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Integrated Greenhouse Gas
Accounting Guidelines for Carbon
Dioxide Capture, Utilisation and
Geological Storage

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IEA Greenhouse Gas R&D Programme

Integrated greenhouse gas accounting guidelines for carbon dioxide capture, utilisation and geological storage

Final Guidelines

Carbon Counts Company (UK) Ltd

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SUMMARY

This report sets out accounting guidelines for measuring greenhouse gas (GHG) emissions and emissions reduction effects arising from technologies involving carbon dioxide capture, utilisation and geological storage (CCUS).

The guidelines apply a project- and product-based approach to measure GHG emission reduction effects, based on comparing the emissions for a CCUS activity (project or product) with the emissions from a comparable activity delivering the same product or service.

A modular approach is applied. Firstly, users calculate the GHG effects arising from the capture (and transport) of CO₂ based on the avoided emissions from providing the same service or product as output from the CO₂ source facility, but without CO₂ capture.

The resulting estimate of GHG effects from CO₂ capture is carried forward to the utilisation or storage step. In this subsequent step, the GHG emissions from providing the same service without using captured CO₂ is estimated and compared to the GHG emissions of providing the service using captured CO₂. This provides an overall estimate of the cradle-to-gate GHG effect of CCUS activities.

Additional guidance is provided on cradle-to-grave assessment, although this is not the primary focus of these guidelines – the Guidelines focus on annualised GHG emissions accounting cycles rather than whole life emissions analysis.

Specific guidance is provided on, *inter alia*:

- Managing system multifunctionality in carbon dioxide utilisation (CCU) activities
- Handling functional equivalence and selecting functional units for CCUS activities
- Managing the risk of CO₂ seepage from geological storage sites.

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1 INTRODUCTION

This document sets out integrated greenhouse gas (GHG) emissions accounting guidelines applicable to the following activities:

1. Carbon dioxide (CO₂) capture
2. CO₂ transportation
3. CO₂ utilisation
4. CO₂ geological storage

The concepts, principles, definitions and methodologies presented herein can be used to quantify and assess GHG emissions, emissions reduction and climate change mitigation benefits arising from these activities – and associated products and services – both before (*ex ante*) and after implementation (*ex post*).

Methods presented follow-on from previous guidelines that set out procedures for systematically accounting for GHG emissions and evaluating benefits of CO₂ utilisation technologies (CCU): IEAGHG, 2018, Greenhouse Gas Emissions Accounting for CO₂ Capture and Utilisation Technologies v1.0 – referred to hereafter as “CCU Guidelines v1.0”. Many of the approaches presented in the CCU Guidelines v1.0 are carried over and refined herein.

The guidelines also draw on and align with selected international standards, guidelines and regulations for GHG emissions accounting for CO₂ capture and geological storage (CCS).

1.1 Aim and Purpose

The guidelines are primarily aimed at operators but are also of interest to administrators and regulators tasked with overseeing carbon capture, utilisation and storage (CCUS) activities. The methods presented offer a means to consistently assess, evaluate, monitor and report GHG emissions, emissions reduction and climate change mitigation benefits arising from such activities, which is of interest to a range of stakeholders.

Application of the guidelines supports development of national policies and regulations for climate change mitigation using CCUS. It partly implements methodological requirements consistent with Intergovernmental Panel on Climate Change (IPCC) guidelines for the compilation of national GHG inventories (IPCC, 2006). The IPCC guidelines presently form the basis for tracking progress against nationally determined contributions (NDCs) made pursuant to the Paris Agreement to the United Nations Framework Convention on Climate Change (UNFCCC). For this reason, national policies and measures may align with these standards to ensure effective tracking of climate ambition, meaning that the guidelines offer wide applicability to many parts of the world.

1.2 Background

In reviewing the CCU Guidelines v1.0 (IEAGHG, 2018), some stakeholders considered that it would be useful to establish an integrated accounting methodology covering both CCU and CCS, views which provided the basis for preparing this integrated CCUS accounting guide.

To help inform the design approach for the integrated guide, a review of various GHG accounting schemes was undertaken to assess how they incorporate both CCU and CCS, and to identify areas of commonality around which to build a consistent methodological framework.

Two key issues for design were identified in the review:

- ❑ CCU is presently not recognised as an emission reduction approach under most carbon pricing schemes and GHG reporting programmes around the world. For example, neither the IPCC National GHG Inventory Guidelines (IPCC, 2006), the European Union GHG emissions trading scheme (EU ETS), nor the GHG reporting program in the US fully allow for CO₂ sent for utilisation to be deducted from a national or facility GHG emissions inventory.¹ Conversely, CCS is recognised and allowable under such schemes, and relevant GHG accounting and monitoring guidelines exist.
- ❑ The focus of accounting approaches developed for CCU to-date have tended to be product-based, whereas CCS is more focussed on facility-based accounting methods. The latter fit more clearly to carbon pricing and sectoral and national emission reduction policies aimed at reducing emission from anthropogenic sources of GHGs. Consequently, the methods thereunder apply commensurately narrow, facility-level, accounting boundaries relevant to major CO₂ sources and means to address downstream 'leakage'. Conversely, product-based accounting for CCU implies the need for more holistic, life cycle based approaches that employ wide boundaries and include the dynamics of product markets, product use and disposal, and the counting of potential environmental benefits arising from the substitution of conventionally-produced incumbent products with CO₂-derived alternatives. This difference poses some challenges to creating an integrated accounting approach.

The review concluded that either a product-type approach be developed for CCS so as to align with CCU accounting methods, or that a project-based accounting method be used that incorporates wide and variable boundaries that are able to capture the slightly differing characteristics of the technologies.

Adopting a product-based approach to CCS involves considering geological storage of CO₂ as a 'service' that is comparable with the provision of CO₂-derived products. The choice of functional unit for CCS presents a challenge for aligning the technologies, however; the only logical functional unit is tonnes CO₂ stored, whereas for CCU the most logical functional unit is typically the mass, volume or energy content of the CO₂-derived product. Using tonnes CO₂ utilised as the functional unit for assessing CCU poses limitations, the primary problem being that it does not offer clear indications of downstream GHG effects occurring in product markets, as discussed further below. Differences in functional units mean that product-based methods present some complication for alignment, and ultimately requires a bifurcated approach to each CO₂ pathway. Another issue is that product-based approaches tend to take a whole life perspective, whereas a key aspect of GHG accounting under climate policies is the application of annualised monitoring, reporting and verification (MRV) cycles which allow the tracking of progress of emission reduction targets and actions. The review concluded that a product-based approach could offer some new perspectives on the technologies, albeit fairly limited given the factors described.

¹ Except where CO₂ utilised for enhanced oil recovery (EOR)

Project-based accounting was also considered to have merits. A project-based approach, in essence, is a disaggregated product-based method where the GHG inventory and GHG effects are calculated at a project-level rather than normalised against a functional unit of product or service. The results from project-based accounting calculations can be readily normalised to a relevant functional unit so as to provide a product- or service-based GHG emissions intensity estimate. Showing the full-chain project GHG inventory and its subsequent conversion to a product GHG intensity using a clear functional unit can greatly enhance transparency of GHG emissions accounting by showing all assumptions and emissions sources included in the product-based assessment. Project-based approaches usually also involve applying annualised accounting cycles rather than whole-life accounting, although either can be done.

Based on these conclusions, no clear candidate approach was identified. It was therefore decided that the integrated CCUS guidelines employ a combined product- and project-based approach, where the calculated product or service benefit is also converted to a project GHG inventory to show the overall estimate of GHG effects and potential emissions reduction. The focus is also more on annualised MRV cycles rather than whole-life GHG assessment.

1.3 Outline of the Guidelines

The first few sections of the guidelines provide the definitions employed throughout, a description of the concepts and approaches employed and the principles that must be followed during application.

Subsequent sections provide GHG accounting modules outlining methods applicable for each part of the CCUS project chain, and the monitoring, reporting and verification requirements to support *ex post* implementation.

2 DEFINITIONS

For the purposes of this guideline, the following definitions apply.

Additionality

The characteristic of a specific activity or intervention to generate GHG emission reductions that are additional to what would have happened otherwise under a counterfactual scenario (i.e., under a business as usual scenario that would occur without the intervention).

Avoided emissions

The net GHG emissions reduction achieved by CO₂ capture, taking account of the additional emissions created, including by the energy penalty (see: Energy penalty).

Biogenic CO₂

CO₂ derived from biomass, but not from fossilized or fossil sources

Boundary (Assessment)

A GHG assessment boundary should encompass all emissions sources needed to characterize and quantify the primary and secondary GHG effects attributable to a CCUS activity. It may be defined by spatial (geographical), organisational and temporal GHG effects, which may lead to differences in boundary with certain omissions or inclusions.

Caprock formation

A layer or formation of low porosity and permeability rock overlaying an injection formation that is of sufficient thickness to prevent the upward movement of stored CO₂ due to buoyancy from the injection formation.

Captured carbon dioxide (CO₂)

Carbon dioxide that is obtained through CO₂ capture processes, including direct air capture.

Carbon dioxide (CO₂) capture

Processes for separating and concentrating CO₂ from dilute streams as contained in waste gases generated by industrial and energy-related sources, or from the atmosphere (direct air capture).

Carbon reversal

The possibility of reversing positive GHG effects of CCUS due to impermanence of carbon storage.

Carbon storage

Retention of carbon captured from fossil, biogenic or atmospheric sources in a carbon pool other than the atmosphere.

CO₂ benefit factor

A factor reflecting the inherent GHG emission reduction benefit arising from use of captured CO₂ in processes and products.

CO₂ enhanced oil recovery

A process involving the use of CO₂ as a solvent that, when injected into an oil reservoir, acts to enhance the recovery of residual oil in mature oil fields by increasing its viscosity and pushing it through a reservoir to production wells.

CO₂ plume

The body of injected CO₂ in a subsurface geological formation.

CO₂ utilisation

Processes involving the use of CO₂ molecules in liquid or gaseous form to either synthesize new chemical products or as a working fluid (as in CO₂ enhanced oil recovery).

CO₂-derived product

A product fabricated using chemical synthesis of CO₂ molecules that are either captured from a point source emission or directly removed from the atmosphere (see: Captured CO₂; Direct air capture)

Combustion emission

Emissions arising from the combustion of biogenic or fossil fuels.

Cradle-to-gate assessment

A method of partial life cycle assessment that measures GHG effects from resource extraction to the factory gate (i.e., before it is transported to end users). It can be applied across an annualised measurement cycle.

Cradle-to-grave assessment

A method of complete life cycle assessment measuring GHG effects from resource extraction to the product use, disposal and end-of-life. It therefore involves multi-year, full product life, analysis.

Direct air capture

Technologies that capture CO₂ directly from the atmosphere. These activities are accounted for as a GHG removal.

Downstream emissions

GHG emissions associated with processes that occur in the life cycle of a product after the CO₂ capture and transport stage in a CCUS process chain.

Energy penalty

The additional energy required to operate CO₂ capture equipment.

Fossil CO₂

The product of oxidation of carbon contained in fossilized material upon combustion.

Fugitive emission

Emissions of GHGs from leaking equipment or other intended or unintended releases of gases, including captured CO₂, during transport and processing of CO₂.

Functional equivalence

The property of two or more products or services providing an identical and interchangeable function or level of performance.

Functional unit

The unit of comparison used in quantified performance assessment of a product system and for use as a reference unit. It also refers to the unit of choice for the denominator employed to normalise a comparative GHG assessment into an emissions rate for a given unit of product or service, for example, tCO₂ reduced per tCO₂ captured (where tCO₂ captured is the functional unit).

Gate-to-gate

A method of partial life cycle assessment measuring GHG effects only across a single stage of a process chain (e.g., a single facility). It can be applied across an annualised cycle.

Geological CO₂ storage site

A paired geological formation, or a series of such formations, consisting of an injection formation coupled with an overlying caprock formation (see *caprock formation* and *injection formation*).

GHG assessment

A method of assessing GHG effects arising from the implementation of an activity relative to an alternative, counterfactual, baseline or reference scenario.

GHG effects

Changes in GHG emissions, removals or storage caused by interventions (e.g., policies, projects, products) in conventional process chains, typically involving technology innovations such as CCS and CCU.

GHG intensity

The GHG emissions associated with the supply of one functional unit of product or service.

GHG project

An activity or set of activities intended to reduce GHG emissions, increase the storage of carbon or enhance GHG removals from the atmosphere.

History matching

The process of comparing observed results from the monitoring and measurement of a geological storage site performance with the results of the *ex ante* predictive numerical modelling of the behaviour of CO₂ injected into the geological storage site, and the use of the observed results to calibrate and update numerical models and modelling results. It can involve multiple iterations.

Injection formation

A carefully surveyed and selected geological formation of relatively high porosity and permeability into which CO₂ is injected for storage.

Intermediate product

Output from a unit process that is an input to other unit processes involving further transformation within a process chain.

Life cycle

Consecutive and interlinked stages of a process chain, from raw material acquisition or generation of natural resources to end of life, inclusive of any recycling or recovery activity.

Life cycle assessment (LCA)

Compilation and evaluation of inputs, outputs and potential environmental impacts of a process chain throughout its life cycle.

Leakage

Changes in GHG emissions occurring outside of a GHG assessment boundary but attributable to the activity or process chain.

Overburden

Rock and/or soil overlying a geological storage site, forming part of the surrounding domains.

Perfect substitution

Circumstances where the supply of an alternative product does not affect demand, and the alternative product can be used in exactly the same way as the equivalent conventional product that it displaces in a market (see: Functional equivalence).

Permanence

Ability of a CCUS process chain to retain captured CO₂ in terrestrial carbon pools other than the atmosphere for a prolonged or indefinite period of time.

Primary product

A CO₂-derived product (intermediate or final) or the provision of a geological CO₂ storage service (see: CO₂-derived product).

Process chain

A sequence of linked activities and processes making up a life cycle of a project or product.

Removal (GHG)

Absorption and isolation of greenhouse gases from the atmosphere.

Seepage

Fugitive emissions of captured CO₂ from a geological storage site which can occur through diffuse pathways (e.g., through caprocks) and confined pathways (e.g., along fault planes and fissures or through operational or abandoned wells).

Secondary product

The product or service delivered by a facility from which CO₂ is captured.

Surrounding domains

Surrounding domains are areas in the lithosphere overlying, underlying and lateral to a geological CO₂ storage site (including the overburden). It should cover geological features that

may be affected by CO₂ injection activities, such as faults, fractures, fissures and wells, that could be activated by subsurface processes and create pathways for CO₂ migration and seepage. Surrounding domains may be identified using geological survey methods and behaviour examined using computational simulation models of the subsurface.

3 PRINCIPLES

Users of these guidelines wishing to undertake systematic calculation and assessment of the GHG emissions and GHG emissions reductions of CCUS processes, projects and products, and make consistent estimates of GHG effects, shall adhere to the principles set out below.

Relevance

GHG emissions and removals data and methods appropriate to the assessment of the GHG emissions arising from specific processes, projects and products must be employed, and the information must be presented in a way that is understandable to the user.

Completeness

All GHG emissions and removals arising within the CCUS assessment boundaries for a specified process, project or product which provide a material contribution to the assessment of GHG emissions and emissions reduction arising from that process, project or product should be included.

Consistency

Assumptions, methods and data must be applied in the same way throughout the quantification and support reproducible, comparable outcomes, and allow for comparability over time.

Transparency

The results of GHG assessment carried out must include sufficient GHG emissions-related information to support disclosure and allow any user to make associated decisions with confidence.

Conservativeness

Assessed GHG emissions reductions should not be overestimated. Where there is uncertainty regarding assumptions and data, conservative assumptions should be used. Conservative assumptions are ones that are more likely to underestimate than overestimate any GHG emissions reduction effects.

Accuracy

Bias and uncertainty must be reduced as far as practical.

Other principles and good-practice implementation steps shall also be followed in related documentation referred to in Section 5.4.

4 CONCEPTS

This chapter sets out the basic GHG accounting concepts which form the basis of the methods set out in these guidelines. A basic description is provided of the topic, its relevance to CCUS activities, and how it is embedded into the guidelines.

4.1 GHG emissions inventories

Human activities such as the combustion of fuels, industrial processes, agriculture, land use, land use change and forestry result in the emissions of anthropogenic GHGs to the atmosphere and/or the enhancement of GHG removals from the atmosphere by sinks. Measurement of the level of such activities, and the related emissions and removals, is accomplished through the compilation of *GHG emissions inventories*.

A GHG emissions inventory can be developed for a wide range of purposes and at different scales, including:

- global scale (total world GHG emissions, covering sources of anthropogenic GHG emissions to atmosphere and removals by GHG sinks)
- a country (a national GHG inventory of all emissions and removals)
- a sector (emissions from, for example, power, iron & steel, cement, transport, managed forestry, agriculture)
- an installation or facility (e.g., emission from a factory or power plant)
- a corporation or organisation (a corporate GHG inventory. These may cover multiple installations, sectors and countries)
- a policy (e.g., domestic energy efficiency labelling; targets for low carbon power generation)
- a programme (e.g., roll-out of solar water heater or efficient cooking stoves)
- a project (e.g., related to a specific infrastructural development or integrated GHG mitigation activity)
- a product (e.g., product life-cycle emissions accounting for, for example, a food item or as applied in, for example, low carbon fuel standards for fuel products)
- an event of activity (e.g., a “carbon footprint” of a flight, rail or car journey, or all emissions associated with, for example, a conference)
- an individual (a personal “carbon footprint”)

In each case, different approaches, tools and methods may be used to take account of different features of the GHG inventory being compiled, and a large and growing body of guidance exists which provide methods for their development.

The exact emissions sources and removals by sinks that must be included in a GHG inventory are based on the choice of *assessment boundary*, which may include or exclude certain sources depending on where the boundary cuts-off. It has both spatial/ownership considerations (which emission sources? Where? Under who’s control?) and temporal aspects (for how long must emission sources be measured and assessed? Which period of time does the GHG inventory apply to?). In all circumstances, a complete and accurate GHG assessment should seek to include

all identifiable emission sources and removals by sinks in the assessment boundary that are relevant to its goal.

Measuring and comparing changes in GHG emissions and removals over time and/or relative to an alternative scenario provides the basis for measuring GHG effects of a given action or intervention, as described further below.

Choices around the assessment boundary are a key feature for any GHG assessment, including for CCUS technologies. It must take account of spatial (geographical), organisational and temporal dimensions of GHG effects.

These guidelines provide methods by which to collect data and compile a GHG inventory for a CCUS project, process or product taking into account spatial, organisational and temporal factors.

4.2 GHG effects

An understanding of whether and how implementation of a new project, product or policy activity generates a climate mitigation benefit by reducing GHG emissions to the atmosphere is achieved by measuring and quantifying its *GHG effects*.

The WBCSD/WRI (2004) categorize GHG effects as primary and secondary:

- ❑ **Primary GHG effects.** The intended change(s) in emissions resulting from implementation of a new project, product or policy activity. A primary GHG effect is defined as a change in emissions relative to an alternative project, product or policy that delivers the equivalent product or service using a different technology or service method (i.e., the *baseline or reference emissions*; Figure 4.1).
- ❑ **Secondary GHG effects.** Unintended change(s) in emissions caused by the project, product or policy. They are often small relative to the primary mitigation effect, and may also be neutral, positive or negative. In the case of negative effects, these can undermine the primary GHG effect, whilst positive effects act to enhance the overall mitigation outcome. WBCSD/WRI (2004) note two categories of secondary effect:
 - *One-time effects.* Changes in the GHG emissions associated with the construction, installation, and establishment or the decommissioning and termination of the project.
 - *Upstream and downstream effects.* Recurring changes in GHG emissions associated with the project (upstream) or products (downstream) relative to the baseline – sometimes referred to as *leakage*.

Process chains involving CCUS – and CCU in particular – often create a wide range of primary and secondary GHG effects, which must be measured in order to comprehensively analyse and understand whether, how and where emissions reductions occur as a result of project implementation and CO₂-derived product supply.

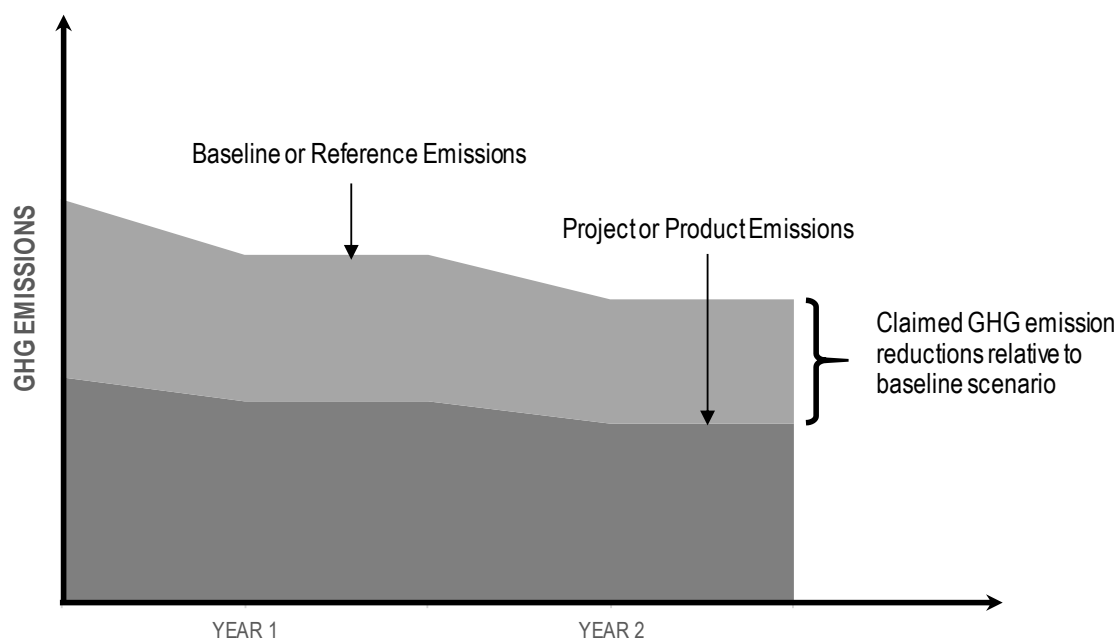
The primary purpose of these guidelines is to provide methodologies and procedures for measuring GHG effects arising from CCUS project implementation and product supply.

4.3 Measuring GHG effects

Emissions reduction arise from positive GHG effects, which can be measured and quantified by comparing the GHG inventory of a new activity (project, product or activity emissions) – expressed either on an intensity-basis in product methods or the full process chain in project methods – with the GHG inventory of an alternative, counterfactual, activity (the baseline or reference emissions). This type of analysis is termed a *GHG assessment*.

The difference between the emissions from the new activity and the possible emissions under the counterfactual baseline scenario provides the basis for making a quantified GHG assessment of the GHG effects, predicated on the assumption that the new activity substitutes the alternative scenario. The relationship between project or product emissions and baseline emissions is shown schematically below (Figure 4.1).

Figure 4.1 Quantifying GHG reductions from CCUS projects relative to a baseline



Source: based on WBCSD/WRI, 2004

These guidelines employ a part product- and part project-based approach to assess the GHG effects and potential emissions reduction arising from CCUS technologies implementation on an integrated basis.

4.4 Baselines

Several components make up the formation of baselines or reference cases for a project or product GHG assessment, including the *baseline scenario* and the *baseline emissions*.

4.4.1 Baseline scenarios

Baseline candidates are alternative technologies that could deliver the equivalent product or service as provided by the implemented new activity, and that are feasible within a relevant geographical and temporal range.

The baseline scenario is the selected baseline candidate that best reflects the economic, technological and regulatory alternative in the particular circumstances of the activity, as would have happened if the new activity was not implemented; in other words, a counterfactual scenario or business as usual scenario.

General options for baseline scenarios include (after WBCSD/WRI, 2004):

- Implementation of the same technology or practice used in the new project or product activity (i.e., a baseline candidate of the implemented project or product scenario);
- Implementation of another baseline candidate; or
- Continuation of current activities, technologies or practices that provide the same type of product(s) or service(s) as the new activity.

The choice of baseline scenario usually depends on the application of baseline procedures to select the most appropriate alternative from a range of baseline candidates.

The choice of baseline or reference product(s) and/or service(s) is a critical part of any GHG assessment of CCUS, because differences in approach can significantly modify the outcome of the analysis in terms of estimated GHG effects.

These guidelines provide guidance on aspects to consider when identifying and selecting possible baseline candidates and baseline scenarios for CCUS.

The exact choice of baseline scenario will be highly dependent on jurisdiction- and sector-specific circumstances that have influences on technology choices in relevant regions and industries and at a particular point in time.

Additionality

Additionality is a type of baseline procedure that employs qualitative and quantitative methods to assess and identify the most appropriate baseline scenario from a range of candidates. The additionality process involves applying a range of tests to the identified baseline candidates, covering technical (e.g., is it standard practice in the sector?), legal (e.g., are there legal requirements to implement the technology?) and economic (e.g., is the project or product the most economically viable option?). These aspects help to identify the most likely baseline scenario. Additionality assessments must include the new project or product scenario as a baseline candidate.

The procedure has merit in considering whether a policy intervention – such as implementation of a carbon pricing instrument – affects investment behaviour and therefore stimulates changes in technology solutions for providing a given product or service.

The novelty of all CCUS technologies mean that the baseline scenario at the current time is unlikely to be implementation of the same technology or practice as used in the new project or product. In other words, any investment into CCUS at the current time is very likely to be *additional*. For this reason, additionality assessment is not a significant feature in these guidelines.

Validity of baseline scenario

Projecting further out into the future poses greater questions and uncertainty of the relevant counterfactual baseline scenario. Technologies which are novel today may be the norm in future, and thus, the selected baseline candidate has only time-limited validity and should be periodically re-tested over time.

These guidelines take account of the possibility for changes in the validity of a selected baseline scenario and outline requirements for periodic re-assessment.

4.4.2 Baseline emissions

Baseline emissions are the calculated or measured GHG inventory of the selected baseline scenario. The GHG inventory must include all the potential emission sources that would be attributable to providing the equivalent services and/or products as the new activity.

Three methods are generally used to determine the level of baseline emissions:

- Historical emissions.** Where available, the historical emissions prior to the implementation of a new activity can provide a relevant estimate of emissions;
- Performance standard/benchmark.** Estimation according to a standardised numerical GHG emission rate (GHG intensity) for provision of a given product or service using alternative technologies. An example is the use of a standardised emission factor for an alternative type of power generation technology, the use of an electricity grid emission factor or the reported life-cycle GHG intensity of supplying a competing product.
- Project or product specific.** Calculation according to specific circumstances of the project or product activity.

Baseline emissions may be estimated on a GHG intensity basis according to the relevant functional unit of the GHG assessment (see below). Alternatively, the baseline emissions inventory can be calculated on an absolute project basis by multiplying the level of product or service delivered in the project or product scenario by the GHG emissions intensity of the alternative, counterfactual, method of delivering the same product or service in the baseline scenario.

All of the baseline emission methods described may be relevant to a GHG assessment of CCUS technology. Moreover, since CCUS consists of a chain of technologies that can deliver multiple differing products or services, different methods, different rate functions and different units all need to be accounted for in a GHG assessment.

These guidelines provide methods for accounting for this type of system *multifunctionality* in GHG assessments of CCU process chains.

In addition to the GHG emissions approach applicable to the baseline scenario, there are several other important factors that influence calculated baseline GHG emissions, as described further below.

Equivalence of products and services

The technology implemented with a new project or product activity leads to the output of system services and/or products that are supplied into a broader market. It is generally assumed that the same market demand would be fulfilled by an alternative technology if the project or product were not implemented. It is also generally assumed that the outputs of the new activity and the alternative, baseline, technology are functionally equivalent in terms of both quantity and quality of service and interchangeability. Thus, if the implementation of the new activity leads to the provision of same quantity and quality of outputs but with lower GHG emissions, positive GHG effects occur (i.e., emissions reduction).

Functional equivalence is a key topic in life cycle analysis (LCA) and has therefore also gained significance in the field of CCU in respect of product GHG assessment. Functionally-equivalent performance means that a new activity can generate products and/or services that can directly substitute existing, conventionally-derived, products or services on a 1 to 1 basis ('perfect substitution'). If a new project or product improves or reduces the quantity and/or quality of the product or service provided, however, then the substitution rate is rather 1 to 'X', resulting in different GHG effects which must be accounted for in the GHG assessment.

Assessment boundaries are also an important factor in assessing functional equivalence in terms of where in the CCU process chain the comparative assessment is made (see below).

Despite presenting some complexities in terms of GHG assessment, these guidelines offer practical approaches to simplify GHG assessments of CCU technologies, based on sound and rational understanding of issues relating to functional equivalence.

Assessing GHG effects is generally underpinned by an assumption that changes in the method of production or service provision has no effects on demand. This may or may not be valid depending on factors such as production costs, retail price, and the size of the market relative to the supply of service.

Since CCUS is a niche activity today, with generally only small output relative to the markets it is serving, it is generally reasonable to assume that implementation of a new CCUS activity does not affect market demand.

Static versus dynamic baselines

Baseline GHG emissions may change over time due to factors such as technological change and market dynamics. A static baseline is one that uses only a single GHG emission estimate to project a baseline over time (e.g., historical emissions), whereas a dynamic baseline involves periodic updates – usually each year – according to changes or innovations occurring in the market in which the product or service is being provided. For example, year-to-year changes in the generation mix supplying electricity to a grid that can result in changes in the grid emission factor used to calculate baseline emissions.

Changes in baseline emissions are typically only a concern for *ex post* monitoring of project or product performance, rather than for making *ex ante* GHG assessments.

These guidelines include monitoring methods that can account for changes in baseline emissions over time for different parts of a CCUS process chain.

4.5 GHG accounting

The steps, procedures and methods employed to accurately, consistently and transparently identify, select, measure and assess project or product and baseline GHG emissions can be termed *GHG accounting*.

Based on the concepts outlined, key features of the GHG accounting and GHG assessment approach set out in these guidelines are:

- ❑ **Assessment boundaries:** the emissions sources that must be included and counted in the project/product activity and baseline GHG emissions inventory. The boundaries can be tailored to fit to different CCU and CCS configurations;
- ❑ **Baseline scenario / reference case(s):** the relevant counterfactual baseline scenario and reference product and related baseline emissions against which to compare CCUS project and product GHG activity emissions. Methods can be readily applied using existing approaches so that relative GHG emissions reduction and benefits (or otherwise) can be assessed for given technology configurations;
- ❑ **Assessment and evaluation:** emissions and emissions reduction estimates can be made *ex ante* using a range of assumptions about technical design of the project or product in order that the GHG effects of an activity/product can be assessed prior to its implementation;
- ❑ **Monitoring:** this involves collecting data on each emission source within the project boundary and compiling a GHG inventory for the CCUS project and baseline after its implementation (i.e., *ex post*). Methodologies for estimating and monitoring relevant emissions are straightforward to construct based on existing experiences under, for example, the UN Kyoto Protocol's clean development mechanism (CDM) and voluntary carbon offset schemes;
- ❑ **Universal and standalone application:** rather than relying on policy measures to determine an acceptable level of emissions or a level of emissions reduction required, project- and project-based approaches allow an assessment of GHG effects to be calculated in a robust and transparent way and reported to all stakeholders where policy is locally absent.

Application of these guidelines relies on users to select appropriate assessment boundaries, assess and select relevant baseline scenarios, collect data to estimate *ex ante* emissions and emissions reduction and to design monitoring schemes to collect relevant data following implementation. Guidance is provided in these contexts throughout.

5 GUIDANCE FOR USE

5.1 Defining a GHG assessment goal

The first consideration when starting a GHG assessment of CCUS technologies is to consider, understand and define the overall goal or objective of the assessment.

- ❑ **When applying these guidelines, the primary goal should be to establish a complete, transparent and consistent measure of the GHG effects (emissions reduction or otherwise) of an entire CCUS project or product process chain.** These guidelines provide both a full chain project- or product-based approach to calculating net GHG effects of implementing CCUS technologies. However, while this is the primary purpose, other circumstances and interests may affect the GHG accounting approach adopted by the user.

- ❑ **A secondary goal may be the appraisal of policies which promote alternative technologies at a national or organisation level.** An organisation may wish to understand the relative GHG effects of its CO₂-derived product compared to a conventional product but consider that GHG effects outside its operational control should not be included. Alternatively, an assessor may wish to understand potential emissions reduction benefits of introducing CCUS technologies at a national level. For example, in assessing the potential impacts and benefits of a programme or policy focussed on CCUS technologies.

In either situation, the assessment boundary must be modified to reflect the components of the CCUS process chain that lie outside of operational control or national boundaries of the assessing entity. Examples include import of fuel and/or export of products. Where modifications to the assessment boundary are made, these should be clearly stated, and reasons given for the omissions.

These guidelines can accommodate such approaches if required, although it should be noted that such assessments may provide an incomplete and therefore uncertain measure of the full range of GHG effects attributable to a CCUS activity. The uncounted GHG effects should therefore be estimated and listed as a memo item to the calculated result of the GHG assessment.

- ❑ **A third goal may be the assessment of emerging new technologies at or below TRL 5.** These guidelines have not been designed to support early-stage technology assessments. The basic principles set out herein may, however, be of use in supporting this type of assessment.

Users following these guidelines shall clearly state the goal of their GHG assessment in the documented results.

5.1.1 Project- or product-based assessment

A further consideration for the assessment goal is the unit of assessment.

- ❑ **Project-based approaches** typically involve an assessment of GHG effects based of the absolute emissions arising across an entire project system, calculated by comparing the whole system GHG inventory over a fixed time period, usually one year, with that of the

comparable baseline system over the same period. The calculation can also be scaled-up to cover multiple years.

- ❑ **Product-based approaches** usually involve an assessment of GHG effects on a unitised or normalised basis per system function or output. This is calculated by comparing the GHG emissions associated with delivering one system function or output (GHG intensity) with that of a supplying an equivalent function or output using an alternative method. Such assessments must use the same functional units to make a per unit estimate. The choice of functional unit is a critical consideration when making this type of GHG assessment.

A switch between project and product GHG inventory and assessment can be readily made by using the entire system output over a given period of time to generate an absolute GHG emission, and vice versa, as described below.

5.2 GHG effects from CCUS

Technologies involving CCUS pose some specific complexities when trying to measure and account for GHG effects. Two key issues are:

- ❑ **C-stock transfers.** The primary GHG effect involves carbon ‘stock transfers’, where carbon in the form of CO₂ that would be otherwise emitted into the atmospheric carbon pool is instead transferred to a different carbon pool: either into products or the geological carbon pool.
- ❑ **System multifunctionality:** The capture and transfer of carbon creates multiple GHG effects in respect of substituting products and services provided in different markets both up- and downstream of the point of CO₂ use or storage. These can be difficult to identify and characterise.

These characteristics in combination mean that the GHG effects arising from CCUS process chains can be multiple and separated in both space and time; in other words, CCUS creates both geographical and temporal accounting challenges.

These guidelines take account of these effects by setting out guidance on appropriate choices for the assessment boundary for various CCUS technologies.

GHG effects arising from the substitution of products and services across CCUS process chains include up- and downstream effects.

5.2.1 Upstream (supply) side GHG effects

Emissions reduction can result from the capture of CO₂ and the avoidance of its emission to the atmosphere during the provision of an emission intensive service (e.g., power generation) or product (e.g., industrial process such as cement making). Isolating the CO₂ from the atmosphere through storage in products or in geological reservoirs leads to an emissions reduction relative to alternatives methods of providing the same service without CO₂ capture (assuming that is the relevant baseline scenario).

The size of the GHG effect is also partly dependent on the CO₂ retention time – or permanence – of storage.

Capturing CO₂, either from flue gases or directly from the air, involves the use of additional energy in the facility compared to a standard configuration, which creates negative GHG effects due to additional fuel consumption or the de-rating of the plant (in power generation facilities) – effects referred to as the ‘energy penalty’. Therefore, the amount of CO₂ *captured* does not directly equate to the amount of CO₂ emissions *avoided*, which must be taken account of in the GHG assessment.

5.2.2 Downstream (demand) side

CO₂-derived products may have a different GHG intensity in fabrication and use relative to incumbent, conventionally-derived, products. Displacement and substitution of the incumbent by the CO₂-derived product can therefore create GHG effects, which may be negligible, positive or negative depending on circumstances.

Downstream GHG effects from CCU activities must be set in relation to the CO₂ supply side effect of CO₂ capture, which in combination may produce an overall net positive GHG effect across the process chain, even if downstream effects are negative.

Adequately accounting for these GHG effects relies on selecting an appropriate assessment boundary in respect of whether all GHG effects are fully included in the assessment, and the use of an appropriate baseline scenario and methods for calculating baseline emissions (or reference case(s)). Care also needs to be taken to avoid double counting the GHG effects.

Addressing these characteristics is a key feature in the design of these accounting guidelines.

One-time GHG effects are not covered in these guidelines.

5.2.3 Assessment boundaries

The following characteristics must be recognised when selecting an assessment boundary for GHG assessments of CCUS:

- ❑ **Spatial.** Movement of carbon molecules between different entities and operators, and into different process and product streams, with the attendant risk that CO₂ is re-released back to the atmosphere farther down the chain and are not appropriately accounted for within the GHG assessment (sometimes referred to as *leakage effects*). The physical movement of CO₂ molecules can also pose the risk of double-counting emissions reduction effects;
- ❑ **Temporal.** Prolonged or indefinite retention of carbon or CO₂ molecules away from the atmosphere in either geological reservoirs or in finished CO₂-derived products. In either case there is the potential risk of intentional or unintentional release of the carbon back to the atmosphere at some future point in time outside of the temporal boundaries of the GHG assessment framework (*permanence* or *CO₂-retention* and *carbon reversal risk*).

Avoiding leakage risk requires use of spatial assessment boundaries that include all relevant GHG emission stocks and sources in the GHG assessment, albeit subject to the particular goal of the GHG assessment as described above (Section 5.1).

Avoiding carbon reversal risk requires different approaches depending on CCUS technology.

In the case of CCU, product-based GHG accounting standards such as BSI: PAS 2050 (BSI, 2011) require users to account for all GHG emissions arising from product fabrication, use and disposal over a 100-year time frame. A 100-year timeframe is considered to be a valid approach in these guidelines, because the measurement of GHG effects implicitly assumes that CO₂-derived products substitute and displace functionally-equivalent conventional products. Consequently, this also leads to the assumption that use and disposal of the conventional product would generate the same emissions as use and disposal of the CO₂-derived product, resulting in a net zero GHG effect (i.e., the emissions from this life cycle phase cancel each other out across the project/product and baseline scenario).

In contrast, accounting standards and regulations for CCS generally require assurances to be provided regarding permanent storage over much longer periods (e.g., >1000 years). This is also considered to be a valid approach in these guidelines, because unlike CCU, there are no downstream GHG effects associated with product substitution. Assurances over permanence are typically achieved by setting standards or regulations for, *inter alia*, storage site selection, management and allocation of responsibility to remedy any seepage of CO₂ out of the storage site.

For CCU, the guidelines propose that users apply a hybrid assessment boundary approach that includes emissions from product use – and, to an extent, end-of-life – even where cradle-to-gate assessments are used for CCU GHG assessments (see Box 5.1). This allows for a fuller picture of downstream GHG effects to be developed, and ultimately enhances the transparency of GHG assessments for CCU technologies.

Further detail on setting assessments boundaries for different components of a CCUS chain is provided in individual modules below.

5.2.4 Baselines and multifunctionality

CCUS process chains have the potential to produce multiple system outputs or products including:

- ❑ **Primary “P1” product or service:** a CO₂-derived product (intermediate or final) or the provision of a geological CO₂ storage service;¹
- ❑ **Secondary “P2” product or service:** the product or service delivered by the facility from which the CO₂ was captured (e.g., electricity or industrial production process);² and,
- ❑ **CO₂ product:** the captured CO₂ may sometimes be considered as a product where it is input into a CCU process chain;

For these reasons, LCA practitioners refer to such systems as being *multifunctional* (UNEP, 2008; UNEP, 2011; von der Assen, 2015).

¹ Terms primary and secondary product were introduced in IEA GHG, 2018, and have been kept consistent in these guidelines.

² Except in the case where CO₂ is provided using direct air capture, which does not produce any other product other than the CO₂ product – in other words, it is mono-functional (von der Assen, 2015).

For CCS process chains, only the secondary P2 product is of relevance. This means that only one set of baseline scenarios and one estimate of baseline emissions is required for a GHG assessment.

For CCU process chains, all three products are relevant to determining the baseline scenario and baseline emissions. Consequently, system multifunctionality means that GHG assessments for CCU need to consider and resolve two key functions in the GHG accounting method:

- ❑ **Multiple baselines.** Use of more than one baseline scenario and baseline emissions for different parts of the system; and,
- ❑ **System interdependence.** The need to account for the interdependence of system components across the chain based on the rate at which one output or product is moderated relative to another (i.e., each system product is generated at different rates according to different CCU process chain configurations).

Handling system *multifunctionality* and both supply and demand side GHG effects is a critical factor in the design of effective GHG accounting systems for CCU process chains. Methodologies must consider the GHG effects arising from the supply of all three products.

Accounting solutions for multifunctionality rely on assumptions around functional equivalence and substitution and the choice of functional unit used in the analysis.

Methods to account for this factor are a key part of these guidelines.

5.2.5 Functional equivalence and substitution

As noted above (Section 4.4.2), functional equivalence is an important factor for determining the baseline scenario and calculating baseline GHG emissions. For CCUS systems, the following two factors are critical to determining baseline emissions:

- ❑ **Quantum or substitution rate.** The rate at which system outputs substitute the conventionally derived product (see *Equivalence of products and services* above); and,
- ❑ **Source or type of product or service.** The type of product or service that is assumed to be substituted by the new project or product. This requires careful choices when identifying and selecting appropriate baseline scenarios that include technologies relevant to the given market and jurisdiction.

Variations in assumptions around either or both these factors can lead to wide variations in the estimated baseline emissions, and therefore the calculated emissions reduction potentially achievable by CCUS.

Quantum / substitution rate

In general, the quantum of secondary P2 product or service from the facility from where CO₂ is captured tends to be functionally-equivalent because the underlying process and output does not change between the CCUS and baseline scenario, only the fact that CO₂ is captured and utilised in the former. Consequently, the quantum of product substituted – or the substitution rate – between the project and the baseline scenario can be assumed to be 1:1 i.e., 1 MWh of electricity from the facility where CO₂ is captured is fully interchangeable with 1 MWh from another source of electricity assumed in the baseline scenario.

The guidelines use a ‘CO₂ capture benefit’ method to handle the supply-side, upstream, aspects of multifunctionality associated with the CO₂ product and the secondary P2 product. The method isolates the upstream element of the comparative assessment (i.e., between the CCUS scenario and baseline scenario), into a single unit which can be factored into GHG assessment.

The CO₂ capture benefit method essentially calculates the quantum of emissions reduction embedded into each tCO₂ that is captured and sent for utilisation or storage, according to assumptions around source of CO₂ and the baseline scenario for delivering the same secondary P2 product or service. It also includes any emissions arising from CO₂ transport that could occur upstream of the point of CO₂ use or storage.

This results in separate handling of the up-and downstream GHG effects occurring in CCUS process chains either side of the boundary of the utilisation or storage facility. It is considered to offer several benefits relative to compiling a whole system analysis:

- ❑ It improves the transparency of accounting methods by handling the GHG effect of CO₂ capture separately and independently of the utilisation/storage that could occur in any particular CCUS process chain downstream of capture and transport;
- ❑ It reduces the complexity of comparative accounting methods by reducing the inherent benefit of capturing CO₂ into a single data point, which is particularly beneficial for CCU GHG assessments;
- ❑ It allows for a direct comparison to be made between alternative CCU fabrication methods without including the additional complexities of considering CO₂ capture each time, which can be added afterwards according to the inherent benefit assumed to be present in the captured CO₂ (according to the ‘CO₂ capture benefit factor’). This also allows for benefits to be systematically analysed independent of product type, thereby allowing comparisons to be more readily made across a range of products;
- ❑ It provides insights into issues around impermanence and carbon reversal risk by providing an indication of the residual GHG *liabilities* associated with each tCO₂ that could be re-emitted.¹
- ❑ It reduces the methodological burden on users since the CO₂ capture benefit can be determined for a fixed set of project and baseline scenario assumptions, as set out Annex A. Without the use of such a factor, it is necessary to perform a *systems expansion* for every assessment, requiring the collection of emissions for both the CO₂ source facility and baseline facility for each and every GHG assessment.
- ❑ It allows an assessment to be made of the potential range of overall product GHG emission reduction benefits in situations where there is incomplete knowledge about the source of CO₂ and the possible range of baseline scenarios.

It is also generally reasonable to assume that most CCU process chains result in primary P1 products that are directly interchangeable with conventionally-produced incumbent

¹ The residual liability for such emissions is broadly equivalent to the reciprocal of the CO₂ capture benefit factor, assuming all other downstream sources of emissions are equal for both P1 CCU and reference cases.

counterparts; in other words, the products on the demand side of a CCU system are functionally equivalent.

This means that perfect substitution by primary P1 system outputs can be applied (i.e., a functional unit of CO₂-derived product provided in the new activity can usually be assumed to substitute the same product in the baseline scenario on a 1:1 basis).

Box 5.1 Relevance of assessment boundaries to functional equivalence and units

Cradle-to-gate analyses employ an assessment boundary that ends at the gate of the P1 product fabrication facility, and does not account for possible whole-life downstream GHG effects arising from product use and disposal. This approach can lend itself to annualised GHG accounting cycles that are typical of GHG policies and incentive schemes.

Cradle-to-grave assessments employ an assessment boundary covering the whole life of a product, and therefore potentially require a more holistic assessment of secondary GHG effects because of the downstream performance of the final product over its entire life-span. These approaches are more aligned with life cycle analysis (LCA) methods and product-based policies and incentives.

Some uncertainty persists over whether there is a need for cradle-to-grave analysis in CCU GHG assessments. This is because it is generally reasonable to assume a baseline scenario where a product or service is displaced by the new functionally-equivalent CO₂-derived product on a 1:1 basis. Consequently, emissions occurring in use and disposal downstream of the factory gate should in principle be the same under both scenarios, and therefore cancel each other out as described above.

In the case of CO₂-derived methanol, for example, a cradle-to-gate GHG assessment that assumes 1:1 substitution of a conventionally-derived methanol product can be acceptable. Methanol can also be used as an *intermediate* product and can therefore potentially enter a range of possible secondary processing and end use pathways, which may be unknown or uncertain for the assessor. However, the same potential exists for an alternative, conventionally-produced methanol, and thus this indicates that cradle-to-gate assessment is acceptable.

On the other hand, taking a cradle-to-grave approach to assessing methanol based on a final product poses some uncertainties regarding the baseline and choice of functional unit. If, for example, the functional unit of the assessment is not the mass or volume of methanol but some other secondary product such as petroleum (i.e., in the case of using methanol as a petroleum substitute for blending), a different approach may be needed. The lower calorific value of methanol means the substitution rate in petroleum blending is somewhere around 1.95:1 based on its relatively lower calorific value. Thus, it is not functionally equivalent. These guidelines may not be readily applicable to situations where the choice of functional unit is a final product derived from a CO₂-based intermediate product, rather the CO₂-derived product per se, as described further below (Section 7.3).

In some cases, CCU technologies can lead to other types of performance changes in respect of the final product, which has implications for the fabrication process. For example, CO₂ cured concrete is reportedly stronger than conventionally cured concrete, leading to material gains during fabrication and, ultimately, in use. These guidelines suggest methods by which these gains may be accounted for.

Perfect substitution may not always be the case, however, and the substitution rate of the primary P1 product may be different due to different properties of the CO₂-derived product. For example, CO₂ cured concrete is reported to have higher strength than conventional concrete, meaning fewer functional units of product are required compared to conventional incumbents, which reduces material consumption in respect of cement and other process inputs such as water consumption and road transport journeys (for delivery of wet mix cements).¹ This can enhance secondary GHG effects. Conversely, other CO₂-derived products, for example, methanol, can reduce efficiency when substituted on a 1:1, depending on choice of functional unit and boundary (Box 5.1).

The choice of assessment boundaries can also be a feature when considering the quantum of alternative primary P1 product that is substituted (Box 5.1).

Source / type of product or service

The source of the product assumed in the baseline scenario can have profound impacts on the estimate of baseline emissions, even where perfect substitution is assumed. The market into which CO₂-derived products enter vary from region to region; some CO₂-derived product markets are highly localised – for example, construction aggregates (because of the cost of bulk transport) – whereas others tend to be regional markets (e.g., methanol) or global (e.g., fuels). Care is therefore needed in selecting the incumbent conventional product type that is assumed to be substituted when establishing the relevant baseline scenario.

Different markets will have different supply bases, and therefore varying sources of conventional product which may or may not be more GHG intensive than other sources. For example, coal-derived methanol (e.g., from an integrated gasification plant in, for example, China) will likely be more GHG intensive to produce one functional unit compared to a functionally equivalent product derived from steam-methane reforming of natural gas, for example, in Europe. Thus, assuming substitution and displacement of the former will have a greater GHG effect than substituting the latter.

In reality, specific markets are typically made up of supplies from a range of sources, particularly for products that are traded regionally or globally. This has ramifications for the choice of baseline scenario product – and the related GHG intensity – that is assumed to be substituted in the analysis. The intermediate nature of the products derived from different CCU processes also means that there are a number of competing conventional products that can potentially provide the same function or service as the CO₂-derived product. For example:

- CO₂-derived aggregates could substitute conventional primary (hard rock or gravel) or secondary (recycled) aggregates;
- CO₂-derived methanol could substitute methanol derived from natural gas or coal, or be used to substitute petroleum products through fuel blending; and/or
- Algal-derived ethanol and crude oil produced by CO₂-enhanced oil recovery (EOR) could substitute a wider range of oil-based products (e.g., petroleum or diesel derived from conventional crude oil, oil sands crude, synthetic crude or bio-based fuels).

¹ See for example: www.solidiatech.com and www.carboncure.com

It is therefore possible that a range of different products with different GHG intensities could be substituted by a CO₂-derived product in any given market.

The complexity of market supply bases also mean that assumptions can vary depending on which segment of the market or supply source might be displaced by a CO₂-derived product. For example, a CO₂-derived product could displace the *marginal* product in a given market, or it could displace the *average* product. Substituting the marginal product – which may be the most expensive and potentially the most GHG intensive – can have different GHG effects compared with substituting a less GHG intensive average market product. For example, Venezuelan heavy crude oil is typically more GHG intensive to produce than, for example, a Saudi Arabian light crude with a relatively low GHG intensity.

Assuming that a CO₂-derived algal fuel displaces heavy crude will show higher relative GHG effects than assuming displacement of the market average crude oil, with a GHG intensity made up from a diversity of supply sources. This factor will also vary from market to market according to the typical supply base in that market.

Users of these guidelines should take care to ensure appropriate choices are made in selecting the baseline scenario, and, in particular, the primary P1 product that is used to calculate baseline emissions in CCU assessments.

Clear explanations of the rationale underlying choices made should be provided, based on aspects such as market analysis and supplier assessments.

Functional units

Functional units are a relevant consideration for intensity-based (normalised or unitised) GHG assessments as typically applied in product-based accounting approaches (Section 5.1.1). Typical metrics that could be used in intensity based GHG assessments include:

- GHG emissions.** tCO₂-equivalent (tCO₂e) emissions per functional unit output
- GHG effects.** tCO₂e emissions *avoided* per functional unit output (comparative assessment)

Because CCUS systems can have multiple functions and outputs, choices are presented regarding the use of functional units of primary P1 product, CO₂ product or the secondary P2 product (measured in mass, volume or energy content of a system output).

In applying these guidelines, the recommended functional unit is the primary P1 product, although this differs between CCS and CCU.

For CCS, the functional unit is always tCO₂e avoided per unit of storage provided (i.e., tCO₂e avoided/tCO₂e stored). This is, in essence, the same result as calculated by the CO₂ capture benefit method minus any emissions from CO₂ injection and storage, which are usually negligible.

For CCU, the functional unit is also the primary P1 (CO₂-derived) product, but measured in either mass, volume or energy content (i.e., tCO₂e avoided/unit of P1 product, usually mass).

The differing measures of functionality mean that the approach does not readily allow for comparisons between CCU and CCS technologies. It is possible to adopt a different functional

unit, such as units of secondary P2 product or CO₂ product, to support such comparisons, although the value of such an approach needs to be considered with some caution. The example below illustrates why:

Assuming a CO₂ capture benefit factor of 0.6 i.e., that 0.6 tCO₂e emissions are avoided (av) for each tCO₂ that is captured (cap), the calculated GHG effect of CO₂ capture can be calculated as 0.6 tCO₂e av/tCO₂e cap. This could be the approximate case for CO₂ capture on a natural gas plant compared to the same plant without capture.

- ❑ In the case that the captured CO₂ is part of a CCS process chain, if no emissions occur downstream during CO₂ injection and storage, the tCO₂e av/tCO₂e stored = 0.6
- ❑ In the case that the captured CO₂ is part of a CCU chain, emissions downstream from the fabrication, use and disposal of the P1 CO₂-derived product could be any of the following levels relative the relevant conventional P1 product that is assumed to be displaced:
 - a) *equal*, resulting in a GHG mitigation effect the same as the CCS case (i.e., tCO₂e av/tCO₂e utilised = 0.6)
 - b) *lower*, resulting in a positive GHG mitigation effect relative to the CCS case (i.e., tCO₂e av/tCO₂e utilised > 0.6)
 - c) *higher*, resulting in a mitigation effect that is negative relative to the CCS case (i.e., tCO₂e av/tCO₂e utilised < 0.6)

In all cases, the baseline or benchmark inherently becomes the CCS case.

In the final CCU case (c), however, although the GHG effects appear worse than the CCS case, there may still be an emission reduction benefit when compared to a conventional product. For example, the calculated tCO₂e av/tCO₂e utilised could be 0.4, while the tCO₂e av/t P1 product may be 0.7. So even if the GHG effect is not as great as for CCS, there is not necessarily a strong case for doing CCS instead of CCU because it really depends on the choice of functional unit. This in turn determines the benchmark or baseline for evaluating the GHG effects of the technology.

Therefore, it is recommended that the primary P1 product is always used as the functional unit for any CCUS GHG assessment, even if it hampers comparisons.

System interdependence

The choice of functional unit also has repercussions for the handling of system multifunctionality in respect of how the GHG assessment moderates one system output by the output of another system function (Section 5.2.4). This is more of an issue for CCU than CCS, because generally the rate of CO₂ injection (P1 service) is the same as the rate of CO₂ capture, less any emissions from CO₂ transport and injection.

Where a GHG assessment of a CCU technology uses the functional unit of primary P1 (CO₂-derived) product, the calculated rate of other system outputs (secondary P2 product and CO₂ product) are governed by the rate at which P1 product fabrication consumes CO₂. For example, if a CCU process requires 1 tCO₂ to produce 1 tonne of primary P1 product, and 0.6 MWh of electricity are produced for each tonne of CO₂ captured for utilisation, then the quantity of P2 used to calculate both activity and baseline emissions must be 0.6 MWh. If the CCU product

requires 2 tCO₂ to produce 1 tonne of P1 product, then the quantity of P2 output would be 1.2 MWh per tonne primary P1 output etc.

System *interdependence* is effectively handled in these guidelines by using the CO₂ benefit factor method. The method results in a GHG emissions reduction ‘factor’ that can be applied to each tCO₂ consumed in the fabrication of the primary P1 (CO₂-derived) product. The same principle can be applied to CCS assuming the primary P1 service is CO₂ storage, as described further below.

5.2.6 Double counting

The multifunctional nature of CCS systems, with multiple GHG abatement effects occurring both up- and downstream, poses the risk of double counting GHG effects. Double counting can occur when different users take a different perspective for a GHG assessment. For example, the entity capturing the CO₂ may take only an upstream perspective, while the entity producing a CO₂-derived product may adopt only a downstream view.

These contrasting perspectives can lead to double counting: the former is likely to consider that an emissions reduction occurs at their facility as a result of CO₂ capture, and count the emissions reduction as such. The latter could take the view that any fugitive emissions of captured CO₂, and/or CO₂ emissions arising from the use and disposal of their product should not be counted as a fossil CO₂ emission source because it is captured CO₂ that would be otherwise emitted to the atmosphere absent of their CCU activity. In other words, both entities may count the emissions reduction occurring from CO₂ capture.

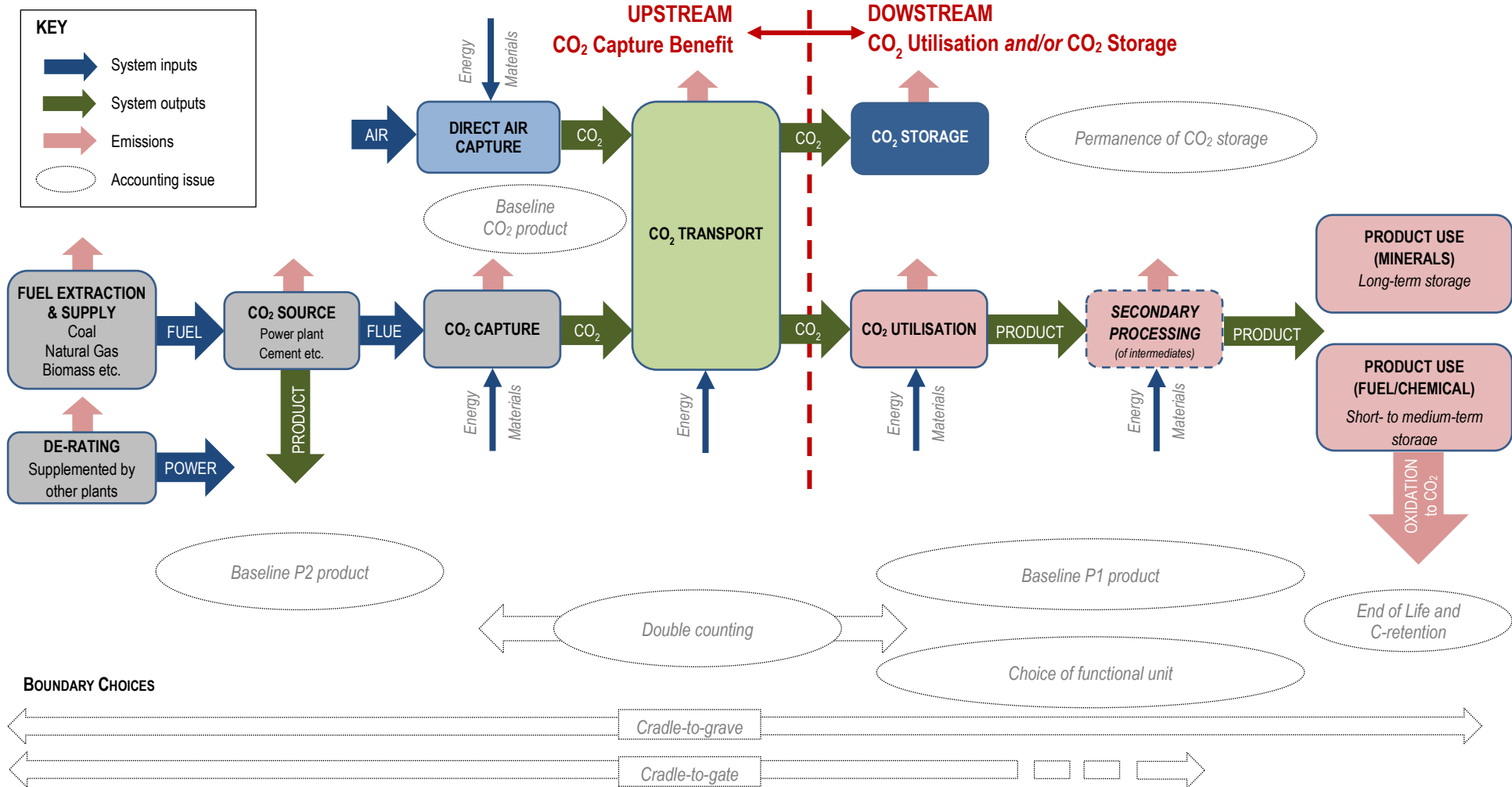
Both perspectives are, to a degree, appropriate. However, from an accounting perspective the emission reduction effect of capturing CO₂ can only be counted once, either upstream by the CO₂ capturing entity or downstream by entity using the CO₂, but not by both. So, if CO₂ capture is counted as an emission reduction at source, its re-emission must be counted as an emission. If CO₂ capture is not counted as an emission reduction at source, then it can be counted as a zero-emission if re-released to the atmosphere during product transport, fabrication, product use and disposal.

The CO₂ capture benefit approach set out in these guidelines assumes that CO₂ capture is an emission reduction at source, and therefore counts the emission reduction at the point of CO₂ capture (including transport). Consequently, any re-release of captured CO₂ *downstream* of the point of utilisation or storage *must* be counted as an emission. The only exception to this is where the CO₂ is captured from biological sources, which may be zero-rated for emissions purposes.

Re-release of CO₂ captured directly from the air must be counted as an emission if it was counted as a CO₂ removal upon capture.

A summary of the main issues for GHG accounting across a CCUS process chain are shown schematically below (Figure 5.1).

Figure 5.1 Schematic overview of CCUS system components, accounting concepts and issues



Source: Authors

5.3 Basic accounting method

Based on all the above, this section presents the accounting formula that should be employed by guideline users. The basic formula presented here is supplemented by specific guidelines and methods for each phase of a CCUS activity, which are outlined in separate modules below.

5.3.1 Formula

Project- and product-based approaches involve calculating the GHG emissions that occur within the defined assessment boundary of a project activity over a given period of time (i.e., a project and/or product GHG inventory) and comparing this with the GHG emissions associated with providing the equivalent level of goods or service under the most appropriate alternative baseline scenario involving different technologies. A time period of one calendar year is usually assumed, but a whole life assessment may also use the entire lifespan of the activity. The difference in GHG emissions between the two scenarios provides an estimate of emissions reduction (Figure 4.1). The basic accounting formula is thus:

$$ER_t = BE_t - PE_t$$

[Equation 1]

Where,

<i>ER</i>	=	<i>Emissions reduction (tCO₂e reduced or tCO₂e per functional unit)</i>
<i>BE</i>	=	<i>Baseline emissions (tCO₂e emitted or tCO₂e per functional unit)</i>
<i>PE</i>	=	<i>Project or product activity emissions (tCO₂e emitted or tCO₂e per functional unit)</i>
<i>t</i>	=	<i>Time period of assessment</i>

Project-based approaches often require any significant downstream secondary GHG effects to also be identified and counted as leakage emissions in circumstances where they occur outside of the project boundary, for example, as under the CDM. Such Leakage Emissions (LE) would be added to Project Emissions (PE) in the above equation.

In these guidelines, secondary GHG effects are handled as a key part of the overall GHG assessment, and therefore users are not required to take account of leakage. Rather, users must identify and apply comprehensive assessment boundaries that count all significant and relevant GHG emission sources in both the project and baseline scenario.

Exclusions do apply, as described below (Section 5.3.7).

The accounting approach employed in these guidelines means the method presented in Equation 1 is modified for the following two reasons:

- ❑ **The use of the CO₂ capture benefit factor method.** This isolates and packages upstream GHG effects and separates these from downstream GHG effects (Figure 5.1). The CO₂ capture benefit factor is used to modify the results of the downstream assessment of GHG effects. This results in the need for a modular formula containing two components;

- ❑ **The need for an evaluation framework relevant to assessing CO₂-derived products.** This means that a product-focussed, GHG intensity-based, emissions reduction result is the first order calculation applied.

The basic formula for calculating GHG effects is thus modified to the following:

$$GHG\ Effect\ \left(\frac{GHG}{ACT_{CCUS}}\right) = BL_{E,i,P1} - PE_{E,i,P1} [= (-C_{CAP,BF} \times USR_{P1,ACT}) + \sum_{s=1}^n E_{i,s,ACT}]$$

[Equation 2]

Where, as Equation 1 plus;

<i>GHG Effect</i>	=	<i>GHG effects or “reductions” created by supply of one functional unit of P1 CCUS product or service</i>
<i>P1</i>	=	<i>Primary P1 product or service (in functional units of analysis)</i>
<i>E</i>	=	<i>Emissions (tCO₂e)</i>
<i>i</i>	=	<i>GHG intensity (tCO₂e emitted per functional unit)</i>
<i>s</i>	=	<i>Sources (s) 1 – n</i>
<i>ACT</i>	=	<i>P1 activity [utilisation or storage of CO₂]</i>
<i>C_{CAP,BF}</i>	=	<i>CO₂ capture benefit factor (tCO₂ per tCO₂ delivered) [from Equation 5]</i>
<i>USR</i>	=	<i>Utilisation or storage rate (tCO₂ per P1 functional unit)</i>

The formula provides an estimate of GHG effects on an intensity basis according the functional unit selected for analysis.

Since the CO₂ capture benefit factor resolves the GHG effects occurring upstream of the utilisation or storage facility in isolation, the baseline (*BL_{E,i,P1}*) in Equation 1 relates only to the downstream emissions and primary P1 product, which varies according to the following:

- ❑ **For CCU assessments.** The GHG emissions intensity of producing a functionally-equivalent primary P1 product in the baseline scenario relevant to the assessment (tCO₂e per functional unit of product). It can be derived from either published studies or calculated by the user;
- ❑ **For CCS assessments.** Zero, because there is no equivalent primary P1 services that are comparable to a CO₂ geological storage activity, other than “storing” CO₂ in the atmosphere (i.e., emissions), which is handled under the P2 product in the CO₂ capture benefit factor. Alternatively, the baseline can be considered similarly to an environmental baseline at the geological storage site location, which is not subject to leaks or CO₂ prior to project implementation i.e., zero emissions.

The utilisation or storage rate (*USR_{P1,ACT}*) in Equation 1 is also variable between CCU and CCS, according to the following:

- ❑ **For CCU assessments.** The rate at which the primary P1 fabrication process utilises CO₂ (tCO₂e per functional unit of product). It varies for different CCU technologies;
- ❑ **For CCS assessments.** One, because the rate of CO₂ injection for storage purposes is generally the same as the rate at which it is supplied from CO₂ capture and transport.

The calculated GHG effects on an intensity basis (from Equation 2) can be readily converted to an absolute or project-based estimate of emission reductions by multiplying the GHG effect by the output of the primary P1 product or service provided over a given time period:

$$ER \left(\frac{tCO_2e}{t} \right) = GHG \text{ effect} \times P1_{ACT,t}$$

[Equation 3]

Where,

<i>ER</i>	=	<i>Emission reduction (tCO₂ per unit of time)</i>
<i>GHG effect</i>	=	<i>GHG effect on a per GHG intensity (per functional unit) basis [from Equation 2]</i>
<i>P1_{ACT}</i>	=	<i>Quantity of CCUS product or service provided (in functional units)</i>
<i>t</i>	=	<i>Selected time period (e.g., 1 year)</i>

5.3.2 Functional units

The choice of functional unit in all cases is critical to the effective application of the formula. They should be either:

- For CCU assessments.** Units of primary P1 product output measured in either mass, volume or energy content. Alternative functional units may be employed where cradle-to-grave assessments are to be carried out.
- For CCS assessments.** Units of primary P1 storage services provided measured in tCO₂ stored.

See Section 5.2.5 for the rationale underlying this approach.

5.3.3 Combined CCU and CCS activities

A consequence of using different functional units is that combined CCU and CCS activities, where captured CO₂ is sent for both utilisation and geological storage from a single source facility, can only be assessed on an absolute, project emissions, basis.¹

In such circumstances, emissions reductions must be first calculated separately for each of the CCU and CCS streams according to Equation 2. Because it involves a common CO₂ capture source, the amount of CO₂ directed to the CCU facility must be differentiated from the amount of CO₂ directed to the CO₂ storage site. Both CO₂ capture streams must equal the total amount of CO₂ captured from the common capture source.

The emission reductions for the case of a combined CCUS project is therefore calculated as follows:

$$ER (CCUS, tCO_2e) = ER (CCU, tCO_2e) + ER (CCS, tCO_2e)$$

[Equation 4]

¹ Separate emission reduction benefit claims can be made in respect of the CCU component and the CCS component. However, per unit GHG performance claims made for combined CCUS projects according to either the CCU product output or the CCS service (i.e., tonnes stored) alone are considered misleading.

Where,

$$\begin{aligned} ER (CCU, tCO_2e) &= \text{Emission reductions from CCU component (tCO}_2\text{e) [from Equation 3]} \\ ER (CCS, tCO_2e) &= \text{Emission reductions from CCS component (tCO}_2\text{e) [from Equation 3]} \end{aligned}$$

5.3.4 Imperfect substitution

The method presented in Equation 2 assumes perfect substitution of products. As noted above, there are some circumstances where this may not occur (Box 5.1). Users wishing to modify the approach in Equation 2 to accommodate such may do so following guidance provided in Section 7.3.2 and Section 7.4.2.

5.3.5 Modules

The remainder of the guidelines are structured around modules for the separate elements of the basic accounting method presented in Equation 2, covering:

1. CO₂ capture and transportation (calculation of the CO₂ capture benefit factor)
2. CO₂ utilisation
3. CO₂ geological storage

Each module provides specific guidance for GHG accounting covering:

- Introduction
- Scope
- Assessment boundary
- Baseline emissions
- Data
- Other relevant issues

Users must include, as a minimum, the CO₂ capture and transport module and one module of either utilisation and/or storage.

Users undertaking a GHG assessment of CO₂-EOR operations are required to apply both the:

- CO₂ utilisation module.** To calculate the emissions from CO₂ recycle and the GHG effects of supplying crude oil derived using CO₂-EOR techniques; and,
- CO₂ storage module.** To apply methods that provide assurances over the permanence of CO₂ injected into operational hydrocarbon reservoirs for the purpose of storage.

Emissions and reductions arising from CO₂ capture and transportation – the CO₂ capture benefit – are first calculated, after which the captured CO₂ may enter different pathways for offsite utilisation or storage. Captive (onsite) CO₂ utilisation or storage is also possible by excluding CO₂ transport emissions in the calculation of the CO₂ capture benefit factor.

GHG effects arising from each step should be calculated separately and then aggregated into a product/service and a project GHG calculation using Equation 2.

5.3.6 Scope

Inclusion or exclusion of a particular GHG emission sources is governed by the choice of assessment boundaries adopted by users when applying each module, and guidance is provided throughout in these respects.

The guidelines focus only on emissions of the gases CO₂ and methane (CH₄), which are considered to be the most relevant to CCUS technologies.

Wider environmental impacts, benefits or dis-benefits associated with CCUS activities – in particular materials consumption and their associated environmental impacts and GHG emissions – are not covered by these guidelines. Methods for LCA and life cycle impact assessment (LCIA) are also therefore not covered. The approach set out in these guidelines may be used to support LCA studies of CCUS, however.

In designing effective policies to support CCU technologies, it will be important to consider a two-stage approach. In the first instance, the environmental impacts of specific technologies will need to be assessed using holistic analytical frameworks such as LCA and LCIA. These types of assessment frameworks can provide assurances to regulators and the wider public regarding the overall environmental gains that could be achieved relative to alternative product pathways. In a second phase, ongoing analysis, measurement and reporting of emissions performance will be required if a carbon price incentive is to be attached to these activities. These guidelines are focussed on the second, while efforts such as those of the Global CO₂ Initiative are focussed on the first (e.g. Zimmerman et al., 2018).

Efforts have been made to ensure widespread applicability to a range of scenarios and technologies, including application of different capture technologies to different emission sources – including direct air capture – several CO₂ utilisation options as well as geological storage. These provisions notwithstanding, it is possible that the guidelines and methods may not be readily applicable to some CCUS configurations. In such cases, users should seek to develop new methods based on the broad building blocks of the approaches presented herein.

Where a specific CCU technology involves the use of hydrogen, and this hydrogen is bought-in rather than manufactured on-site, emissions from its manufacture would fall outside the scope of these guidelines as this would be considered as a process material input.

However, because of the potentially emission-intensive nature of hydrogen production, special attention should be given to its source and included within the boundary by the user where relevant.

About 95% of hydrogen production globally is derived from the reforming of natural gas, with the separated carbon fraction either vented to atmosphere or used to manufacture urea. Where standard hydrogen is used, the user should assess the emissions from its manufacture.

'Blue' hydrogen is manufactured from natural gas but employs CCS to avoid the emission of the separated carbon fraction. Users should describe the source of the blue hydrogen where this is used.

'Green' hydrogen is manufactured through electro-catalytic water splitting. It is electro-intensive, and thus special attention must be given to the source of electricity used in the case of bought-in green hydrogen, and the associated emissions included within the assessment.

The guidelines do not provide methods for calculating uncertainty.

Only limited discussion is made regarding verification, which may be jurisdiction, standard or verifier specific.

5.3.7 Exclusions

Although the guidelines aim to support comprehensive assessments of the GHG effects of CCUS technologies, certain GHG emission sources are not covered within the boundaries and accounting methods described in these guidelines. Excluded emission sources include:

- Emissions from secondary processing of primary CO₂-derived intermediate products into other types of products, for example, use of CO₂-derived methanol as a chemical building block or the use of CO₂-derived polyurethane to make finished products (e.g., foams for furniture making). These require the users to adopt different boundaries and different functional units based on the function performed by the final product, rather than an intermediate (see Box 5.1)
- Emissions associated with other materials input into CCUS processes, for example, feedstocks and catalysts for CCU process chains or drilling materials for CCS process chains.

Emissions from these sources may be included by users wishing to make a full cradle-to-grave life cycle emissions assessment, but no guidance is offered within these guidelines on how to account for these.

5.4 Linkages with other accounting guides and standards

The methodologies set out in these guidelines share commonalities and potential links with a range of emissions accounting documents, rules and standards in place around the world. As noted above (Section 1.2), presently no formal accounting standards exist for CCU, whereas several standards exist for CCS. In designing these standards, the following have been reviewed to help develop content and ensure alignment of the approach with existing systems:

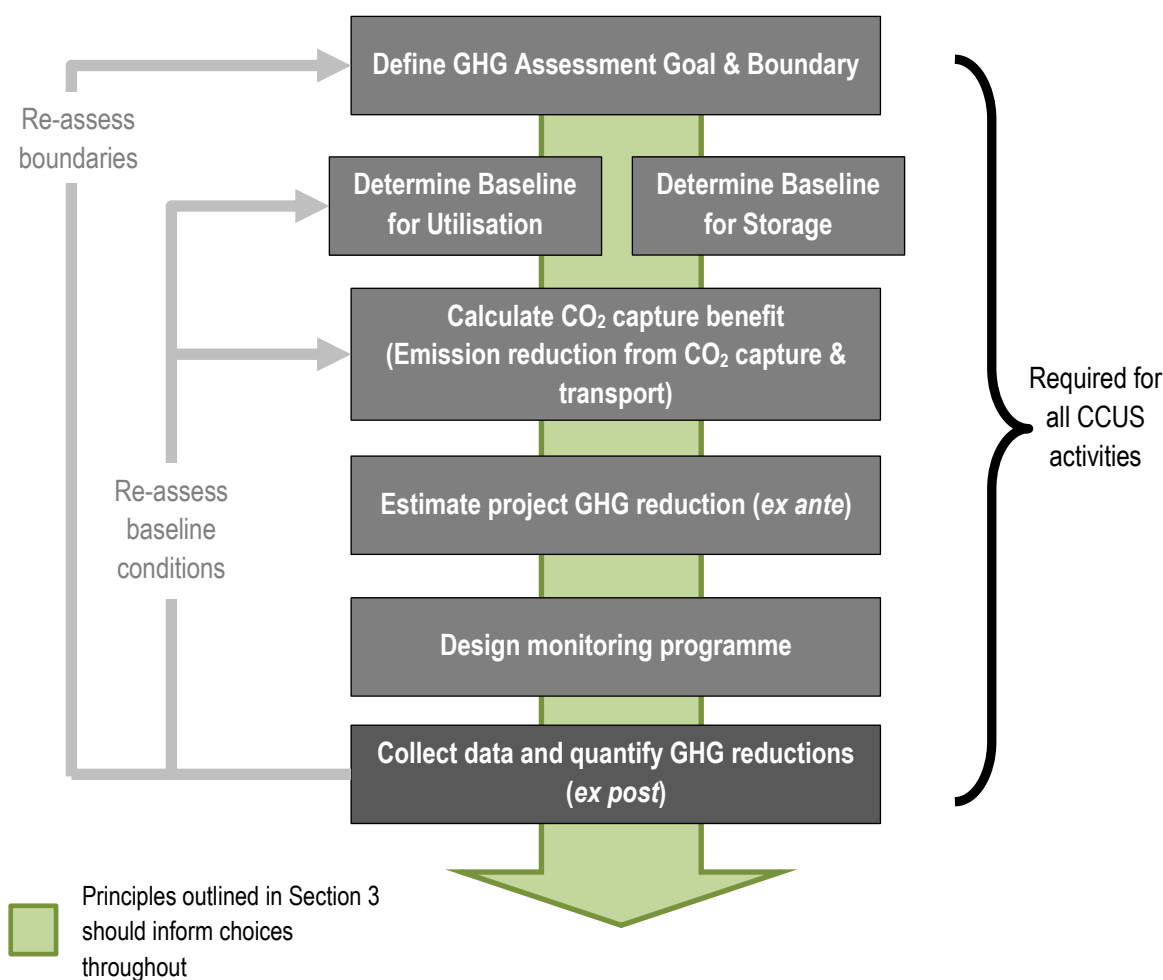
- 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC, 2006);
- Greenhouse Gas Emissions Accounting Guidelines for Carbon Dioxide Capture and Utilisation Technologies v1.0 (IEAGHG, 2018);
- WRI/WBCSD GHG Protocol – The GHG Protocol for Project Accounting (WBCSD/WRI, 2004);
- WRI/WBCSD GHG Protocol – Product Life Cycle Accounting and Reporting Standard (WRI/WBCSD, 2011);
- BSI PAS 2050:2011 Specification for the assessment of the life cycle greenhouse gas emissions of goods and services (BSI, 2011);
- Modalities and procedures for carbon dioxide capture and storage in geological formations as clean development mechanism project activities (Decision 10/CMP.7; UNFCCC, 2011);
- Commission Regulation (EU) No 601/2012 of 21 June 2012 on the monitoring and reporting of greenhouse gas emissions pursuant to Directive 2003/87/EC of the European Parliament

and of the Council Text with EEA relevance (The EU ETS Monitoring and Reporting Regulation or 'MRR');

- ❑ Techno-Economic Assessment & Life Cycle Assessment Guidelines for CO₂ Utilization (Zimmerman et al., 2018).

Since the guidelines adopt a mixed project and product approach, the methods outlined are not applicable to all the regulatory schemes to which the above documents relate. For example, national GHG inventories and the EU's MRR only set inventory and monitoring standards, but not emission reduction calculation methods.

Figure 5.2 Steps for GHG accounting and monitoring



Source: Based on WBCSD/WRI, 2004

6 ACCOUNTING FOR CO₂ CAPTURE AND TRANSPORT

6.1 Introduction

The process of capturing CO₂ either from flue gases or directly from air requires energy for mechanical equipment (blowers, compressors, pumps etc.) and heat for the regeneration of sorbents. These services impose an 'energy penalty' on the facility relative to a facility producing the same product or service but not employing CO₂ capture. The energy penalty poses the need to either increase energy use onsite or to de-rate of the output of the facility due to the increased parasitic load. Further, GHG emissions also arise from incomplete capture of all CO₂ generated at a facility.

Therefore, in terms of GHG assessment, although CO₂ capture reduces point source emissions of GHGs, it still leads to direct emissions and also creates other secondary GHG effects both in- and outside of the facility boundary due to the use of additional energy and/or the supplementing of plant output in the case of de-rating. In either case, the rate of CO₂ generation increases compared to the standard plant, which may or may not be captured. All of this also means that the amount of CO₂ *captured* does not directly equate to the amount of CO₂ emissions *avoided*.

Assessment and measurement of the effectiveness of CO₂ capture to reduce GHG emissions therefore depends on quantifying the emissions from incomplete capture of CO₂ plus the GHG effects arising from the energy penalty and comparing the net GHG emissions from the entire facility with that of the GHG emissions from a baseline scenario.

A further feature of the accounting method established in these guidelines is to isolate up- and downstream GHG effects along CCUS process chains as highlighted above (Figure 5.1). This means that any GHG emissions arising from the transport of CO₂ to the facility utilising or storing it must be quantified and added to the net GHG emissions of the facility.

Approaches to quantifying these emission sources and GHG effects are described in this module, based on using a CO₂ capture benefit method that integrates these accounting elements and allows direct linkage with the CO₂ utilisation and CO₂ storage modules.

6.2 Scope

Methods presented are applicable to CO₂ capture at the following types of facilities:

- Natural gas, biomass or coal fired power plants including:
 - Combined cycle natural gas turbines (NGCC)
 - Integrated gasification combined cycle plants (IGCC)
 - Pulverised coal (PC) and standard, super critical and ultra-supercritical boilers
- Industrial plants:
 - Ammonia production plants
 - Cement kilns
 - Iron and steel mills
- Direct air capture (DAC)

The GHG effects arising from application of most types of CO₂ capture technology can be measured, because the method relies on understanding net emissions rather than specific energy requirements for specific capture technologies.

Methods are included to account for incomplete CO₂ capture and GHG effects arising from the energy penalty either due to additional fuel extraction or the derating of a power plant.

Methods presented are applicable to CO₂ transportation using the following modes:

- CO₂ pipelines
- CO₂ road, rail or ship tanker

Methods presented account for emissions of both CO₂ and CH₄ within the assessment boundary.

6.3 Assessment boundary

The following emissions sources should be included in the assessment boundary for CO₂ capture and transportation:

1. **Combustion and fugitive emissions associated with fuel extraction or harvesting occurring upstream of the source(s) from where CO₂ is captured.** Emissions sources include, *inter alia*, combustion emissions from machinery involved in the extracting of coal; fugitive emissions of CH₄ from mining or natural gas extraction, handling and transport; and, combustion emissions from harvesting machinery and emission from fertilizer in the case of biogenic CO₂. Inclusion of these sources ensures that full consideration is made of emissions resulting from the energy penalty associated with CO₂ capture relative to an unabated facility providing the same output or service.
2. **Combustion emissions from power plants needed to supplement a reduction in power output due to derating of the power plant.** Derating of a grid connected power plant requires supplementary production from other parts of the power grid system to make-up the reduced power output of the facility, with associated GHG emissions.
3. **Combustion emissions from stacks and other point sources across the entire facility where CO₂ capture has been installed.** Emissions sources include stack emissions from incomplete capture of CO₂ or only partial application at a facility (e.g., on single unit).
4. **Fugitive emissions from losses of containment of GHGs during transport.** Emissions can arise from leaks of CO₂ after its capture across the capture and transport system (e.g., pipeline leaks, loading and unloading losses).
5. **Combustion emissions associated with bought-in heat and power.** Indirect or “Scope 2” emissions can arise from the generation of electricity or heat used by the project that occur outside of the facility boundaries but are directly attributable to the activity. Sources include grid electricity and imports of heat from neighbouring facilities for either the capture or transport of CO₂.
6. **Combustion emissions from mobile sources.** Emissions from combustion of fuel used for the propulsion of CO₂ transport vessels.

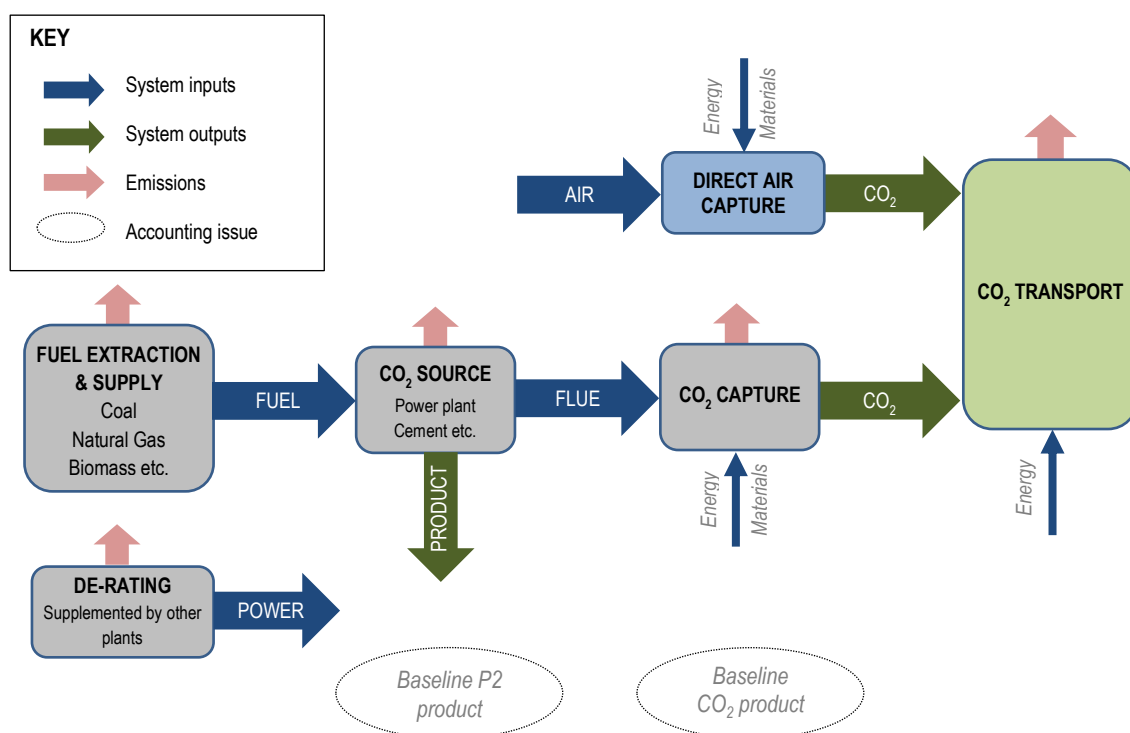
In the case that capacity is added to an existing facility, then emissions from source (1) above must be counted. Alternatively, if the facility will be de-rated through retrofit of CO₂ capture equipment, source (2) above must be counted.

See also Section 5.1 in respect the GHG assessment goal and the choice of assessment boundary.

Embodied emissions associated with bought-in materials used in the baseline and activity (capture and transport) process fall outside of the assessment boundary applied in these guidelines and should therefore not be included as an emissions source nor counted as emissions. These sources are excluded because they are challenging to quantify and positive and negative GHG effects associated with these sources cannot easily be attributed to the activity nor its owners/operators.

The key boundary and accounting choices are shown schematically below (Figure 6.1).

Figure 6.1 Schematic overview of CO₂ capture system components



Source: Authors

6.4 Calculation of GHG effects

GHG effects arising from CO₂ capture are based on measuring the GHG emissions from a facility fitted with CO₂ capture to that of a selected baseline facility providing a functionally equivalent secondary P2 product or service.

The result of the assessment is expressed as tCO₂e *avoided* per unit of secondary P2 product output ($E_{i,AV}$), either MWh electricity or t product. The term *avoided emissions* implicitly means that considerations around baselines are integrated.

To handle system multifunctionality, interdependence and the choice of functional unit, the avoided emission term must be expressed in units that are compatible with the of functional unit of analysis, namely primary P1 product or service (Section 5.3.2), and not units of secondary

P2 product or service (e.g., MWh). This is achieved through the CO₂ capture benefit factor, as described previously (Section 5.2.5) and as integrated in Equation 2.

6.4.1 Calculation of CO₂ capture benefit factor

The CO₂ capture benefit factor ($C_{CAP,BF}$) is the rate at which CO₂ emissions are avoided for each unit of CO₂ that is captured and transported for utilisation or storage. The CO₂ capture benefit factor allows system interdependence between up- and downstream systems in a CCUS process chain to be managed effectively. It provides a measure of upstream GHG effects that can be moderated according to the rate at which the primary P1 product consumes CO₂ (as in Equation 2).

It is derived from the following:

$$CO_2 \text{ capture benefit factor } (C_{CAP,BF}) = \frac{E_{i,AV}}{C_{i,CO_2}}$$

[Equation 5]

Where,

$$\begin{aligned} E_{i,AV} &= \text{Avoided emissions (tCO}_2\text{e per functional unit of secondary P2 product; MWh or t product)} \\ C_{i,CO_2} &= \text{CO}_2 \text{ captured for utilisation or storage (tCO}_2\text{ per functional unit of secondary P2 product; MWh or t product)} \end{aligned}$$

The avoided emission rate varies according to fuel type and the assumed baseline as described further below.

The amount of CO₂ captured per unit of secondary P2 product varies according to fuel type and can be measured based on the carbon content of the fuel and/or metered accordingly.

6.4.2 Calculation of avoided emissions

Avoided emissions ($E_{i,AV}$) are calculated from the difference in the GHG emissions intensity of producing a unit of P2 product from a facility with CO₂ capture – plus any increase in emissions attributable to the energy penalty and emissions from CO₂ transport – relative to the emissions intensity of a selected baseline facility. The basic calculation is:

$$\text{Avoided emissions } (E_{i,AV}) = EF_{BL} - (E_{i,CAP,ACT} + E_{i,EP,ACT} + E_{i,TR,ACT})$$

[Equation 6]

Where,

$$\begin{aligned} EF_{BL} &= \text{Emission factor for a baseline facility producing functionally equivalent secondary P2 products or services (tCO}_2\text{e per secondary P2 product; MWh or t product)} \\ E_{i,CAP,ACT} &= \text{Emissions from the facility producing P2 products or services or from where CO}_2 \text{ is captured in the activity (tCO}_2\text{e per secondary P2 product; MWh or t product)} \\ E_{i,EP,ACT} &= \text{Emissions due to energy penalty effects [either extraction of additional fuels / harvesting of biomass or plant de-rating] (tCO}_2\text{e per secondary P2 product; MWh or t product)} \\ E_{i,TR,ACT} &= \text{Emissions from transport of CO}_2 \text{ (tCO}_2\text{e per secondary P2 product; MWh or t product)} \end{aligned}$$

The approach in equation 6 means that the energy penalty associated with CO₂ capture is appropriately counted in the overall assessment. The energy penalty results in the amount of CO₂ captured and available for utilisation being greater than the amount of CO₂ avoided (the amount of CO₂ captured also includes additional amounts of CO₂ generated as a result of the energy load – or ‘penalty’ – of the CO₂ capture plant). Consequently, the amount of CO₂ utilised cannot be directly counted as emission reductions but must be corrected to the level of avoided emissions. The approach also adjusts the emissions occurring upstream in fuel extraction and supply, according to the increase in energy consumption (penalty) associated with CO₂ capture or from the de-rating of a facility due to the energy penalty.

The sections below set out methods for calculating the following for use in Equation 5 and Equation 6:

❑ **Baseline emissions (EF_{BL})**

- Fossil fuels
- Biomass
- Direct air capture

❑ **Activity emissions** consisting:

- Emissions intensity of the facility undertaking CO₂ capture ($E_{i,CAP,ACT}$)
- GHG effects arising from the energy penalty ($E_{i,EP,ACT}$)
- Emissions from CO₂ transport emissions ($E_{i,TR,ACT}$)

6.5 Baseline emissions

Users of these guidelines should make careful and informed choices about the selection of an appropriate baseline scenario and baseline emissions drawing upon jurisdiction-specific circumstances (Section 4.4.1).

Several options are presented below for calculating baseline emissions, with some notes on circumstances where they may be applicable (see also Section 4.4.2).

Baseline emissions should be expressed as a factor in tCO₂e per unit of secondary P2 product output (e.g., tCO₂/MWh).

6.5.1 Historical emissions

Where available, the historical emissions prior to a retrofit of CO₂ capture may be used to provide a relevant estimate of baseline emissions. Baseline emissions can be calculated as follows:

$$\text{Emission factor: baseline } (EF_{BL}) = \frac{E_{HIST,t}}{P2_t}$$

[Equation 7]

Where,

- $E_{HIST,t}$ = Emissions from facility prior to CO₂ capture retrofit over period t (tCO₂e)
- $P2$ = Secondary P2 product output over period t (MWh or t product)
- t = Time period (e.g., one calendar year)

Historical emissions may not always be the most appropriate baseline emissions approach, however. Reasons for fitting CO₂ capture equipment may include:

- Laws prohibiting the continued operation of the facility unabated
- Laws mandating the installation of CO₂ capture equipment on certain emission sources
- Laws prohibiting the construction of new unabated fossil fuel power plants

In any of these circumstances, historical emissions cannot be considered to be the relevant baseline scenario and baseline emissions because unabated emissions would not be allowable under a business-as-usual scenario.

Where historical emissions are not considered to be a relevant or applicable baseline, a performance standard/benchmark baseline method must be used.

6.5.2 Performance standard/benchmark

For new build activities, or as an alternative to historical emissions, various performance standards may be employed to calculate baseline emissions. These include:

- Benchmark performance:** a preferred or 'best-in-class' emission performance benchmark of facilities relevant to the jurisdiction and activity under assessment. This could be, for example, advanced combined cycle gas turbines, a default factor for power generation or a best-in-class product GHG intensity standard for industrial product manufacturing.
- Grid emission factor.** This could be either the published grid intensity for the grid to which the CO₂ capture facility is connected, or more advanced methods. The latter include approaches based on the *build margin*, *operating margin* or *combined margin*, as described in CDM methodology ACM0002 (UNFCCC undated).

Users of these guidelines shall provide clear explanations regarding their choice of baseline scenario and baseline emissions relevant to the particular circumstances of the proposed CO₂ capture and transport activity.

6.5.3 Bioenergy

Where the baseline facility uses biogas or biomass fuel, a baseline emission factor of zero may be assumed ($EF_{BL} = 0$).

This is because biogenic emissions are not counted as an anthropogenic GHG emission source in most accounting methods and standards but is rather calculated as a carbon stock change in removals and land use accounting.

6.5.4 Direct air capture

The baseline emissions factor for a direct air capture (DAC) facility is zero; there is no baseline scenario since the process provides only one product, namely CO₂. Therefore, $EF_{BL} = 0$.

Users of these guidelines may also use other baseline emission factors in cases where the activity involves bioenergy or DAC, including methods applicable to fossil fuels. In such cases, clear explanation of the choices made shall be provided in relevant documentation.

6.6 Activity emissions

6.6.1 Emissions from CO₂ capture

Emissions from CO₂ capture arise due to fugitive losses in the CO₂ capture system and the venting of GHGs due to incomplete or only partial capture. Only GHG emissions arising from fossil fuel combustion need to be counted. Where CO₂ is captured from biomass or directly from air, such emissions do not need to be counted.

Fossil fuels

Net GHG emissions from the facility capturing CO₂ in fossil fuel fired applications can be calculated according to the following:

$$\text{Emission factor: fossil fuel capture } (E_{i,CAP(FF),ACT}) = \frac{E_{ACT,t}}{P2_t}$$

[Equation 8]

Where,

$$\begin{aligned} E_{ACT} &= \text{Emissions from facility with CO}_2 \text{ capture over period } t \text{ (tCO}_2\text{e)} \\ P2 &= \text{Secondary P product output over period } t \text{ (MWh or t product)} \\ t &= \text{Time period (e.g., one calendar year)} \end{aligned}$$

Facility emissions may be calculated using a mass balance based on CO₂ generated minus CO₂ captured, as follows:

$$\text{Emission from facility } (E_{ACT}) = \frac{(\sum FC_{CAP,z,t} \times NCV_{FC,z} \times EF_{CAP,z}) - C_{i,CO_2,t}}{P2_t}$$

[Equation 9]

Where,

$$\begin{aligned} FC_{CAP,z,t} &= \text{Fuel consumption by fuel type } z \text{ in the facility capturing CO}_2 \text{ (mass or unit volume)} \\ NCV_{FC,z} &= \text{Net calorific value for fuel type } z \text{ (GJ per unit mass or volume)} \\ EF_{CAP,z} &= \text{Emission factor for fuel type } z \text{ (tCO}_2 \text{ per GJ)} \\ C_{i,CO_2} &= \text{CO}_2 \text{ captured for utilisation or storage (tCO}_2 \text{ per functional unit of secondary P2 product; MWh or t product)} \\ P2 &= \text{Secondary P product output (MWh or t product)} \\ t &= \text{Relevant period of time (e.g., one calendar year)} \end{aligned}$$

Biomass

In cases where CO₂ is captured from 100% biogenic sources, the approach to establishing emission from CO₂ capture is modified for two reasons: firstly, biogenic CO₂ emissions are rated as zero and therefore not counted as a GHG emission; and, secondly, the capture of CO₂ originating from biogenic sources is counted as a GHG removal.

As a result, the amount of CO₂ captured must be counted as a negative emission (i.e., a removal), which can be deducted from the baseline emissions in Equation 6 to arrive at an estimate of the level of net GHG reduction occurring.

Thus, the relevant emissions factor is the negative of the amount of CO₂ captured:

$$\text{Emission factor: biomass capture } (E_{i,CAP(BIO),CCUS}) = -C_{i,CO_2} \quad \text{[Equation 10]}$$

Where,

$$C_{i,CO_2} = \text{CO}_2 \text{ captured for utilisation or storage (tCO}_2 \text{ per functional unit of secondary P2 product; MWh or t product)}$$

Direct air capture

The approach to calculating the emissions intensity of a direct air capture (DAC) facility is similar to that of biogenic CO₂ inasmuch as any fugitive emissions are zero-rated and the amount of CO₂ captured is counted as a GHG removal. There are no relevant baseline emissions since the only product is CO₂, and therefore a baseline of zero can be assumed (see above). The only difference is that GHG emissions associated with energy use and processes in the DAC plant need to be accounted for.

Therefore, the amount of CO₂ captured minus any GHG emissions associated with energy use and processes in the DAC plant provides the relevant emission factor ($E_{i,DAC}$). This can be deducted from the baseline (of zero) using Equation 6 to arrive at an estimate of the level of net GHG removals occurring.

The activity emissions factor for a DAC facility is calculated as:

$$\text{Emission factor: DAC } (E_{i,CAP(DAC),ACT}) = -C_{i,CO_2(DAC)} + E_{i,DAC} \quad \text{[Equation 11]}$$

Where,

$$\begin{aligned} C_{i,CO_2(DAC)} &= \text{CO}_2 \text{ captured for utilisation or storage (= 1 tCO}_2 \text{ captured)} \\ E_{i,DAC} &= \text{Emissions associated with operation of the DAC plant (tCO}_2 \text{ per tCO}_2 \text{ captured)} \end{aligned}$$

Emissions associated with operation of the DAC plant ($E_{i,DAC}$) can be calculated using modified versions of Equation 13 and Equation 14, where the P2 denominator is replaced by “CO₂ captured for utilisation or storage” ($C_{i,CO_2(DAC)}$), which can be assumed as 1 tonne CO₂.

6.6.2 GHG effects resulting from the energy penalty

The energy penalty imposed by installing CO₂ capture at a facility may lead to secondary GHG effects outside the facility boundary through either of the following:

- ❑ Increased emissions from additional fuel extraction or harvesting, in the case of new build facilities or a retrofit to a facility with capacity addition to provide energy for CO₂ capture;

- ❑ Increased emissions from other facilities that are needed to compensate for a loss in output from a facility retrofitted with CO₂ capture without capacity addition.
- ❑ Direct import of heat or power to provide energy for CO₂ capture.

Methods for calculating the secondary GHG effects for either case are presented below.

The result of either Equation 11, Equation 12 or Equation 13 plus Equation 14 shall be used to estimate total GHG emissions arising from the energy penalty in Equation 6.

Additional fuel extraction or harvesting

Where a facility increases onsite power generation capacity to account for the energy demand posed by CO₂ capture, relative changes in emissions from fuel extraction or harvesting should be incorporated into the calculation of the CO₂ capture and baseline scenarios.

The method for doing so is as follows:

$$\text{Emissions factor: energy penalty } (E_{i,EP (EXT or HARV)}) = \frac{(MJ_{ACT,t} - MJ_{BL,t}) \times EF_{EXT or HARV}}{P2_t}$$

[Equation 12]

Where,

$MJ_{ACT,t}$	=	Fuel consumption in the activity scenario over period t (MJ of fuel consumed)
$MJ_{BL,t}$	=	Fuel consumption in the baseline scenario over period t (MJ of fuel consumed)
$EF_{EXT or HARV}$	=	Emissions factor for fuel extraction or biomass harvesting (tCO ₂ e per MJ energy)
$P2$	=	Secondary P product output (MWh or t product)
t	=	Time period (e.g., one calendar year)

Equation 12 can be readily applied where historical emissions are used to determine the baseline emissions.

Baseline emissions methods involving the use of a performance standard or benchmark cannot easily provide an indication of the assumed rate of fuel consumption in the baseline, because a different fuel type or a range of emissions sources may be used to generate the baseline emission factor. In these cases, it is recommended that Equation 11 be applied using the assumption that the type of fuel consumed in the baseline scenario is the same fuel as used in the activity scenario. This is a conservative assumption.

Compensation by other power plants

Where a power generation facility is de-rated because of the energy penalty imposed by the retrofit of CO₂ capture, the rate of fuel consumption in the plant does not change between the baseline and activity scenario, which means Equation 11 is not applicable. Rather, the plant output changes.

In such circumstances it can be assumed that other plants connected to the electricity grid will increase output to compensate for the reduction in power output of the facility retrofitted with CO₂ capture. The following calculation can be used to an alternative to Equation 11 to calculate the GHG effects of such an arrangement:

$$\text{Emissions factor: energy penalty } (E_{i,EP (DE-RATE),ACT}) = \frac{(MWh_{HIST,t} - MWh_{ACT,t}) \times EF_{GRID,t}}{P2_t}$$

[Equation 13]

Where,

$MWh_{HIST,t}$	=	Energy generation prior to CO ₂ capture retrofit over relevant period t (MWh)
$MWh_{ACT,t}$	=	Energy generation after CO ₂ capture retrofit over period t (MWh)
EF_{GRID}	=	Average grid GHG intensity over relevant period t (tCO ₂ e per MWh)
$P2$	=	Secondary P product output (MWh or t product)
t	=	Time period (e.g., one calendar year)

Import of heat and/or power for CO₂ capture

Where a CO₂ capture or DAC facility is powered partially or entirely by imports of heat and power generated in other facilities, the following can be applied as alternatives to Equation 12 or Equation 13 to calculate the GHG effects of the energy penalty.

$$\text{Emissions factor: energy penalty } (E_{i,EP (IMPORT,HEAT),ACT}) = \frac{\sum FC_{EP,z,t} \times NCV_{EP,z} \times EF_{EP,z}}{P2_t}$$

[Equation 14]

Where,

$FC_{EP,z,t}$	=	Consumption of fuel type z for heat generation over period t (mass or unit volume)
$NCV_{EP,z}$	=	Net calorific value of fuel type z over period t (GJ per unit mass or volume)
$EF_{EP,z}$	=	Emission factor of fuel type z (tCO ₂ per GJ)
$P2$	=	Secondary P product output (MWh or t product)
t	=	Time period (e.g., one calendar year)

$$\text{Emissions factor: energy penalty } (E_{i,EP (IMPORT,ELEC),ACT}) = \frac{MWh_{IMP,t} \times EF_{GRID,t}}{P2_t}$$

[Equation 15]

Where,

$MWh_{IMP,t}$	=	Imports of electricity over period t (MWh)
$EF_{GRID,t}$	=	Emission factor of electricity supplied from grid (tCO ₂ per MWh)
$P2$	=	Secondary P product output (MWh or t product)
t	=	Time period (e.g., one calendar year)

6.6.3 Emissions from CO₂ transport

Transportation of CO₂ can potentially generate emissions of GHGs from two types of sources:

- Fugitive emissions of captured CO₂ due to leaks (pipeline, loading and unloading)
- Combustion emissions from energy used for CO₂ transportation.

Methods for calculating both types of emissions are set out below. All relevant activity emissions sources shall be calculated and added together to establish the total emissions from CO₂ transport.

Emissions from fugitive and combustion sources shall be added together to estimate total GHG emissions arising from CO₂ transport in Equation 6.

Fugitive emissions from transport

Emissions from leaks can be measured using two main methods:

- Mass balance based on the difference in loading and unloading volume/mass
- Inventory based methods drawn from standard leakage rates of equipment and activities (e.g., loading and unloading)

Only mass balance approaches are presented here due to the lack of operational experience and published data on leakage rates for CO₂ transportation equipment. Methods may be developed by operators based on experience and drawn from published methods employed for transport of other types of gases.

Mass balance for estimating fugitive emissions:

$$\text{Transport: fugitive } (E_{i,TR(FUG),ACT}) = \frac{T_{IN,t} - T_{OUT,t}}{P2_t}$$

[Equation 16]

Where,

- $T_{IN,t}$ = Total CO₂ put into the transport system at the CO₂ capture facility (tCO₂) – this should equate to C_{CO2} (tCO₂ captured)
- T_{OUT} = Total CO₂ received at the utilization or storage facility (tCO₂)
- $P2$ = Secondary P product output (MWh or t product)
- t = Relevant period of time (e.g., one calendar year)

Combustion emissions from transport

The following methods are applicable for calculating emissions from mobile sources (ship, road or rail tanker transport) and stationary sources (e.g., pipeline booster stations).

Mobile emission sources – option 1

Emissions from mobile transport sources can be calculated on the basis of distance and the number of trips (or the average transport load):

$$\text{Transport: mobile sources } (E_{i,TR(MS),ACT}) = \frac{N_{TR,t} \times AVD_{TR} \times EF_{TR,x}}{P2_t}$$

[Equation 17]

Where,

$N_{TR,t}$	=	Number of trips during the year y
AVD_{TR}	=	Average round trip distance (from and to) between point of loading of CO ₂ onto rail, road or ship tanker and point of unloading of CO ₂ at the site of utilization or storage (km)
$EF_{TR,x}$	=	Emission factor for transportation for mode x (tCO ₂ per km)
$P2$	=	Secondary P product output (MWh or t product)
t	=	Relevant period of time (e.g., one calendar year)

Mobile emission sources – option 2

Emissions from mobile transport sources can require energy for compression boosting, which may be supplied by natural gas or bought-in grid electricity:

$$\text{Transport: mobile sources } (E_{i,TR(MS),ACT}) = \frac{\sum FC_{TR,z,t} \times NCV_{FC,z} \times EF_{TR,z}}{P2_t} \quad [\text{Equation 18}]$$

Where,

$FC_{TR,z,t}$	=	Fuel consumption by fuel type z for transportation (mass or unit volume)
$NCV_{FC,z}$	=	Net calorific value for fuel type z (GJ per unit mass or volume)
$EF_{TR,z}$	=	Emission factor for fuel type z (tCO ₂ per GJ)
$P2$	=	Secondary P product output (MWh or t product)
t	=	Relevant period of time (e.g., one calendar year)

Stationary emission sources

Transportation of CO₂ in pipelines can involve the use of energy and/or bought-in grid electricity in booster stations, for example.

For energy used in booster stations, the same method as used Equation 14 can be used:

$$\text{Transport: stationary sources (NG)} (E_{i,TR(SS,NG),ACT}) = \frac{NG_{TR,z,t} \times NCV_{FC,z} \times EF_{TR,z}}{P2_t} \quad [\text{Equation 19}]$$

For bought-in electricity, the same method as Equation 15 can be used:

$$\text{Transport: stationary sources (elec.)} (E_{i,TR(SS,GE),ACT}) = \frac{MWh_{IMP,t} \times EF_{GRID,t}}{P2_t} \quad [\text{Equation 20}]$$

6.7 Validity of the baseline over time

Assumptions regarding the baseline scenario and baseline emissions should be periodically re-evaluated to test for their ongoing validity.

- Historical emissions:** calculation of baseline emissions using historical emissions is valid for a maximum of 10 years. After 10 years, a performance standard/benchmark should be adopted. The GHG emissions reduction benefit assessment may also be terminated after 10 years where credits are being awarded.

- ❑ **Performance standard/benchmark emissions:** if using a static performance standard/benchmark, the emission factor shall be re-evaluated at, at the latest, 5 years after project start date and every 5 years thereafter. Dynamic performance standards shall be re-evaluated each year as part of project monitoring (Table 6.1).

6.8 Data and monitoring

Table 6.1 below outlines data collection and monitoring requirements for the compilation of both *ex ante* and *ex post* estimates needed to complete this module. Results of analysis can be used to estimate the CO₂ capture benefit factor as applied in Equation 2.

Table 6.1 Data needed to estimate GHG effects from CO₂ capture and transport

Factor	Desk-based GHG assessment (<i>ex ante</i>)	Monitoring and <i>ex post</i> GHG assessment
$C_{CAP,BF}$	Derived from other factors	
C_{i,CO_2}	Engineering design specifications for the rate of CO ₂ capture and secondary product (P_{2t}).	Calculated from: <ul style="list-style-type: none"> Metered CO₂ at the outlet of the CO₂ capture facility over period t (in tCO₂) Measured P_{2t}
EF_{BL}	Assumed baseline emissions factor established following guidance in Section 6.5	<i>Static baseline</i> : based on same factor as applied <i>ex ante</i> <i>Dynamic baseline</i> (e.g., grid emissions factor): based on annual emissions data and output produced by, for example, the grid system operator and/or reported average grid emission factor
E_{ACT}	Difference between calculated total GHG generated at the facility (based on total fuel consumption of the facility) and the engineering design specification for the CO ₂ capture facility.	Calculated from: <ul style="list-style-type: none"> Fuel consumed in the facility over period t, derived from fuel purchase data or weighbridge data (in MJ) Emission factor for fuel consumed at the facility (tCO₂/MJ) Metered CO₂ at the outlet of the CO₂ capture facility over period t (in tCO₂)
P_{2t}	Nameplate capacity of plant (annualised by run time)	Measured P2 product or service output of the facility over period t .
$E_{i,DAC}$	Engineering design specifications for energy and heat rates for direct air capture plant	Calculated from: <ul style="list-style-type: none"> Fuel consumed in the DAC facility over period t, derived from fuel purchase data or weighbridge data (in MJ) Emission factor for fuel consumed at the DAC facility (tCO₂/MJ)
$MJ_{ACT,t}$	Engineering design specifications for fuel consumption in facility with CO ₂ capture.	Fuel consumed in the facility over period t , derived from fuel purchase data or weighbridge data (in MJ)
$MJ_{BL,t}$	Engineering design specifications for fuel consumption for an equivalent facility as in the activity scenario but without CO ₂ capture.	Same as <i>ex ante</i> assumptions
EF_{EXT} or $HARV$	Published emissions factors for different types of fuel extraction and harvesting activities (see Annex A-1 for examples)	Same as <i>ex ante</i> assumptions
$MWh_{HIST,t}$	Records of output of facility prior to any retrofitting of CO ₂ capture	Same as <i>ex ante</i> assumptions
$MWh_{ACT,t}$	Engineering design specifications for re-rated nameplate capacity of the facility following retrofit of CO ₂ capture	Measured P2 product or service output of the facility over period t (i.e., electricity exported by facility over period t , metered at the busbar)
$FC_{EP,z,t}$	Engineering design specifications for energy consumption in CO ₂ capture plant. Assumed source of heat and/or power.	Metered imports of heat energy. Records of facility operator providing heat and power.
$NCV_{EP,z}$	Assumed energy content of fuels used for powering CO ₂ capture plant	Records of facility operator providing heat and power.
$EF_{EP,z}$	Published emissions factors for relevant fuels	Same as <i>ex ante</i> assumptions
$MWh_{IMP,t}$	Engineering design specifications for electricity consumption in CO ₂ capture plant. Assumed source of electricity.	Metered imports of electrical energy
$EF_{GRID,t}$	Emissions factor for electricity grid in planned location of CO ₂ capture facility.	Annual emissions data and output produced by the grid system operator and/or reported average grid emission factor
$T_{IN,t}$	Engineering design specifications for the mass of CO ₂ captured over period t	Metered CO ₂ at the outlet of the CO ₂ capture facility over period t (in tCO ₂)
$T_{OUT,t}$	Engineering design specifications for the mass of CO ₂ captured over period t (i.e., = T_{IN} and assume zero leaks)	Metered CO ₂ arriving at the utilisation or storage facility over period t (in tCO ₂)
$N_{TR,t}$	Calculated from CO ₂ capture mass and tanker carrier capacity	Records of CO ₂ shipments
AVD_{TR}	Assumed distance to utilisation or storage location from capture facility (x2)	Records of CO ₂ shipments
EF_{TR}	Derived from published sources for the relevant mode of transport x	Same as <i>ex ante</i> assumptions
$FC_{TR,t}$	Consumption rate of assumed fuel used for mode of transportation	Records of CO ₂ shipments
$NCV_{TR,z}$	Assumed energy content of fuels used for transporting CO ₂	Records of CO ₂ shipments
$EF_{TR,z}$	Published emissions factors for relevant fuels	Same as <i>ex ante</i> assumptions

7 ACCOUNTING FOR CO₂ UTILISATION

7.1 Introduction

CCU technologies are widely considered to offer benefits for the climate because they involve the capture and utilization of CO₂ that would otherwise be emitted to the atmosphere (e.g., the Global CO₂ Initiative, 2016; McKinsey & Company, 2018). Such conclusions are usually predicated on a number of factors being in place, however, in particular plentiful availability of low emissions (renewable) electricity. This fact has led some analysts to cast doubt upon the climate efficacy of CCU when compared to scenarios where the low emissions electricity is used directly, and captured fossil CO₂ is geologically stored rather than utilised (Carlos Abandes *et al.*, 2017).

Uncertainty in respect of the emissions reduction potential of CCU is understandable; the low reactive state of CO₂ under standard conditions means that its utilisation requires significant energy and materials inputs in the form of catalysts to lower its activation state (Centre for Low Carbon Futures, 2011). This presents an energy and materials trade-off.

The key challenges for quantifying and assessing the GHG effects of CO₂ utilisation were described in Section 5.2. These guidelines address these challenges by setting out methods that separately calculate upstream effects using the CO₂ benefit factor method (Section 6), and downstream effects as covered by this module. A separated approach helps to enhance the clarity of reporting of GHG effects arising from CCU technology across the process chain.

The focus of this module is therefore on identifying and measuring GHG effects that can arise from product substitution of conventionally-derived incumbent products by CO₂-derived products. This can lead to two types of GHG effect:

- ❑ **Process changes:** the fabrication of CO₂-derived products may lead to similar, higher or lower levels of GHG emissions compared to the fabrication of conventionally-derived, functionally-equivalent, products, which can lead to neutral, negative or positive GHG effects (see Section 5.2.5)
- ❑ **Performance changes:** changes in functionality (performance) arising from the use of CO₂-derived products compared to incumbents may also create further secondary GHG effects. This can arise, for example, through changes in the levels of energy and materials consumed in final use of the product. In other words, imperfect substitution may occur which can lead to changes in GHG effects. Some CCU process chains reportedly lead to enhanced product quality, which can lead to overall performance improvements and emissions reduction, while others may have the opposite effect (see Section 5.2.5).

In the case of the latter, the choice of assessment boundary and functional unit will impact on whether these GHG effects are captured in the GHG assessment or not (see Box 5.1).

Approaches to quantifying emission sources and GHG effects attributable to process and performance changes arising from CO₂-derived products are described in this module, based on methods for identifying relevant baselines and activity data.

7.2 Scope

Methods presented are applicable to CO₂ utilisation for the following types of activities:

- Electro- or renewable fuel fabrication including:
 - Methanol
 - Synthetic natural gas
 - Others (e.g., dimethyl ether; alkanes)
- Chemical synthesis including:
 - Methanol based chemicals (e.g., methanol to olefins)
 - Others (e.g., organic carboxylation/polymerization)
- Mineralisation including:
 - Sodium bicarbonate
 - Aggregates and block
 - Concrete curing
- Enhanced oil recovery; EOR

Methods account for incomplete utilisation of input CO₂ and resultant fugitive emissions at CO₂ utilisation facilities – this is accomplished using a CO₂ mass balance of across the facility.

Emissions arising from auto-generation and bought-in power for product fabrication are also included.

The primary approach measures the following:

- Process changes:** the net GHG effect of employing CO₂-based fabrication processes to make functionally-equivalent products relative to fabrication of a conventionally-derived product.

The primary assumption is that the CCU process results in a fully-interchangeable, functionally-equivalent product that can substitute a conventionally-derived incumbent production on a 1:1 basis (i.e., perfect substitution).

Users may also include an assessment of the GHG emissions and GHG effects relating to the following emission sources where these are considered relevant to the GHG assessment:

- Secondary processing:** emissions from secondary processing may be included where a cradle-to-grave assessment is to be carried out. This usually involves using a functional unit other the primary P1 (CO₂-derived) product (e.g., a final product made from a CO₂-derived intermediate) with associated conditions and limitations as described below (Section 7.3.2).
- Performance changes:** GHG effects arising from performance changes must be counted where a functional unit other than the primary P1 (CO₂-derived) product is used. Additionally, in some applications, for example CO₂ concrete curing, changes in product performance may occur without the need to use a different functional unit to the primary P1 product.

Users shall take note of the principle of conservativeness when considering the inclusion of additional secondary GHG effects. Where the effort, complexity and transparency of GHG assessments may be negatively affected by the inclusion of minor secondary GHG effects and/or the use of functional units other than the primary P1 product, these should be excluded from the assessment.

Users shall consider the source of hydrogen where this is bought-in rather than manufactured on-site, and account for emissions from its manufacture as described previously (Section 5.3.6).

In all cases, emissions from product use and end-of-life must be counted where CO₂ retention cannot be guaranteed for a period of time greater than 100 years. In practice, this means for all CO₂-derived products other than those involving CO₂ mineralisation, the carbon stored in the product should be assumed to be instantaneously oxidised and emitted in the GHG assessment.

Users should count the emissions from product use and end-of-life in both the baseline and activity scenario. In practice, emissions in both the baseline and activity scenario should cancel each other out i.e., a net zero GHG effect. However, the reporting of such emissions can enhance the transparency and improve knowledge about the GHG effects arising from CCU technologies (see Section 5.2.3).

Users undertaking GHG assessment of CO₂-EOR operations must additionally apply Section 8.6.4 and Section 8.8 to provide assurances over the permanence of CO₂ injected into operational hydrocarbon reservoirs.

7.3 Assessment boundary

Users must select whether to employ cradle-to-gate or cradle-to-grave assessment boundaries (see Box 5.1).

These guidelines provide only limited guidance for cradle-to-grave assessments due to the additional complexities this poses to GHG assessments, as described below.

7.3.1 Cradle-to-gate GHG assessment

Users shall undertake a gate-to-gate GHG assessment of the CCU fabrication/production process. This can be applied in conjunction with the CO₂ benefit factor (Section 6 and Equation 2) to provide a cradle-to-gate GHG assessment for the full CCU process chain up to the gate of the CCU fabrication/production facility. Product use and end-of-life emissions shall be included based on assumed CO₂ retention times as described above.

A cradle-to-gate approach is valid where the CO₂-derived product is directly interchangeable with conventionally-produced incumbent counterparts. In these circumstances, 'perfect substitution' at a rate of 1:1 can be assumed (i.e., a functional unit of CO₂-derived product substitutes the same functional unit of conventional product), with resultant GHG effects. These characteristics preclude the need to assess any further GHG effects arising from either secondary processing or performance changes.

The following emissions sources should be included in the assessment boundary for CO₂ utilisation:

1. **Combustion emissions from stacks and other point sources across the entire facility where CO₂ is being utilised.** Emissions sources include emission stacks from onsite heat and power generation.
2. **Fugitive emissions from losses of containment of GHGs during CO₂-derived product fabrication.** Emissions of captured and imported CO₂ from vessels and pipework at the CO₂-product fabrication facility due to incomplete reactions occurring in the process, leaks or losses in solution from the facility. Emissions of CH₄ and CO₂ arising during separation and recycle in CO₂ enhanced oil recovery operations, and seepage emissions from geological storage where undertaken in conjunction with CO₂-EOR operation.
3. **Combustion emissions associated with bought-in heat and power used for CO₂-derived product fabrication.** Indirect or “Scope 2” emissions can arise from the generation of electricity or heat used by the facility that occur outside of the facility boundaries but are directly attributable to the activity. Sources include grid electricity and imports of heat from neighbouring facilities.
4. **Emissions from product use and disposal.** Some CCU process chains result in the oxidation and re-emission of carbon as CO₂ during product use or disposal. Examples include the combustion of CO₂-derived methanol (instantaneous re-emissions upon use) or the decay of CO₂ derived chemical products such as polycarbonate foams (instantaneous emission [incineration] or slow release [landfill] depending of the end-of-life pathway). Carbon stored in these products should be assumed to instantaneously oxidise upon production and included in the activity and baseline GHG inventory
5. **Emissions from performance changes where this has measurable impacts on process inputs such as material consumption.** Performance changes may also be included where the fabrication of the CO₂-derived product has measurable changes to process inputs relative to an incumbent product. An example is CO₂ concrete curing, which is reported to result in an enhanced fabrication performance requiring lower materials inputs during fabrication relative to conventional concrete.

Any removals of CO₂ from the atmosphere by adsorption into the CO₂-derived product during and after fabrication shall not be counted as a removal for reasons of conservativeness.

Embedded emissions associated with bought-in materials used in the baseline and activity (CO₂ utilisation) process fall outside of the assessment boundary applied in these guidelines and should therefore not be included as an emissions source nor counted as emissions. These sources are excluded because they are challenging to quantify, and positive and negative GHG effects associated with these sources cannot easily be attributed to the activity nor its owners/operators.

Users wishing to consider GHG effects arising from changes in emissions from these sources should adopt a life cycle analysis based approach to the GHG assessment, and use cradle-to-grave assessment boundaries as outlined below.

7.3.2 Cradle-to-grave GHG assessment

Users may wish to undertake gate-to-grave assessment of the CO₂-derived products. Where this is selected, GHG emissions from secondary processing must also be included in addition to those emission sources listed in Section 7.3.1 (see Figure 7.1). The results of this analysis can be

applied in conjunction with the CO₂ benefit factor (Section 6 and Equation 2) so as to provide a cradle-to-grave GHG assessment for the full CCU process chain.

Additional complexities are presented by cradle-to-grave GHG assessment which must be taken account of by the user, as described below.

Users applying cradle-to-grave GHG assessment must consider at least the following additional factors in their analysis:

- The choice of functional unit.** Cradle-to-gate analysis implies the need to use a functional unit other than the primary P1 (CO₂-derived) product for the GHG assessment i.e., a final product into which a CO₂-derived intermediate has been used. The rate at which the CO₂-derived intermediate product is consumed in the fabrication of the final product must therefore be accounted for, which fundamentally changes the basic accounting formula in Equation 2.
- Assumptions regarding functional equivalence.** Selecting a functional unit other than the primary P1 product poses additional considerations regarding the performance and durability of the product. Changes in product performance may lead to positive or negative GHG effects during its use and also lead to changes in the lifespan of the product relative to a conventionally-derived incumbent product.
- The selection of a relevant baseline scenario.** The choice of baseline scenario (or reference product) will be complicated by employing a functional unit other than the primary P1 (CO₂-derived) product. The market into which final products will be sold will inevitably be fundamentally different to that of an intermediate CO₂-derived product. For example, petroleum markets have fundamentally different characteristics and regulatory features in comparison to methanol markets, which affects choices around the baseline scenario. For example, if the selected functional unit is a unit of petroleum-methanol blend product (e.g., 1 litre), the baseline scenario needs to consider the wide range of petroleum and alternative products that the petroleum-methanol blend could displace (e.g., corn ethanol blend; sugar derived ethanol blend; algae-derived ethanol blend), rather than just simply alternative sources of methanol products.
- The calculation of baseline emissions.** The GHG emissions inventory associated with a more complex final product as the baseline scenario will require significantly greater effort to calculate relative to more simple intermediate products. Consequently, greater uncertainty will also be created in the calculated baseline emissions.

All of the factors listed pose significant additional complexities for cradle-to-gate GHG assessment that are not fully covered in these guidelines. Users wishing to adopt this approach are referred to the relevant life cycle analysis (LCA) standards listed in Section 5.4 for further guidance on how to effectively account of these aspects.

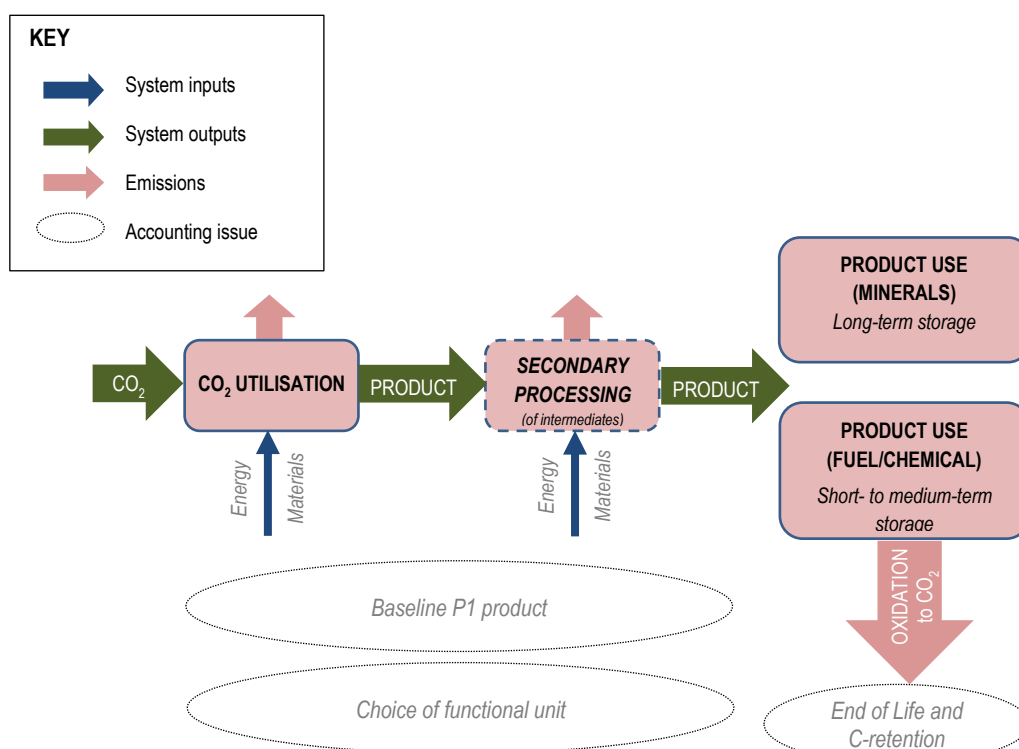
As a minimum, users of these guidelines adopting cradle-to-grave GHG assessment boundaries must clearly report the following additional features applied in their analysis of GHG effects:

- How the rate of consumption of the primary P1 (CO₂-derived) intermediate product in the fabrication of final product has been accounted for and used to adjust calculated GHG effects.

- ❑ All assumptions regarding changes in product performance and durability relative to conventionally-derived incumbent products used in the baseline scenario.
- ❑ How the baseline scenario has been determined based on specific market conditions of the product used as the functional unit of analysis.
- ❑ How baseline emissions have been compiled based on all the above.

GHG assessment boundaries and accounting choices are shown schematically below (Figure 7.1).

Figure 7.1 Schematic overview of CO₂ utilisation system components



Source: Authors

7.4 Calculation of GHG effects

7.4.1 Calculation for process changes

In accordance with Equation 2, the downstream GHG effects arising from process changes associated with the fabrication, supply and use of CO₂-derived products are isolated and measured as follows:

$$GHG\ Effect\ [P1\ only] \left(\frac{GHG}{ACT_{CCUS}} \right) = BL_{E,i,P1} - PE_{E,i,P1[ONLY]} \left[= \sum_{s=1}^n E_{i,s,ACT} \right]$$

[Equation 21]

Where, as Equation 2.

The GHG effects of capturing CO₂ – the parts in parenthesis in Equation 2 – are excluded in Equation 21 for illustrative purposes, but are factored into the overall assessment alongside the comparison of product GHG intensity to provide a complete GHG assessment (as in Equation 2).

The method outlined is applicable primarily to cradle-to-gate analysis.

Cradle-to-grave analysis may employ a similar approach but adapted according to the guidance outlined above (Section 7.3.2).

7.4.2 Calculation for performance changes

In circumstances where the primary P1 product generates performance changes compared to incumbent products (i.e., they are not functionally equivalent), then imperfect substitution may be assumed by the user.

This may be calculated by applying a modified version of Equation 21/Equation 2 as follows:

$$GHG\ Effect\ [P1\ only] \left(\frac{GHG}{ACT_{CCUS}} \right) = BL_{E,i,P1} - \left(PE_{E,i,P1[ONLY]} \left[= \sum_{s=1}^n E_{i,s,ACT} \right] \times \underline{SR} \right)$$

[Equation 22]

Where, as Equation 2, plus;

$$SR = \textit{Substitution rate (rate at which P1 product substitutes conventionally-derived incumbent)}$$

A modified substitution rate acts to capture GHG effects related to changes in the consumption of a product created by differential performance (e.g., durability). The substitution rate must therefore be established by users according to technical analyses of the qualities (strength, durability, performance etc.) of the CO₂-derived product relative to the conventionally-derived incumbent (baseline) product that is determined to be substituted by the primary P1 product.

Other GHG effects may also arise as a consequence of changes in product consumption and imperfect substitution, for example:

1. Transport emissions (e.g., decreased product shipments)
2. Processing emissions (e.g., decreased emissions from product fabrication)
3. Consumption emissions (e.g., reduced materials consumption in product fabrication)

These GHG effects should be captured in the calculation of activity emissions ($E_{i,s,ACT}$), albeit dependent on the assessment boundaries. For example, changes in GHG effects arising in consumption emissions are excluded since materials consumption falls outside the recommended assessment boundary; measurement of transport emissions will depend on how the “gate” of the facility is determined by the user (Section 7.6.4).

7.5 Baseline emissions

Users of these guidelines should make careful and informed choices about the selection of an appropriate baseline scenario and baseline emissions according to jurisdiction-specific circumstances, as described in Section 4.4.1.

Several options are presented below for calculating baseline emissions, with some notes on circumstances where they may be applicable (see also Section 4.4.2).

Baseline emissions should be expressed in tCO₂e per unit of primary P1 product output (e.g., tCO₂/tonne or MJ of product), according to the selected functional unit of the assessment.

7.5.1 Process emissions

Historical emissions

Where available, the historical emissions prior to a retrofit of facility with CO₂ utilisation may be used to provide a relevant estimate of baseline emissions from product fabrication. This is only applicable where the output of the facility in the new activity scenario will be a functionally-equivalent product as produced in the baseline scenario.

Where this is determined to be the case, baseline emissions can be calculated as follows:

$$\text{Emission factor: baseline } (BL_{E,i,P1}) = \frac{E_{HIST,t}}{P1_t}$$

[Equation 23]

Where,

$E_{HIST,t}$	=	Emissions from facility prior to retrofit of CO ₂ utilisation over period t (tCO ₂ e)
$P1$	=	Primary P1 product output over period t (MWh or t product)
t	=	Time period (e.g., one calendar year)

In most circumstances it is unlikely that a facility would be retrofitted with CO₂ utilisation, with the exception of CO₂-EOR. However, since CO₂-EOR involves a shift in operations, it may be preferable to use a performance standard or benchmark. A performance standard or benchmark will therefore likely provide a more appropriate measure of baseline emissions in most circumstances.

Performance standard/benchmark

A performance standard or benchmark approach to determining baseline emissions involves identifying and characterising the cradle-to-gate (or cradle-to-gate, where this is employed) GHG emissions associated with fabrication of a conventionally-derived incumbent product that is most likely to be displaced by the primary P1 (CO₂-derived) product in the activity scenario.

To understand the most likely product that will be displaced by a CO₂-derived product, and its related emissions, users shall undertake analysis and report the findings regarding the following:

- Market characteristics and supply base.** The characteristics and supply-base of the market into which the primary P1 (CO₂-derived) product will be sold in the activity scenario.

- ❑ **Product in that market.** The most likely functionally-equivalent current product in that market that could be displaced by supply of a CO₂-derived alternative. This could be based on economic analysis or other reasonable assumptions about the nature of the supply-base to the relevant market, for example, marginal products, most expensive product or products that are least favoured.
- ❑ **Product emissions.** The cradle-to-gate GHG emissions intensity (tCO₂e/tonne or MJ product) of the product that is identified as the most likely to be displaced and substituted.

In terms of the last bullet, users may use published information provided by retailers, information published in other reputable literature sources, or compile their own product GHG intensity assessment. Potential information sources include:

- ❑ Ecoinvent® database (and authorised re-sellers of Ecoinvent data)
- ❑ The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model (for fuel products)
- ❑ Other literature such as LCA studies.

Users must ensure that the results of analysis used to determine the performance standard or benchmark use the same:

- ❑ **Assessment boundary** and emissions sources as applied in calculating the activity emissions in the GHG assessment (Section 7.3);
- ❑ **Functional unit** as being applied across the entire GHG assessment. For cradle-to-gate assessment, this should be the same as the primary P1 (CO₂-derived) product.

7.5.2 Product use emissions

Emissions from product use/end-of-life shall be added to the estimated process emissions to determine baseline emissions for the primary P1 product. Emissions from product use and end-of-life may be derived from either:

- ❑ Calculated, according to the carbon content of a functional unit of baseline product and assuming 100 percent oxidation of the carbon content;
- ❑ Published emission factors for relevant products.

Where the baseline and primary P1 product are functionally-equivalent and have the same carbon content, baseline emissions from product use can be assumed to be the same as the activity emissions for product use.

7.6 Activity emissions

Activity emissions consist of the emissions attributable to the facility utilising CO₂ to fabricate the primary P1 product (process emissions) and emissions from product use. It may also include other sources such as transport emissions and secondary processing if considered relevant.

The main emissions sources that must be quantified within these facilities are described above (Section 7.3). Methods to calculate different emission sources are set out below.

7.6.1 Fugitive emissions

CO₂-derived product fabrication

Losses of bought-in CO₂ and resultant emissions to atmosphere can occur from vessels and pipework due to leaks and incomplete utilisation of CO₂ in reactions. Such CO₂ may be emitted through vents or in solution.

Emissions can be estimated using a mass balance across the facility as follows:

$$\text{CO}_2 \text{ utilisation: fugitive emissions } (E_{i,s,ACT(FUG)}) = \frac{U_{CO_2,t} - P1_{CO_2,t}}{P1_t}$$

[Equation 24]

Where,

- U_{CO₂}* = CO₂ bought-in for utilisation over period *t* (= *T_{OUT}* in Equation 16; *tCO₂*)
- P1_{CO₂}* = Mass of CO₂ integrated into P1 product over period *t* (*tCO₂*)
- P1* = Primary P1 product output over period *t* (in functional unit of analysis; tonnes or MJ etc)
- t* = Relevant period of time (e.g., one calendar year)

CO₂ enhanced oil recovery operations

CO₂ EOR operations involve the production of crude oil that contains dissolved CO₂ injected for the purposes of its recovery. The dissolved CO₂ is separated at the surface and re-injected into the reservoir – a process termed CO₂ recycle.

A fraction of CO₂ may be emitted to the atmosphere at oil production battery due to leaks from vessels and pipework, and a fraction will be left in solution in the exported crude oil, and eventually emitted to the atmosphere.

A significant portion of the injected CO₂ is retained in the geological reservoir and is never co-produced with the oil, posing the need for continuous fresh supply of make-up CO₂ for injection with the recycled CO₂. Because the portion retained in the reservoir is unknown, it is not possible to apply a mass balance to calculate fugitive emissions of CO₂.

Users must therefore estimate fugitive losses due to leaks and in solution and count these as fugitive emissions per primary P1 product output (crude oil) in the same way as described in Equation 24.

In addition, users must apply methods set out in Sections 8.6.4 and 8.8 to account for permanence, seepage and carbon reversal risk for geological storage of CO₂.

7.6.2 Combustion emissions

Emissions from onsite generation of heat and power for both primary P1 product fabrication and/or secondary processing can be calculated using the method in Equation 14, but normalised to the functional unit of analysis i.e., primary P1 product output.

7.6.3 Bought-in electricity and heat

Emissions from bought-in heat and power for both primary P1 product fabrication and/or secondary processing can be calculated using the same method in Equation 14 and Equation 15, but normalised to the functional unit of analysis i.e., primary P1 product output.

7.6.4 Transport emissions

Emissions from the transport of a P1 product from the point of fabrication to its point of use may be included by users in the calculation of CCU activity emissions.

In circumstances where the activity and baseline product are functionally-equivalent, and therefore perfect substitution is assumed, there should be no net change in GHG effects – the same emissions occur in both the activity and baseline scenario. Consequently, these emissions may be excluded in the gate-to-gate analysis carried out under this module.

In circumstances where performance changes are considered relevant and imperfect substitution is assumed (Section 7.4.2), then changes in GHG effects may occur. To account for these GHG effects, it is firstly important to note that emissions from product transport are not usually included in published cradle-to-gate emissions estimates for products (Section 7.5.1). For this reason, the calculation must incorporate changes between the baseline and activity emissions.

Emissions arising from the transport of the primary P1 product to its point of use can be calculated using modified forms of either Equation 17 or Equation 18, but normalised to the functional unit of analysis (i.e., primary P1 product output).

The GHG effects arising from differential transport requirements can be estimated by including the calculated emissions and applying the substitution rate assumed in Equation 22 and in a modified form of Equation 2.

7.6.5 Product use emissions

Emissions from product use and end-of-life shall be calculated, according to the carbon content of a functional unit of primary P1 product and assuming 100 percent oxidation of the carbon content.

Where the baseline and primary P1 product are functionally-equivalent and have the same carbon content, activity emissions for product use can be assumed to be the same as the baseline emissions for product use.

7.7 Validity of the baseline over time

Assumptions regarding the baseline scenario and baseline emissions should be periodically re-evaluated to test for their ongoing validity in the same way as for the CO₂ capture and transport module.

- ❑ **Historical emissions:** calculation of baseline emissions using historical emissions is valid for a maximum of 10 years. After 10 years, a performance standard/benchmark should be adopted. The GHG emissions reduction benefit assessment may also be terminated after 10 years where credits are being awarded.
- ❑ **Performance standard/benchmark emissions:** if using a static performance standard/benchmark, the emission factor shall be re-evaluated at, at the latest, 5 years after project start date and every 5 years thereafter. Dynamic performance standards shall be re-evaluated each year as part of project monitoring (Table 7.1).

Key additional factors to consider include when re-assessing the performance standard/benchmark include:

- Are incumbent products still functionally equivalent?
- Is the assumed substitution rate still valid?
- Are assumptions around the assumed baseline product and baseline emissions still valid?

Where the answer to any of these questions is negative, the baseline scenario shall be re-evaluated, and baseline emissions recalculated.

These checks should be made at least every 5 years during project implementation.

7.8 Data and monitoring

Table 7.1 below outlines data collection and monitoring requirements for the compilation of both *ex ante* and *ex post* estimates of GHG emissions from CO₂ utilisation as needed to complete this module.

Results of analysis can be used to estimate the baseline and activity emissions for application in Equation 2.

Table 7.1 Data needed to estimate GHG effects from CO₂ capture and transport

Factor	Desk-based GHG assessment (<i>ex ante</i>)	Monitoring and <i>ex post</i> GHG assessment
$PE_{E,i,P1[ONLY]}$	Estimate of the total emissions from all sources attributable to the planned CCU fabrication facility including: <ul style="list-style-type: none"> • Fugitive emissions • Combustion emissions • Emissions from bought-in heat and/or power (Scope 2) • Transport emissions (where considered relevant) 	Measurements of the following at the facility: <ul style="list-style-type: none"> • Bought-in CO₂ • CO₂ integrated into primary P1 products produced (based on stoichiometric reaction rates) • Fuel consumption • Electricity consumption
$BL_{E,i,P1}$	Baseline emissions from conventionally-derived incumbent product that is assumed to be displaced by the primary P1 product in the activity scenario. Emissions per functional unit of analysis shall be determined from: <ul style="list-style-type: none"> • Historical emissions • Published data on cradle-to-gate emissions for selected products • Calculated by user 	
SR	Estimated from technical analysis of primary P1 product performance relevant to the selected baseline product.	
P1	Engineering design specifications for total primary P1 product from the facility over period t (tonnes or MJ)	Measured production of the P1 product fabrication facility over period t (tonnes or MJ)
U_{CO2}	Engineering design specifications for CO ₂ consumption at the P1 product fabrication facility.	Metered and/or purchase records of CO ₂ delivered to the P1 product fabrication facility over period t (in tCO ₂).
$P1_{CO2}$	Nameplate capacity of the P1 product fabrication facility. Calculated stoichiometric CO ₂ utilisation rate in reactions occurring in the P1 product fabrication processes.	Measured output of the P1 product fabrication facility over period t (tonnes or MJ) and the calculated stoichiometric content of CO ₂ integrated into the P1 product.
$FC_{P1,z,t}$	Engineering design specifications for energy consumption in P1 product fabrication facility. Assumed source of heat and/or power.	Metered imports of heat energy. Records of facility operator providing heat and power.
$NCV_{P1,z}$	Assumed energy content of fuels used at the P1 fabrication facility.	Records of facility operator providing heat and power.
$EF_{P1,z}$	Published emissions factors for relevant fuels	Same as <i>ex ante</i> assumptions
$MWh_{P1,t}$	Engineering design specifications for electricity consumption in P1 product fabrication facility. Assumed source of electricity.	Metered imports of electrical energy
$EF_{GRID,t}$	Emissions factor for electricity grid in planned location of P1 product fabrication facility.	Annual emissions data and output produced by the grid system operator and/or reported average grid emission factor
$N_{P1,TR,t}$	Calculated from P1 product output mass/volume and truck capacity	Records of P1 product shipments
$AVD_{P1,TR}$	Assumed distance to final use location from P1 product fabrication facility (x2)	Records of P1 product shipments
$EF_{P1,TR}$	Derived from published sources for the relevant mode of transport x	Same as <i>ex ante</i> assumptions
$FC_{P1,TR,t}$	Consumption rate of assumed fuel used for mode of transportation	Records of P1 product shipments
$NCV_{P1,TR,z}$	Assumed energy content of fuels used for transporting P1 product	Records of P1 product shipments
$EF_{P1,TR,z}$	Published emissions factors for relevant fuels	Same as <i>ex ante</i> assumptions
$E_{i,s,ACT(FUG-EOR)}$	Estimated emissions at crude oil production and processing facility. Estimated CO ₂ lost in solution in exported crude oil.	

8 ACCOUNTING FOR CO₂ STORAGE

8.1 Introduction

The technical characteristics of geological CO₂ storage activities present different GHG accounting challenges to those of CCU. In general, accounting approaches are less complex because there is no system multifunctionality to consider. On the other hand, technical aspects and monitoring requirements are more onerous because of geological CO₂ storage site selection and management requirements.

Issues in these contexts primarily relate to the choice of assessment boundaries and the handling of seepage and permanence. Assessment boundaries are important in determining the scope of monitoring of the geological storage site. Seepage and permanence pose a risk of *carbon reversal* occurring if geologically sequestered CO₂ is released back the atmosphere at a future point in time.

If seepage and carbon reversal occurs after project start, the efficacy of CCS as a climate change mitigation technology is eroded and the environmental integrity of any financial reward provided for the avoidance of CO₂ emissions is undermined. These concerns apply equally to situations where geological storage forms part of the incidental or planned component of a CCU activity (e.g., in enhanced oil recovery).

Concerns over boundaries, seepage and permanence have been addressed in many GHG accounting schemes in place around the world, including in Europe, the USA, Canada and internationally under the UNFCCC. These guidelines follow approaches applied in those jurisdictions.

8.2 Scope

Methods presented are applicable to geological CO₂ storage in the following types of reservoirs:

- Saline aquifers
- Depleted hydrocarbon reservoirs
- Operational oil reservoirs (for EOR) – in conjunction with methods set out in Section 7

This module contains guidance on technical surveys and monitoring requirements to be implemented both *ex ante* and *ex post*, since these are critical aspects of designing secure CO₂ geological storage operations with zero seepage.

Guidance provided in this module for storage site characterisation, selection and monitoring must be checked with a national competent authority before any work on a project commences. Applicable national laws and regulations (e.g., oil & gas development regulations; environmental impact assessment laws etc.) must be taken into account alongside the broad guidance provided herein.

8.3 Assessment boundary

The following emissions sources should be included in the assessment boundary for CO₂ storage facilities:

1. **Combustion emissions from stacks and other point sources at CO₂ storage facility.** Emissions sources include emission stacks from onsite heat and power generation.
2. **Combustion emissions associated with bought-in heat and power.** Indirect or “Scope 2” emissions can arise from the generation of electricity or heat used by the project that occur outside of the project boundaries but are directly attributable to the activity. Sources include grid electricity and imports of heat from neighbouring facilities.
3. **Fugitive emissions from losses of containment of GHGs across the CO₂ injection and storage site.** Emissions can arise from leaks of CO₂ at injection facilities (including emissions of CH₄ and CO₂ arising during separation and recycle in CO₂-EOR operations); and, seepage from geological storage sites (including mobilisation and seepage of CH₄ from the subsurface resulting from CO₂ injection).

Embedded emissions associated with bought-in materials used in the baseline and activity (CO₂ storage) process fall outside of the assessment boundary applied in these guidelines and should therefore not be included as an emissions source nor counted as emissions. These sources are excluded because they are challenging to quantify, and positive and negative GHG effects associated with these sources cannot easily be attributed to the activity nor its owners/operators.

Users wishing to consider GHG effects arising from changes in emissions from these sources should adopt a life cycle analysis based approach to the GHG assessment, and use cradle-to-grave assessment boundaries as outlined in Section 7.3.

8.3.1 Defining boundaries of the CO₂ storage complex

Users of these guidelines shall define the vertical and lateral limits of the CO₂ plume in the geological storage site based on the expected distribution of the CO₂ plume as it stabilizes over the long term (see below).

The subsurface boundary shall also include components within the storage complex which aid retention of CO₂, such as secondary storage zones. It shall also include surrounding domains that may be impacted by injection of CO₂ into the subsurface.

8.4 Calculation of GHG effects

In accordance with Equation 2, the downstream GHG effects arising from geological CO₂ storage are isolated and measured as follows:

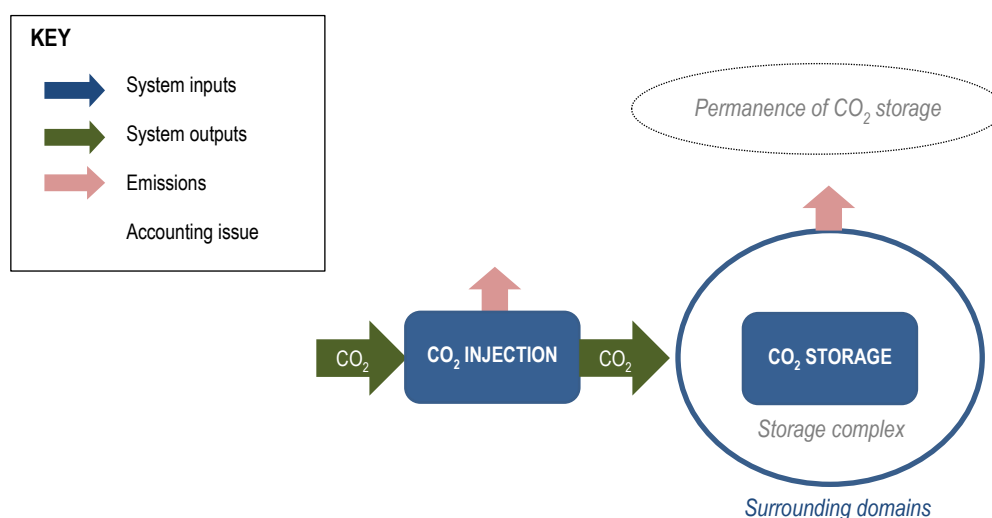
$$GHG\ Effect\ [P1\ only] \left(\frac{GHG}{ACT_{CCUS}} \right) = BL_{E,i,P1} - PE_{E,i,P1}[ONLY] \left[= \sum_{s=1}^n E_{i,s,ACT} \right]$$

[Equation 25]

Where, as Equation 2.

The GHG effects of capturing CO₂ – the parts in parenthesis in Equation 2 – are excluded in for illustrative purposes in Equation 25, but must be factored into the overall assessment alongside the baseline GHG intensity to provide a complete GHG assessment (as in Equation 2).

Figure 8.1 Schematic overview of CO₂ storage system components



8.4.1 Calculation of seepage emissions

Captured CO₂ sent for geological storage may be counted and reported as “not emitted” from the facility where it was captured (i.e., as an emission reduction activity) where various elements are in place that address concerns regarding the permanence, liability and carbon reversal risk presented by seepage.

The following elements provide assurances that help to confirm the permanence of storage and zero-seepage:

- Site selection:** appropriate methods must be used to characterise and model the performance of a selected geological storage site so as to demonstrate a low risk of seepage over the short, medium and long term.
- Monitoring:** technologies must be applied to monitor the location and behaviour of the CO₂ plume, storage complex and surrounding domains so that early warning of seepage is possible. Monitoring is also required to detect potential environmental impacts of uncontrolled CO₂ seepage or migration of the CO₂ into zones where its storage has not been authorised or could constitute trespass onto other subsurface properties.
- Liability and remediation:** liability should be appropriately allocated to an entity in the event that re-release of captured and stored CO₂ occurs due to seepage, and that obligations are in place to remediate any damages incurred due to seepage, both locally and in relation to carbon reversal.
- Long-term site stewardship:** that over the long-term, procedures should be put in place that maintain liability and remediation obligations over the geological CO₂ storage site.

A number of jurisdictions around the world have put in place regulatory measures to manage these aspects and thereby authorise CCS as an emission reduction technology.

In the EU and US, for example, facilities may report captured CO₂ as not emitted providing that it has been transported and stored in accordance with dedicated licensing regimes for geological storage of CO₂ in those regions, respectively: the EU Directive 2009/31/EC on geological storage of CO₂; and, the Safe Drinking Water Act Underground (SDWA) Injection Control (UIC) regime.

Similarly, in authorising CCS project activities under the Kyoto Protocol's CDM, dedicated rules ('modalities and procedures') were established for CCS project activities that impose similar requirements for project developers and host countries wishing to establish CCS projects under the mechanism (UNFCCC 2011).

Box 8.1 2006 IPCC Guidelines reporting requirements for geological CO₂ storage sites

Volume 2, Chapter 5 of the 2006 IPCC Guidelines require that national GHG inventory compilers, when reporting emissions from geological storage, undertake the following (summary):

1. Identify and document all geological storage operations in the jurisdiction.
2. Determine whether an adequate geological site characterization report has been produced for each storage site.
3. Determine whether the operator has assessed the potential for leakage at the storage site.
4. Determine whether each site has a suitable monitoring plan that includes:
 - a. Measurement of background fluxes of CO₂ (and if appropriate CH₄) around and over the storage site.
 - b. Continuous measurement of the mass of CO₂ injected.
 - c. Determination of any CO₂ emissions from the injection system.
 - d. Monitoring to determine any CO₂ (and if appropriate CH₄) fluxes through the seabed or ground surface, including where appropriate through wells and water sources such as springs. Periodic investigations of the entire site, and any additional area below which monitoring, and modelling suggests CO₂ is distributed, should be made to detect any unpredicted leaks.
 - e. Post-injection Monitoring. Once observations indicate that the CO₂ is approaching its predicted long-term distribution within the reservoir and there is agreement between the models of CO₂ distribution and measurements made in accordance with the monitoring plan, it may be appropriate to decrease the frequency of (or discontinue) monitoring. Monitoring may need to be resumed if the storage site is affected by unexpected events, for example seismic events
 - f. Incorporating improvements in monitoring techniques/technologies over time.
 - g. Periodic verification of emissions estimates.Continuous monitoring of the injection pressure and periodic monitoring of the distribution of CO₂ in the subsurface is also noted to be useful as part of the monitoring plan.
5. Collect and verify annual emissions from each site.

These obligations may be fulfilled by a national regulator of geological storage sites and reported to the inventory compiler, if one exists. If not, then the inventory compiler must ensure that these requirements are fulfilled. The post-injection monitoring requirements can provide a basis for ceasing monitoring, and, where allowable under national laws, the end of liability for the site operator and the passing of site ownership back to the host country government.

At a national level, countries wishing to report emissions reduction arising from CCS in national inventory reports or biennial update reports to the UNFCCC – and by extension, progress in achieving nationally determined contributions (NDCs) under the Paris Agreement – must follow Volume 2, Chapter 5 of the 2006 IPCC Guidelines (IPCC 2006), as summarised above (Box 8.1).

Procedures are set out below (Section 8.6) that implement similar requirement as described, drawing primarily on the CDM modalities and procedures.

8.4.2 Calculations for CO₂-enhanced oil recovery operations

Users performing a GHG assessment of CO₂-EOR operations shall follow methods set out in Section 7.

In addition, risks relating to permanence, seepage and carbon reversal shall be addressed following Section 8.6.4.

8.5 Baseline emissions

The baseline emissions for geological CO₂ storage activities ($BL_{E,i,P1}$) shall equal zero (see Section 5.3.1).

8.6 Activity emissions

Activity emissions consist of the emissions attributable to the CO₂ injection and geological storage facility. The main emissions sources that must be quantified within these facilities are described above (Section 8.3). Methods to calculate different emission sources are set out below.

8.6.1 Fugitive emissions (non-seepage)

Losses of CO₂ and resultant emissions to atmosphere can occur from leaking vessels and pipework and venting from CO₂ injection facilities.

Emissions can be estimated using a mass balance across the facility as follows:

$$CO_2 \text{ storage: fugitive emissions } (E_{i,S,ACT(FUG)}) = \frac{U_{CO_2,t} - INJ_{CO_2,t}}{INJ_{CO_2,t}}$$

[Equation 26]

Where,

$$\begin{aligned} U_{CO_2} &= CO_2 \text{ bought-in for storage over period } t (= T_{OUT} \text{ in Equation 16; } tCO_2) \\ INJ_{CO_2} &= \text{Mass of } CO_2 \text{ injected into geological reservoir over period } t (tCO_2) \\ t &= \text{Relevant period of time (e.g., one calendar year)} \end{aligned}$$

The denominator in Equation 26 is the mass of CO₂ injected, since this is equivalent to the primary P1 product (or service) provided and is therefore the functional unit of analysis (i.e., tCO₂ injected and stored).

8.6.2 Combustion emissions

Emissions from onsite generation of heat and power for operating CO₂ injection operations can be calculated using the method in Equation 14, but normalised to the functional unit of analysis i.e., the tCO₂ injected and stored in the geological reservoir.

8.6.3 Bought-in electricity and heat

Emissions from bought-in heat and power can be calculated using the same method in Equation 14 and Equation 15, but normalised to the functional unit of analysis i.e., the tCO₂ injected and stored in the geological reservoir.

8.6.4 Seepage

Seepage of CO₂ from a geological storage site back to the atmosphere (or surface water and/or seawater in the case of CO₂ storage sites located under the seabed) can potentially occur at any time after injection commences. Seepage can arise as a consequence of subsurface processes occurring after injection such as diffusion (through cap rocks) and migration (along fault planes and fissures or through operational or abandoned wells).

All potential seepage emission sources must be effectively managed through appropriate site characterisation and selection, site management and site monitoring. Collectively, these activities support ongoing assumptions of zero-seepage emissions from the storage site.

Based on these requirements, users of these guidelines shall undertake:

- Storage site characterisation
- Storage site monitoring for management purposes
- Monitoring and quantification of seepage emissions (if detected during monitoring for management purposes)

Guidance on each is provided below.

Storage Site Characterisation

Users of these guidelines should apply the following steps to characterize the geological CO₂ complex during project planning:

Step 1: data and information collection, compilation and evaluation. This step shall involve the collection of sufficient data and information to characterize the geological CO₂ storage complex and determine potential seepage pathways. The collected data and information shall be evaluated in order to make a preliminary assessment of the site's storage capacity and to assess the viability of monitoring. The data and information shall be evaluated for its quality and, where required, new data shall be collected.

Step 2: characterization of the geological storage complex architecture and surrounding domain. This step shall involve the assessment of known and inferred structures within the injection formation(s) and caprock formation(s) that would act as barriers to, or facilitators of, the migration of injected CO₂ in the subsurface. Methods applied shall involve the compilation of [a] numerical three-dimensional static earth model(s) of the geological storage complex. The uncertainty associated with key parameters used to build the model shall be assessed. The model shall be used to characterise, *inter alia*:

1. The structure of the geological containment system;
2. All relevant geological properties of the injection formation(s);
3. The caprock formation(s) and overburden;
4. The fracture system;
5. The areal and vertical extent of the geological storage complex (e.g., the injection formation, the cap rock formation, overburden, secondary containment zones and surrounding domain);
6. The storage capacity in the injection formation(s);
7. The fluid distribution and physical properties;
8. Other relevant characteristics

Step 3: characterization of dynamic behaviour, sensitivity characterization and risk assessment.

This step shall involve an assessment of how the injected CO₂ can be expected to behave within the geological CO₂ storage site (injection formation), storage complex and surrounding domains, with a particular focus on the risk of seepage. This step shall utilize numerical dynamic modelling of the injected CO₂ using the static model developed in step 2 above to assess coupled processes (i.e., the interaction between each single process in the model), and, where possible, reactive processes (e.g., the interaction of injected CO₂ with *in situ* minerals in the numerical model), and short- and long-term simulations. Such numerical modelling shall be used to provide insight into the pressure and extent of CO₂ plume in the geological storage site over time, the risk of fracturing the caprock formation(s), the risk of activating faults, and the risk of seepage. Multiple simulations shall be conducted to identify the sensitivity of the assessments to assumptions made. The simulations carried out in this step shall form the basis for a risk and safety assessment (not covered in these guidelines).

Step 4: establishment of a site development and management plan. Drawing on steps 1-3 above, a site development and management plan shall be established. The plan shall address the proposed conditions of use for the geological CO₂ storage site and include, *inter alia*, information relating to the following:

1. The preparation of the site;
2. Well construction, such as materials and techniques used, and the location, trajectory and depth of the well;
3. Injection rates and the maximum allowable near-wellbore pressure;
4. Operating and maintenance programmes and protocols;
5. The timing and management of the closure phase of the proposed CCS project, including site closure and related activities.

Results from steps 1 to 3 should be documented in a **Geological Storage Site Characterisation Report**. Results from step 4 should be documented in a **Site Development and Management Plan**.

Monitoring shall be carried out to support ongoing assessment of the validity of *ex ante* site characterisation in order to ensure the site development plan is being adhered to, and to detect early signs of irregularities and the risk of seepage (Section 8.8.1). Where seepage is detected during operations, it shall be quantified using monitoring methods described below (Section 8.8.2).

8.7 Validity of the baseline over time

Zero baseline emissions shall be assumed throughout the life time and beyond the end of the life of the project.

8.8 Data and monitoring

Table 8.1 below outlines data collection and monitoring requirements for the compilation of both *ex ante* and *ex post* estimates of GHG emissions from CO₂ storage as needed to complete this module.

Results of analysis can be used to estimate the activity emissions for application in Equation 2.

Table 8.1 Data needed to estimate GHG effects from CO₂ injection and storage

Factor	Desk-based GHG assessment (<i>ex ante</i>)	Monitoring and <i>ex post</i> GHG assessment
$E_{i,ACT(FUG)}$	Assumed as zero	Based on mass balance method set out in Equation 26
$E_{i,ACT(SEEP)}$	Assumed as zero	Based on monitoring method set out in Equation 27
$U_{CO_2,t}$	Estimated mass of CO ₂ to be injected at the CO ₂ storage facility	Metering records of mass of CO ₂ delivered to injection facility
$INJ_{CO_2,t}$	Estimated mass of CO ₂ to be injected at the CO ₂ storage facility	Metering records of mass of CO ₂ injected at wellhead(s)
$NCV_{P1,z}$	Assumed energy content of fuels used at the CO ₂ storage facility.	Records of facility operator providing heat and power.
$EF_{P1,z}$	Published emissions factors for relevant fuels	Same as <i>ex ante</i> assumptions
$MWh_{P1,t}$	Engineering design specifications for electricity consumption in the CO ₂ storage facility. Assumed source of electricity.	Metered imports of electrical energy
$EF_{GRID,t}$	Emissions factor for electricity grid in planned location of CO ₂ storage facility.	Annual emissions data and output produced by the grid system operator and/or reported average grid emission factor

In addition, the following monitoring requirements shall be implemented.

8.8.1 Storage Site monitoring for management purposes

The **Geological Storage Site Characterisation Report** and **Site Development and Management Plans** shall determine the following prior to implementation of the geological CO₂ storage activity:

- Conditions of use.** Methods of operation of the storage complex, setting down certain conditions such as maximums of pressure across the injection formation, caprock and in the surrounding domain. Monitoring shall be used to measure maximums of injection pressure and the maximum extent of the pressure front around the CO₂ plume and across the geological CO₂ storage complex and surrounding domains.
- CO₂ migration analysis.** Comparison of the predicted behaviour of CO₂ plume in the dynamic model (Step 3 above) with the monitored behaviour of the CO₂ plume after injection starts (“history-matching”);
- Geological storage site architecture analysis.** Analysis of key features within the geological CO₂ storage site architecture and surrounding domain that can potentially affect CO₂ storage security and seepage (e.g., faults, fractures, fissures, wells);

A subsurface monitoring plan shall be designed to support these objectives.

Monitoring shall support the determination of seepage, or zero-seepage, based on the following.

Conditions of use

Pressure in the injection formation (e.g., well bottom pressure; well annulus pressure) shall be monitored and in order to avoid conditions where pressure levels exceed limits that could induce the pressure driven processes that can affect storage security and seepage risk.

If monitoring shows that prescribed maximum operational pressure limits are exceeded, CO₂ injection should cease. Injection of CO₂ should not commence until pressure levels in the injection formation reduces below acceptable levels.

CO₂ migration analysis

Images of the geological storage site and CO₂ plume shall be periodically produced in order to provide information regarding the position and migration behaviour of the injected CO₂. Results can support reviews of the static and dynamic Earth model and potential revisions, and revisions to the delineated subsurface boundaries (“history matching”).

History matching shall be used to confirm that there is agreement between the numerical modelling of the CO₂ plume distribution in the geological storage site and the monitored behaviour of the CO₂ plume.

Where monitoring of CO₂ migration does not indicate any significant deviations to predicted behaviour, storage can be assumed to be operating satisfactorily. Increasing convergence between predictions and observations over time suggests a high-level of understanding of the subsurface, providing assurance over short, medium and long-term predictions of storage security (i.e., permanence).

If the results of analysis suggest that insufficient coverage is achieved in the monitoring plan design (e.g., gaps in knowledge regarding the subsurface project boundaries), the subsurface monitoring plan should be updated with new techniques and locations.

Detection of CO₂ at or beyond the maximums of the predefined subsurface upper vertical boundary (i.e., migration of CO₂ into the caprock formation) and/or lateral boundary at a given time shall be considered as a significant deviation, and the procedures outlined below must be followed (*Detection of significant deviations or evidence of seepage*).

If differences between observed and predicted behaviour are apparent during history matching with respect to the following:

- CO₂ migration direction is significantly different from the predicted lateral and or vertical direction;
- CO₂ migration rates away from well(s) annulus/annuli through the formation significantly exceed those predicted in modelling,

And where any combination of the above is considered to pose a risk of CO₂ migrating out of the predefined subsurface assessment boundary, this shall be considered as a significant deviation and the procedures defined below must be followed (*Detection of significant deviations or evidence of seepage*).

Geological storage site architecture

Monitoring shall be used to provide early signs of significant deviations within and outside of the boundaries of geological storage site as defined during geological storage site characterisation, including identified potential migration and seepage pathways. Examples include micro-seismic measurements in fault planes or fissures that could potentially be reactivated by CO₂ storage operations.

Where monitoring of features within the geological storage site does not indicate any significant deviations, storage can be assumed to be operating satisfactorily (subject to information gathered using other monitoring methods).

By default, a significant deviation is considered to be circumstances where there is a greater than 10% deviation between background measurements of conditions before injection and observed conditions as determined during monitoring. Users may propose a different deviation limit for any specific subsurface monitoring technique, where such a choice can be fully justified.

Where deviations between observed and predicted behaviour occurs, further investigations should be undertaken to determine the source of the deviation, and whether it poses a seepage risk.

Where a significant deviation is detected, the procedures below must be followed (*Detection of significant deviations or evidence of seepage*).

If the results of monitoring and analysis suggest that insufficient coverage is achieved in the present monitoring plan design (i.e., lack of information on key subsurface features in the geological storage site or surrounding domain), the subsurface monitoring plan should be updated with new techniques and locations.

Detection of significant deviations or evidence of seepage

In the event that significant deviations in the geological CO₂ storage site are observed in:

- The conditions of use of the site;
- During CO₂ migration analysis and history matching; and/or,
- Through monitoring of key features in the geological storage site architecture;

The site operator should cease CO₂ injection and make further investigations.

Investigations may lead to a revision of the Geological Storage Site Characterisation Report and Site Development and Management Plan, revision of the subsurface boundary, and updates to the monitoring plan etc. prior to recommencing CO₂ injection if deemed safe.

8.8.2 Storage Site monitoring for quantification of seepage emissions

If any monitoring technique detects evidence of seepage, the level of emissions should be calculated as follows:

$$E_{i,ACT[SEEP],t} = \frac{[\sum_k S_{FLX,k,t} \times S_{d,k,t} \times S_{k,AREA}] \times 10^3}{P1_{INJ,CO2,t}}$$

[Equation 27]

Where;

- $E_{i,ACT[SEEP]}$ = Seepage emissions in period t (tCO_2)
 $S_{FLX,k,t}$ = Flux rate of seepage source k in period t ($kgCO_2e/m^2 d^{-1}$).
 $S_{d,k,y}$ = Duration (days) that seepage source k is estimated to have been occurring in period t
 $S_{k,AREA}$ = the area over which the seepage from source k has been measured (m^2)
 $P1_{INJ,CO2}$ = Mass of CO_2 injected into geological reservoir over period t (tCO_2)
 t = Relevant period of time (e.g., one calendar year)

The duration of seepage ($S_{d,k,y}$) shall be determined as follows:

$$S_{d,k,y} = T_{START} - T_{END}$$

[Equation 28]

Where;

- T_{START} = One of the following dates:
1. the last date when the monitoring showed no evidence of seepage from the identified emission source. This may be up to one calendar year, or
2. the date the CO_2 injection started, when there is no available evidence to show that no seepage was previously detected, or
3. other evidence which may reasonably be used
 T_{END} = The date by which remedial measures have been taken and seepage can no longer be detected

A specific seepage event for any geological storage site will need careful consideration of the most appropriate technologies and means to identify the emission pathway and source, estimate the flux rate, the areal extent of the seepage zone, and to determine its duration.

These guidelines do not provide any procedures or methods for handling carbon reversal, long-term liability and site stewardship. Methods for remediating for damage to local or global climate impacts depend on jurisdiction- or scheme-specific requirements. Liability and long term stewardship depend on the specific laws applicable in the jurisdiction where the geological CO_2 storage site is located.

9 MEASUREMENT, REPORTING AND VERIFICATION

A wide variety of measurement techniques (metering flows, energy consumption etc.) must be applied to operational projects implementing these guidelines. Many of these techniques are well-established and do not present significant barriers to implementation.

9.1 Uncertainty

Uncertainty in monitoring data is a statistical estimate of the spread of individual results from the mean value, accounting for both systematic and random errors. It is established by repeating measurements so as to derive the standard deviation for a given value, which for a normal (binomial) distributed set of values provides the basis for determining the confidence limits for results. At a 95% confidence limit for normally distributed data, 95% of results will fall within 2 standard deviations of the mean.

The EU's GHG emissions trading scheme Monitoring and Reporting Regulation (European Commission, 2018) defines uncertainty as:

'uncertainty' means a parameter, associated with the result of the determination of a quantity, that characterises the dispersion of the values that could reasonably be attributed to the particular quantity, including the effects of systematic as well as of random factors and expressed in per cent and describes a confidence interval around the mean value comprising 95 % of inferred values taking into account any asymmetry of the distribution of values.

In simple terms, the calculated uncertainty provides an estimate of overall spread of an individual result in a dataset within an upper and lower range (\pm ; or confidence limits) of the average calculated value from the dataset.

In emissions accounting terms, two important components must be considered

- Measurement of uncertainty: how to calculate the uncertainty for a given dataset
- Maximum permissible levels of uncertainty: what is acceptable to the regulator?

Users of these guidelines shall calculate the uncertainty using recognised methods applied in various jurisdictions (e.g., under the EU's GHG emissions trading scheme).

Guidance from local regulators shall be sought to determine maximum permissible levels of uncertainty in reported data.

9.2 Reporting

No specific reporting template is provided for reporting the results of analysis compiled following these guidelines. Since the guidelines may be used for different purposes, both *ex ante* and *ex post*, different approaches may be adopted depending on the objective of the analysis.

Results of analyses compiled following these guidelines shall be reported in ways consistent with the principles outlined in Section 3.

9.2.1 Comparative assertions and making claims

ISO14040 defines a comparative assertion as an environmental claim regarding the superiority or equivalence of one product versus a competing product that performs the same function. The outcome of applying the CCU module (Sections 6 and 7) of these guidelines inherently results in such product comparisons.

Users shall therefore follow the guidance in ISO14040 when seeking to make comparative assertions derived from applying these guidelines to make environmental claims regarding their product. These include the need to ensure information provided is accurate, verifiable, relevant and non-deceptive. They shall also indicate sources of uncertainty within such comparisons (Section 9.1).

Where results are intended to be used to make public claims regarding the GHG benefits of a specific CO₂-derived product, process or technology, then ISO14040 requires additional steps be carried out. This shall be based on undertaking an impacts assessment of the results, and a critical review of the findings by a panel of interested parties according to guidance set out in the standard.

9.3 Verification

Users may wish to have the results of analysis and monitoring compiled following these guidelines verified by third party expert verifiers.

9.4 Linking to national greenhouse gas inventory compilation and reports

Reported results of *ex post* analysis compiled following these guidelines may be suitable for use in National Greenhouse Gas Emissions and National Inventory Reports (NIRs) under the UNFCCC.

Administrators responsible for compiling NIRs shall ensure that they are satisfied and have a clear understanding of the methods employed before using such results. Particular attention must be paid to ensure any reported emissions and potential emission reductions are not counted elsewhere in the NIR.

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Annex A – CO₂ benefit factor (precalculated)

The table below sets out some example CO₂ benefit factors for use in Equation 2 of the guidelines. They have been calculated according to secondary data published from a range of sources, as summarised further below. Users may elect to adopt values presented here when making an assessment of GHG effects. The use of these pre-calculated factors should be stated in any results.

		CO ₂ source plant					
		Biomass + capture	IGCC + capture	NGCC + capture	PC supercritical + capture	Supercritical 2 + capture	Ultra-supercritical + capture
Reference plant	Biomass (or other RE)	0.99	-0.17	-0.11	-0.16	-0.16	-0.16
	IGCC	2.15	0.79	1.93	0.59	0.61	0.75
	NGCC	1.53	0.27	0.83	0.18	0.19	0.26
	PC supercritical	2.23	0.86	2.07	0.64	0.66	0.82
	Supercritical 2	2.22	0.04	2.06	0.64	0.66	0.81
	Ultra-supercritical	2.08	0.73	1.80	0.54	0.56	0.70
	Biomass + capture	0.00	-1.00	-1.16	-0.81	-0.82	-0.94
	IGCC + capture	1.20	0.00	0.25	-0.03	-0.02	0.01
	NGCC + capture	1.06	-0.12	0.00	-0.12	-0.12	-0.11
	PC supercritical + capture	1.24	0.04	0.33	0.00	0.01	0.04
	Supercritical 2 + capture	1.23	0.03	0.31	-0.01	0.00	0.03
	Ultra-supercritical + capture	1.19	-0.01	0.24	-0.03	-0.03	0.00
	CO ₂ source plant	Ammonia + capture	Cement + capture	Steel mill + capture	DAC (100% renewable)	DAC (natural gas)	DAC (coal)
Reference plant	Ammonia	Cement	Steel mill				
Benefit factor	0.94	0.67	0.84	0.54	0.30	0.13	

Notes:

IGCC = Integrated coal gasification combined cycle fired power plant

NGCC = Natural gas combined cycle power plant

PC = Pulverised coal (sub-critical)

DAC = Direct air capture. DAC CO₂ Capture benefit factor calculated using different grid electricity intensity assumptions as follows: renewables (0 tCO₂/MWh); natural gas (0.488 tCO₂/MWh); coal (0.846 tCO₂/MWh)

Area	Item	Sources of Information
Capture and Reference Capture Plant type	Power plants	GCCSI (2011); McKinsey & Co. (2008)
	Biomass power plants	ETI (2012)
	Iron and Steel	IEA GHG (2013)
	Cement	IEA GHG (2008a); IEA (2008)
	Ammonia (high purity CO ₂)	IEA GHG (2008b); IFA (2009)
	Direct air capture	Baciacchi (2006); APS (2011)
	Others	IPCC (2006)
Upstream Fuel Emissions	Natural gas	UNFCC (2012)
	Coal	UNFCC (2012)
	Biomass	AECOM (2010)
	Petroleum Coke	Moretti <i>et al</i> (2017)

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