplier groups in relevant geographical regions, to produce less emissions and sequester more carbon. The company's largest emission source from its value chain comes from the production of the product ingredients it sources. The projects it implements reportedly are designed to impact farms that produce these ingredients. Nestlé has published its framework detailing the implementation principles each project must comply with.[82] The principles include additionality, permanence, legal and carbon rights, eligibility, real and measurable, no double counting, stakeholder consultation and consent, no harm, and additional co-benefits.[83] Nestlé has set emission targets and identified actions in and around farms where they source their key ingredients.

The company implements projects across the following self-classified levels of connection (or "zones"):[84]

1. **On-Farm**: Projects implemented on farms that are known suppliers (direct or indirect) of an ingredient or raw material procured by Nestlé.
2. **Supply shed farm (commodity-specific):** Projects implemented on farms that are part of a group of suppliers in a specifically defined geography (e.g., part of an agricultural cooperative) that Nestlé sources an ingredient or multiple ingredients from, directly or indirectly.
3. **Supply shed farm (non-commodity specific):** Projects implemented on neighboring farms that are closely connected (environmentally and/or socioeconomically) to farms from which Nestlé sources an ingredient or multiple ingredients; however, this specific farm does not grow the ingredient(s) Nestlé sources.

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[81] The double claiming referenced could occur if an entity claimed the emissions that have been lowered through an insetting intervention to make progress toward a GHG inventory target, while also selling carbon credits quantified from the targeted intervention to a third-party buyer who claims the same avoided emissions toward their GHG emissions target. It is also possible that carbon credits are purchased by a third-party buyer who does not make a claim related to the avoided emissions (e.g., buyers who might purchase credits and contribute them toward global decarbonization objectives) and in this case no double claiming issues would exist.

Ibid. Gold Standard, 2022.

[82] Nestlé's guidance is informed by the GHG Protocol's Land Sector and Removal Guidance and SBTi Forest, Land and Agriculture (FLAG) Guidance.

[83] Nestlé, 2023. Nestlé's Supply Chain (Scope 3) and Sourcing Landscape Removals Framework (2023). https://www.nestle.com/sites/default/files/2023-10/nestle-scope-3-removals-framework.pdf

[84] Ibid. Nestlé, 2023.

4. **Sourcing landscape**: Projects implemented on land that is connected environmentally and/or socio-economically to the supply shed from which Nestlé sources ingredients.

To address their largest identified indirect GHG emissions, Nestlé implements projects in their livestock and dairy supply chains. In 2023, the company claims these interventions produced absolute emission reductions equal to 13.29 million tonnes CO_2e compared to its 2018 baseline, of which 25% of the reduction occurred in their dairy and livestock sourcing value chain.[85] In the U.K., all of the company's fresh milk suppliers have been implementing regenerative agriculture practices since 2021. Regenerative agriculture practices within Nestlé's projects include improving soil health, supporting food security, restoring water resources, and enabling biodiversity.[86] One of these implemented practices was improving pasture composition by planting several species of grass to increase biodiversity. These regenerative farming insetting interventions also were reported to benefit soil and animal health. The company reports that the average GHG emissions of farms was reduced by 19% below the no-intervention scenario in the first two years.[87]

Nestlé's insetting framework requires independent third-party verification of their insetting projects to confirm these results. For the first three levels of connection *verification* is required, and for projects impacting the sourcing landscape *certification* is required (e.g., working through the Verra S3S or GS program) and verification is only required if intervention units are to be claimed as carbon credits.

Challenges to Expect when Insetting

Issues and lessons learned by insetting practitioners are identified by the International Platform for Insetting's (IPI) in "A Practical Guide to Insetting."[88] This guide identifies challenges similar to gathering supplier-specific information to inform more detailed scope 3 inventories, such as understanding material emission sources, supply chain risks, and establishing internal governance structures.[89] It further identifies external challenges of communicating and working with value chain partners to support mutually beneficial activities.

A significant challenge discussed throughout the GS Interventions Guidance is the issue of double counting. If a company makes a carbon credit claim from insetting intervention units there is the potential for double counting the impact of the intervention as a company's scope 3 emissions may be physically lower and then also counting the impact of the intervention

[85] Nestlé, 2023. Creating Shared Value and Sustainability Report 2023. Nestle.com. https://www.nestle.com/sites/default/files/2024-02/creating-shared-value-sustainability-report-2023-en.pdf

[86] Nestlé, not dated. Regenerative agriculture. Nestle.com. Accessed 12/18/2024. https://www.nestle.com/sustainability/nature-environment/regenerative-agriculture

[87] Creating Shared Value and Sustainability Report 2023 (Nestlé, 2023).

[88] Brandt S., et al., 2022. A Practical Guide to Insetting. International Platform for Insetting. March 2022. https://www.insettingplatform.com/insetting-guide/

[89] Brandt S., et al., 2022.

through the credits, which could be reported to claim further progress toward emission targets. In addition, companies that are not directly engaged in supporting or implementing an insetting intervention, but are impacted by an intervention (e.g., an intervention lowers a source of their value chain emissions), would benefit from a reduction in their scope 3 emissions. This would effectively be counting the intervention's impact a third time. Just like scope 3 emission sources may be counted in multiple corporate inventories, there is a danger that insetting avoided emissions or enhanced removals also will be counted by multiple parties. Companies are encouraged to report the emissions that actually occur in their GHG inventory.

The GS Interventions Guidance also states that "Companies should work with suppliers to build capacity and agree [on] approaches to minimize double claiming with other reporting companies."[90] This would help to clarify the claims a company can make to avoid double counting, but it presents significant practical challenges regarding the level of coordination with other companies and suppliers that would be required.

Also, there is the potential for an insetting intervention, for which a carbon credit claim is made, to be captured and claimed toward a country's NDC goal, a carbon crediting project, and again accounted as part of other forms of overarching external policies or mechanisms. If the intervention is claimed by the company that caused it and any other party through an external policy or mechanism, that could constitute double counting. It may be challenging to coordinate with all of these potentially overlapping entities to allocate who can claim what and avoid double counting concerns.

[90] Ibid., Gold Standard, 2022.

6. FREQUENTLY ASKED QUESTIONS ABOUT SPECIAL TOPICS IN GHG EMISSIONS ACCOUNTING

Purpose

This document is a curated list of frequently asked questions (FAQ), organized by topic area, that have come up over the course of the EPRI supplemental project on Special Topics in GHG Emissions Accounting for Electric Companies and Combined Utilities. Much of the material covered in the FAQ was sourced from the technical briefing papers prepared for each webcast identified in Table 1. For more detailed information, please consult the individual briefing papers included in this Compendium.

Audience

The primary audience for this FAQ is the staff members of the electric power companies and combined electric and natural gas utilities that participated in this EPRI supplemental project. This FAQ addresses questions and provides answers that are of interest to the project participants and takes into consideration these entities' principal activities. This FAQ does not include answers that may be relevant or complete for other entities that are not electric power companies or combined utilities.

General Questions:

1. In recent years, the U.S. Environmental Protection Agency occasionally has adjusted the Global Warming Potentials (GWPs) for methane (CH_4) and nitrous oxide (N_2O). When an electric company is reporting their GHG emissions data, is there a best practice with regards to which global warming values (GWPs) to use for reporting 2022, 2023, and 2024 data? According to US EPA[91], the GWP estimates presented in the most recent Intergovernmental Panel on Climate Change (IPCC) scientific assessment reflect the state of the science. In science communications, EPA will refer to the most recent GWPs from the IPCC's Sixth Assessment Report (AR6) published in 2021.

EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks* complies with international GHG reporting standards under the United Nations Framework Convention on Climate Change (UNFCCC). UNFCCC guidelines currently require the use of the GWP values from AR5, published in 2013. EPA's voluntary CH_4 reduction programs also use CH_4 GWPs from the AR5 report to calculate CH_4 emissions reductions through energy recovery projects, for consistency with the national emissions presented in the US GHG Inventory. EPA's Greenhouse Gas Reporting Program generally uses GWP values from AR4 to determine whether facilities exceed reporting thresholds, and to publish data in CO_2 equivalent values.

[91] https://www.epa.gov/ghgemissions/understanding-global-warming-potentials . Accessed 3/4/25.

It is up to an electric company to decide which GWPs to use when reporting its GHG emissions in its annual emissions inventory in terms of CO_2 equivalent totals. Typically, the reporting program used by the electric company (e.g., The Climate Registry, U.S. Environmental Protection Agency) will provide guidance on the appropriate GWPs to use for inventory reporting purposes.

Absent specific guidance from a reporting program or state or federal agency, it is good practice for electric companies to use the most recently published GWPs associated with the most recent IPCC Assessment Report which currently is AR6. If an electric company used different GWPs to report its emissions in previous years, the company may wish to consider updating its past reporting to reflect the updated GWP values. Alternatively, going forward, a reporting company could report its emissions in the future based on the GWP values it used in the past along with reporting based on the updated GWP values.

Technical Webcast 1: Accounting and Reporting for Electricity and Natural Gas Transmission and Distribution Related Emissions

1. **Scope 3, Category 3: Fuel- and Energy-Related Activities is broken down into four activities. As an electric company, we have identified emission sources associated with each of the four activities. Do we need to calculate the GHG emissions associated with each of the activities individually?**
   Each of these activities has different emission sources and boundaries; hence, it is important to estimate emissions associated with each activity individually. Additionally, this approach will be more transparent making it possible for company staff and others to identify which activities are contributing to the company's scope 3, category 3 emissions.
2. **This past year our GHG emissions inventory was audited externally. Our inventory originally included upstream emissions associated with "wheeled" energy (MWh) being delivered to our company across bulk transmission lines within Scope 3, Category 3: Fuel- and Energy-related emissions. However, the auditor suggested these emissions should be removed from our inventory. Is this a good accounting practice?**
   The accounting for GHG emissions associated with wheeled electricity is complex. The GHG Protocol is clear, however, that scope 3, category 3, activity D includes emissions from purchased electricity sold to end-users. In addition, if the wheeled electricity was purchased from a third party for delivery by the reporting company to another intermediary or end-use customer, all upstream emissions associated with the total amount of wheeled energy also would be included in scope 3 category 3, activity D. In addition, these reported scope 3 emissions also would include the T&D line losses associated with the wheeled electricity because these line losses would be included in the "gross" amount of electricity purchased to be wheeled.
   However, if an electric company was operating as a "common carrier" providing only transmission services associated with the wheeled energy, then it would be possible for the electric company to not report these emissions under scope 3. This would only be the case if the reporting company did not take ownership of the electricity being transmitted across its T&D infrastructure. This option is one of those presented in chapter 2 – and it is the least

conservative of the suggested approaches to account for GHG emissions related to common carrier T&D infrastructure.

3. **Is it correct for an end-use electricity consumer only to report as their scope 2 emissions the electric company's direct scope 1 emissions associated with the electricity they purchase? Can an end-use consumer not report in its own scope 2 emissions inventory the scope 2 emissions associated with the line losses reported by the electric company?**
   Yes. If an electric company generates and delivers electricity to end-use consumers (e.g., a vertically integrated electric utility), the company's total reported scope 1 emissions typically would include both the direct emissions associated with generating the electricity to meet the end-use consumer load and the T&D line losses associated with delivering the electricity to the end-use consumer.
   As defined by the GHG Protocol Scope 2 guidance and Corporate Standard, scope 2 emissions for end-use electricity consumers only include the indirect emissions associated with the electricity they consume and does not include the emissions associated with the T&D line losses to deliver the electricity to the end-use consumer. An end-use customer typically estimates and reports its scope 2 emissions by multiplying the amount of electricity it consumed (MWhs) by the average grid GHG emission factor (tCO_2/MWh) for the electricity grid where the customer uses the electricity, or by an EF provided by their local electric company for the electricity the end-use consumer purchased and consumed.
   The accounting for line losses occurring prior to electricity consumption by the consumer is reported by end-use customers under scope 3, category 3, activity C (line losses). In this category, end-users report all upstream emissions associated with T&D line losses resulting from their consumed electricity, including emissions associated with the extraction and processing of fuels used to generate the electricity and combustion emissions from generating electricity "consumed" by the T&D line losses).
   Under category 3 activity B (upstream emissions of purchased electricity), end-users report all upstream emissions associated with the amount of electricity the end-use customer actually consumed, including emissions from raw material extraction up to the point of, but excluding, combustion by a power generator.
4. **How would a shipping or trucking company deal with an analogous situation? Would they report the emissions associated with all the materials they are shipping?**
   Under the GHG Protocol, shipping and trucking companies report the GHG emissions from their trucks and fleet vehicles as scope 1 direct emissions. In some cases, trucking and shipping companies may be acting as "common carriers" that do not purchase or otherwise take ownership of the goods they are transporting. In these cases, shipping and trucking companies would still report the emissions associated with their trucks and vehicle fleets as scope 1 direct emissions.
   There is other existing GHG reporting guidance for transportation companies which excludes emissions sources from transported goods, such as the *Global Logistics Emissions Council Framework v3.0* or *ISO 14083:2023: Greenhouse gases – Quantification and reporting of greenhouse gas emissions arising from operations of transport chains*– which is sector specific and not within the Scope 3 Standard framework.

5. **How would an electric company that owns T&D infrastructure account for "use of sold products" in their scope 3 GHG emissions accounting?**
   Scope 3, category 11: use of sold products refers to GHG emissions released during the use phase of a company's product. In the case of supplied electricity, all emissions occur prior to its consumption by an end-use consumer, so there is no need for an electric company to report scope 3, category 11 emissions associated with the use of electricity the company sold.

Technical Webcast 2: Market-based Versus Location-based GHG Emissions Accounting

1. **Is it appropriate for a vertically integrated electric utility to report only T&D line losses as scope 2 emissions?**
   No. In general, the direct scope 1 emissions reported by a vertically integrated electric power generator would implicitly include the scope 2 indirect emissions associated with transmitting the generated electricity across the company's T&D infrastructure. Consequently, there is no need for a vertically integrated electric company to separately report the scope 2 emissions associated with transporting electricity the company generated across its own T&D system(s).
2. **Given that the same emission sources are included when calculating both market-based and location-based emissions, would there be double counting across location- and market-based emissions?**
   The two techniques quantify the emissions from the same sources by applying different methodological approaches. Since market- and location-based emissions are reported separately, and are not combined, there is no double counting of GHG emission sources.
3. **How can electric companies provide their end-use customers with an EF that is relevant to their specific electricity consumption?**
   If an end-user is directly connected to an electricity generating unit that provides the end-user with all of the electricity they consume, then the generation-specific EF s relevant and appropriate.
   If the end-user is served by a regional power grid, a geographically appropriate grid-average EF is relevant and can be used. Under the existing GHGP Scope 2 Guidance, utility-specific EFs (in a shared grid) are only allowed to be used for scope 2 GHG reporting using the market-based method.
   Typically, it is not possible for electric companies to provide their grid-connected end-use customers with customer-specific EFs to help their customers calculate the scope 2 emissions associated with the electricity they purchase. This is largely due to the physical dynamics of how electricity "moves" through the power grid.[92] Today, there is no widely agreed upon method for electric companies to do provide end-use customers with these "consumed" electricity EFs, reflecting the physical reality of electricity and our limited ability to trace electricity from a generator through T&D lines to an end-user.

[92] Please refer to this GHGMI blog post for more information about this.

For a discussion of alternative approaches that can support this goal, see *Methods to Account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases*, EPRI, Palo Alto, CA: 2019. 3002015044. This report examines the greenhouse gas (GHG) accounting methods in use by various GHG reporting programs and jurisdictions in the United States and internationally to account for electric company GHG emissions, with a focus on the accounting for indirect CO_2e emissions associated with wholesale power transactions for delivery to retail end-use customers. It describes different GHG accounting options available to account for the GHG emissions associated with electric power sold to end-use consumers.

Technical Webcast 3: Base Year Recalculation

1. **A significance threshold is described as a percentage change relative to a company's GHG emissions base year inventory. Is there guidance on whether a company should consider the emissions activity within a single scope or the entire inventory?**
   A reporting company has the prerogative of setting separate base years for individual scopes or setting one base year for their entire inventory (i.e., cumulative scopes 1, 2, and 3). The significance threshold is applied to all base years that a reporting company may have. In the event a reporting company has multiple, separate base years for individual scopes, the significance threshold would be applied to those base year inventories (i.e., to the scopes individually). However, if the reporting company has a single base year for their entire inventory, then the significance threshold needs to be considered across all scopes.
2. **In the electric utility sector, there are power plants and other assets that are often jointly owned by two or more companies. Frequently, the relative percentage of the asset owned by the reporting company changes. If this occurs, is it a structural change that might require the base year to be recalculated?**
   Yes. The same principles apply to a change in equity share and structural changes at the asset level. If the change in the equity share changes the amount of GHG emissions reported in the inventory more than the significance threshold, then the base year should be recalculated.
3. **If a reporting company sells a coal-fired power plant and then buys electricity generated from the coal plant back through a power purchase agreement (PPA), this will shift the categorization of the GHG emissions from scope 1 to scope 3, category 3: fuel and energy-related activities. Does the reporting company need to recalculate its base year in this situation?**
   It depends. The shift in ownership of the power plant is considered a structural change, which would typically trigger a recalculation (assuming that change meets the significance threshold). However, if the reporting company previously reported emissions for scope 3, category 3, then a recalculation is not triggered.

4. **If a company changes their base year when acquiring an asset and the base year emissions increase as a result, what are the implications of that acquisition on a company's GHG reduction target?**
   If the asset acquired by the reporting company is *new* (i.e., it did not exist prior to the acquisition), then the acquisition would be considered organic growth. In cases of organic growth or decline, a recalculation is not triggered. However, if the asset existed before the acquisition and was acquired from another company, the ownership of the asset has shifted. In this case, the acquisition would be considered a structural change which would trigger a recalculation.
   In this question, it is assumed that the reporting company has changed its base year. This can either mean the reporting company recalculated their base year, or they moved their base year to the current inventory year when the asset was acquired. In any situation where the base year changes (via a recalculation or otherwise), any GHG targets that are set relative to the previous base year will need to be reconsidered and adjusted to reflect the updated base year. In this example, the base year emissions increased, making it more challenging for the company to achieve its GHG emissions target.

Technical Webcast 4: Insetting

1. **What is the difference between consequential and allocational GHG emissions accounting?**
   Consequential accounting seeks to quantify a change (or potential change) in GHG emissions caused by a specific GHG mitigation intervention (e.g., GHG emissions offset crediting projects, a new policy, or changes in management practices). Consequential accounting is used to estimate the emissions impact of carbon crediting projects, and other actions or intervention intended to avoid GHG emissions or enhance GHG removals.
   Allocational accounting (aka attributional emissions accounting) allocates responsibility for emissions from activities to entities. It tracks absolute emissions over a time series, and for corporate accounting (which is a subset of allocational accounting) it classifies emissions into scopes 1, 2, or 3. Allocation emissions accounting is the type of emissions accounting done by corporations to prepare and report their annual GHG emissions inventory.

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