Carbon Capture and Storage Energy Attribute Certificates

A Standard and Guidance for Energy Tracking Registries

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Preface

This document has been prepared by Iain Kaplan and Gustaf Michaelsen of The NorthBridge Group, an economic and strategic consulting company serving the electric and natural gas industries. The views expressed within this paper are solely the responsibility of the authors.

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1 Executive Summary

Many experts agree that carbon capture and storage (CCS) will play a meaningful role in achieving ambitious climate goals. Although post-combustion carbon capture and storage has been implemented at select power plants, as of yet there is no standard approach for the issuance, tracking, and retirement of energy attribute certificates (EACs) that reflect the environmental characteristics of electricity generated from these projects. This document proposes a standard for CCS EACs.

A verified instrument conveying the emissions profile of CCS-backed electric supply can facilitate a consumer's claim to low-carbon, firm, dispatchable electricity in its Scope 2 emissions inventory under the World Resources Institute and World Business Council for Sustainable Development's Greenhouse Gas Corporate Accounting Protocol. For energy tracking registries (Registries), a standardized approach to calculate emissions across all CCS projects at electric generating units is needed to issue credible certificates to back the emissions claims that attribute holders wish to make. An EAC that meets both groups' needs will promote market confidence, reduce the risk of non-standardized market instruments, and encourage CCS adoption.

The standard articulated in the following sections serves two purposes. First, it is designed to provide detailed, prescriptive guidance on calculation methodologies, requirements, and decision points for Registries who may consider issuing CCS EACs. Second, it aims to offer broader context by exploring the rationale behind each element included in the standard to foster transparency and promote market confidence in its approach to carbon accounting at CCS-equipped electric generating units. As such, it can be read as an instruction manual, as a policy document, or both, depending on the perspective of the reader.

Key elements discussed in the following sections include:

- *Structure of the Attribute*: One EAC is issued for each megawatt-hour of generation. The EAC is minted with an associated emission rate measured in pounds of carbon dioxide equivalent (CO_2e) per megawatt-hour. When retired, the attribute holder may claim the pounds of CO_2e listed on the attribute in its market-based Scope 2 inventory. The emission rate will reflect the performance of the project and will vary between EACs issued from a given project, as well as among EACs from different projects.

- *Eligibility:* The calculation methodology is applicable to multiple fuel types, generation technologies, and post-capture CO_2 pathways. Registries may elect to issue EACs only to certain fuel types or post-capture pathways.

- *Processes Considered*: The emission rate calculation methodology includes emissions from electricity generation, CO_2 capture, CO_2 transport, and CO_2 storage so that the EAC represents emissions from all activities required to ensure permanent CO_2 storage. Emissions from on-site activities as well as purchased energy are included. Though the standard acknowledges the potential for the EAC to reflect the carbon intensity of upstream fuel supply, it does not propose how to do so or recommend doing so at this time.

- *Granularity*: The issuance of hourly certificates is encouraged.

- *Applicability*: This standard relies on the rigor of U.S. permitting, verification, and monitoring standards, but may be applied in other areas that impose similarly stringent requirements.

- *Monitoring and Verification*: All project data is subject to independent third-party verification. There is a requirement to submit Monitoring and Reporting Plans, which can be met through other regulatory documentation.

- *Leakage*: To protect an attribute holder's emissions claims against the potential impact of post-injection leakage, all projects will be required to hold some form of self-insurance. The standard recommends a menu of options that Registries may offer and from which projects can choose, such as private insurance, credit reserves or holdbacks, and issuing EACs with built-in leakage estimates.

This document offers a robust and credible standard for the issuance and use of CCS EACs. As the principles in this document are implemented, Registries may find that changes or adjustments are required. The authors anticipate that this standard may evolve over time, especially as the Greenhouse Gas Protocol Update Process progresses or as additional guidance on the treatment of CCS-equipped electricity generating units is disseminated.

2 Introduction

2.1 Background on Carbon Capture at Electricity Generators

The 2015 Paris Agreement set a goal of limiting global average temperature increases to 1.5 degrees Celsius above pre-industrial levels and emphasized the "importance of fully realizing technology development and transfer in order to improve resilience to climate change and to reduce greenhouse gas emissions."[1] Decarbonization of the electricity sector takes on outsized importance, as tapping into a low-carbon electric grid is considered the most efficient way to decarbonize other sectors like transportation and manufacturing.

Significant strides towards a decarbonized electric grid have been made on account of the proliferation of state renewable energy portfolio standards and clean energy buyers who have sought to voluntarily address their greenhouse gas (GHG) emissions by purchasing renewable or carbon-free electricity. Such mandates and voluntary purchases have sent strong demand signals for the development of renewables. While this is a highly constructive decarbonizing mechanism, more must be done; a gap exists between what the international community has achieved and what must be achieved to meet the Paris Agreement goals.[2] Experts recognize the importance of producing more low- and zero-carbon electricity around-the-clock to close the gap and realize these ambitions goals.[3]

Projects that prevent the release into the atmosphere of carbon dioxide (CO_2) from fossil-fired generating units, and instead sequester or utilize these GHGs, are a promising approach to further decarbonize the electric sector. Carbon capture and storage (CCS)[4] can be applied to existing fossil fuel-fired generating units (through retrofits), incorporated in the design of new generating units, and spur the development of innovative technologies that may be especially well-suited for low- or zero-carbon energy generation. Although these facilities are not expected to capture all potential carbon emissions, electric generating

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[1] Paris Agreement, FCCC/CP/2015/L.9/Rev.1, Article 10.1.

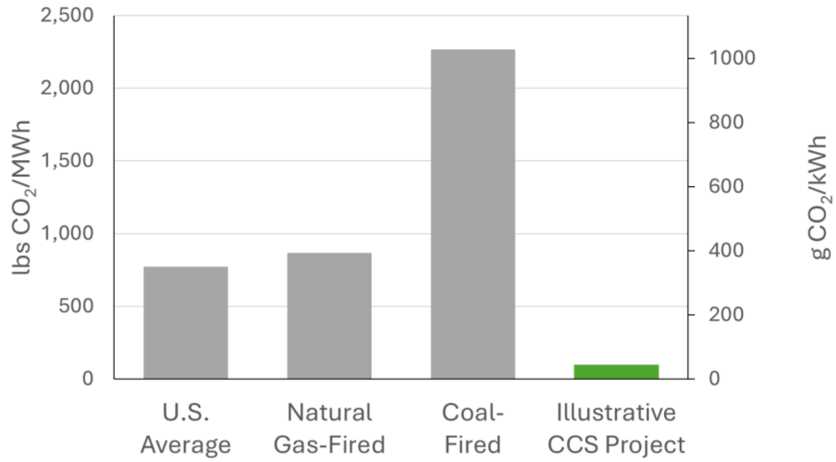
[2] Emissions Gap Report 2022, United Nations Environment Programme, October 2022.

[3] See Denholm et al., *Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035*, National Renewable Energy Laboratory, 2022; Intergovernmental Panel on Climate Change, *Mitigation of Climate Change*, 2022; European Commission, *Europe's 2040 climate target and path to climate neutrality by 2050 building a sustainable, just and prosperous society*, 2024; California Air Resources Board, *2022 Scoping Plan for Achieving Carbon Neutrality*, 2022.

[4] The acronym CCS can refer to carbon capture and storage or carbon capture and sequestration. The acronym CCUS, referring to carbon capture, utilization, and storage, is also often used. These acronyms are often used interchangeably, and the terms storage and sequestration are often used interchangeably. In this document, "sequestration" will refer specifically to storage of carbon in geological formations. The term "storage" will be used more generally and may encompass utilization.

units that deploy CCS will have significantly lower carbon emissions than their unabated counterparts, as illustrated in Figure 1 below.

Figure 1: Indicative CO_2 Emission Rates from Various Electric Generating Units[5]



Because carbon capture and disposal entail significant costs, CCS projects will not advance without regulatory requirements or compensation for their emissions reductions. The U.S. Federal 45Q tax credit provides up to $85 per metric ton (referred to hereafter as ton) of qualified stored CO_2,[6] which makes a significant contribution towards project economics. To date, this has not proven sufficient to spur widespread adoption of CCS in the absence of additional support from clean energy offtakers.

For many electricity consumers, CCS-equipped generation is an appealing supply option given its low-carbon emissions, round-the-clock output profile, and potential for deployment at large scale. These customers may be willing to pay a premium for electricity generated by facilities using CCS. This premium, possibly coupled with 45Q tax credits in the U.S. or other low carbon initiatives globally, may be sufficient to enable CCS project viability. However, project developers and clean energy offtakers must have a means to convey and claim the benefits of this low-carbon electricity.

2.2 Overview of GHG Protocol Emissions Reporting

Entities reporting emissions pursuant to the World Resources Institute (WRI) and World Business Council for Sustainable Development (WBCSD)'s Greenhouse Gas Corporate Accounting Protocol (GHG Protocol) separate their emissions into three scopes based on operational boundaries. GHG emissions that occur from sources that are directly

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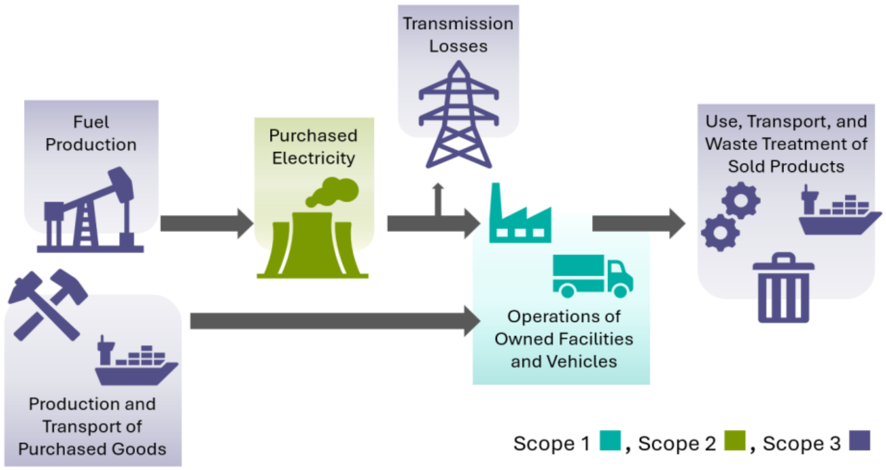
[5] U.S. Environmental Protection Agency, *eGRID with 2023 Data, Revision 1*, and U.S. Energy Information Administration, *Electric Power Monthly*, February 2025. CCS figures are illustrative.

[6] The amount of the credit is subject to an inflation adjustment multiplier.

owned or controlled by a company are included in Scope 1. Emissions from the purchase of electricity and heat products are included in Scope 2. Scope 3 includes all other emissions that indirectly occur as a consequence of an entity's activities. See Figure 2 for an illustrative example of an entity's emissions inventory by Scope.

Figure 2: Overview of Scopes in GHG Protocol



Electricity consumers often seek ways to reduce their Scope 2 emissions by supporting low- or zero-carbon energy generation. It is important to note that not all aspects of purchased electricity generation are included in an entity's Scope 2 inventory; emissions from the production of fuel used to power an electric generating unit, the construction of power infrastructure, and transmission and distribution losses all fall into that entity's Scope 3 inventory.

2.3 The Role of Environmental Attributes

Standards exist today for issuing environmental attributes for carbon reductions or removals at CCS projects.[7] These standards are typically designed to create an emissions offset denominated in tons of CO_2 equivalent emissions (CO_2e) mitigated. For the specific application of CCS contemplated in this document – carbon captured from electric generating units – attribute holders may look instead to directly apply a low carbon intensity to their Scope 2 emissions.

Energy Attribute Certificates (EACs) are commonly used to support claims about the GHG emissions associated with a consumer's electricity consumption. EACs can be used

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[7] For example, see ACR, *Methodology for the Quantification, Monitoring, Reporting, and Verification of Greenhouse Gas Emission Reductions and Removals from Carbon Capture and Storage Projects*, v. 1.1; Verified Carbon Standards, *VM0049 Carbon Capture and Storage*, v1.0; Alberta Environment and Protected Areas, *Quantification Protocol for CO2 Capture and Permanent Geologic Sequestration*, v 2.0.

by electricity customers to report emissions (or the absence of emissions) associated with their electricity consumption when retired by the bearer, with one EAC representing one megawatt-hour (MWh) of electricity generation from a specific source. Under the GHG Protocol, these certificates support customer claims for their market-based Scope 2 emissions. A common example is a renewable energy certificate (REC), which may be issued to convey the carbon-free characteristics of solar, wind, or other renewable energy sources in Scope 2 accounting.

The first environmental attribute markets for electricity were established in the 1990s and early 2000s in the U.S. and the European Union.[8] These markets serve a variety of energy buyers and electric service providers with certificates to meet mandatory portfolio standards and consumer-driven demand. Millions of RECs and Zero Emissions Certificates (ZECs) are issued to generators across the U.S. every year. In 2023, 319 million MWh of RECs were procured through voluntary power markets.[9] Outside of the U.S., similar certificates such as I-RECs and Guarantees of Origin are used to trade environmental attributes.

EACs are not limited to renewable electricity sources; energy tracking registries (referred to hereafter as Registries) also can, and do, issue EACs for nuclear generation, natural gas generation from fuel blending at historically coal-fired facilities, generation from alternative fuel sources (such as waste coal, biomass, or others).

Regardless of the electric generating unit backing the certificate, the EAC is the basis of conveying the emissions or other characteristics of its electricity generation. Under market-based Scope 2 accounting, electricity consumers can make claims about the emissions associated with their electricity consumption by retiring EACs, whose attributes can be applied to the corresponding electricity consumption.

2.4 CCS EAC Working Group

Many parties at the frontier of electric sector decarbonization have identified the need for and value in creating a standard for issuing EACs for generation with CCS. A standardized EAC will promote market confidence, reduce the risk of non-uniform market instruments, and encourage CCS adoption.

To advance these efforts, The NorthBridge Group (NorthBridge), an economic and strategic consulting company that serves the electric industry, facilitated a working group of industry leaders and technical experts with participants representing Registries, electric generating unit owners and operators, carbon solutions providers, energy consumers, and

[8] NREL, *Emerging Markets for Renewable Energy Certificates: Opportunities and Challenges*, p. 7.
[9] NREL, *The State of the U.S. Voluntary Green Power Market (2023 Data)*, p. 2.

industry consultants.[10] Working group members included members of the Scope 2 Technical Working Group in the GHG Protocol Standards Update Process to inform and be informed by that group's efforts.

Between March and May 2025, the working group convened on several occasions to discuss issues such as eligibility requirements, the structure of an EAC for CCS, methods for quantifying emissions from CCS-equipped projects, best practices for verifying emissions and other reported data, criteria for ensuring the permanence of CO_2 storage, and guidelines for issuing, tracking, and retiring EACs.

In addition to facilitating this working group, NorthBridge engaged with a broader stakeholder group. First, beginning in February 2025 and through the initial drafting of this document, NorthBridge held ad hoc discussions with many interested parties to gain preliminary insights and gather feedback on the project scope. Second, after fielding revisions from the working group, a draft of this document was shared with a broad network in June and July 2025 to solicit feedback, which has been incorporated into this final document.

These workshops, discussions, and stakeholder outreach led to a robust discussion of the many considerations needed to ensure market confidence in an instrument designed to convey the attributes of CCS-equipped electricity generation. The guidance found in the following sections reflects these efforts.

2.5 Purpose of Document

This document presents a proposed standard that Registries can adopt to govern the issuance and retirement of Energy Attribute Certificates for electric generating units that implement carbon capture and storage. This document is meant to articulate a reasonable, workable protocol for Registries to follow and is tailored to the CCS and carbon emissions landscape at the time of its writing. EACs created under the guidance of this document are primarily designed to facilitate emissions claims made by the bearer pursuant to the GHG Protocol.

This standard considers the issuance of EACs associated with electric generating units that utilize some form of carbon capture. It uses U.S. regulations as a reference point; however, this standard and its guidance are applicable to markets outside the United States with similarly strong regulations, or to Registries that choose to impose such standards.

[10] Working group members included Stephen Lamm (Bloom Energy), Hannah Maertz (CleanCounts), Michelle Chang (Google), Adam Forni (Google), Devon Swezey (Google), Jonathan Wiens (Low Carbon Infrastructure), Tatjana Vujic (Novi Strategies), Iain Kaplan (NorthBridge), and Gustaf Michaelsen (NorthBridge).

The following sections propose required and recommended procedures for a Registry to follow, provide guidance on how to address common concerns about CCS to promote market confidence, and aim to articulate a consensus view of how to convey the environmental attributes associated with CCS projects at electric generating units.

The authors acknowledge that this is an initial standard. In time, other options or alternatives for issuing EACs for CCS may evolve, protocols for GHG reporting may change, and other considerations may become necessary when issuing an EAC to ensure its widespread acceptance. For example, the GHG Protocol Standards Update Process, especially the Scope 2 and Market Instruments Working Groups, may promulgate new practices or revised standards for emissions accounting. Nonetheless, this standard is designed to serve as a first step to facilitate the issuance of EACs for CCS and, in turn, accelerate the development of CCS projects. Further discussion of the future of this standard is found in Section 10.2.

3 Attribute Definition

3.1 Structure of Attribute

The environmental attributes of a CCS-equipped electric generating unit could be conveyed in many fashions. These options include:

Recommended Structure

- **<u>Conveying the megawatt-hours generated and the pounds-per-MWh emission rate associated with these megawatt-hours</u>:** A CCS EAC denominated in megawatt-hours would facilitate electricity customers' Scope 2 claims by allowing customers to match megawatt-hour-based certificates with their megawatt-hour electricity consumption. This structure is similar to RECs and other EACs, so it would benefit from buyers' familiarity. In this form, each EAC would be minted with a lbs-CO_2e-per-MWh rate[11] reflecting the emissions associated with the generation of that megawatt-hour. The emission rate on the EAC would differ between projects based on their respective performance, and would vary over time among attributes issued at a single project.

Alternative Structures Considered, but Not Pursued in this Standard

- **<u>Conveying that a share of electricity produced by the project is carbon-free</u>:** Attribute holders may desire an instrument that can be used to claim zero Scope 2 emissions. This approach would calculate a carbon-free electricity equivalent from electricity generated by CCS-equipped projects. Given that a portion of project emissions are uncaptured, the number of EACs issued would be less than the electric generating unit's net generation. For example, 100 megawatt-hours of generation could lead to the issuance of 90 EACs in this alternative.
- **<u>Conveying that the generation meets a prescribed level or standard of performance</u>:** To facilitate trading, buyers may demand a product with a standardized definition. For example, coal markets have several uniform products (Northern Appalachian coal, Central Appalachian coal, etc.) with a defined minimum or maximum heat content, sulfur content, and carbon content, among other specifications. Defining standards based a range of emission rates or capture percentages may eventually aid in the development of liquid markets for CCS EACs.

[11] This standard refers to the amount of CO_2e emissions associated with the generation of one megawatt-hour of electricity as the "emission rate". This may also be referred to as the carbon intensity of a megawatt-hour or as an emission factor. While expressed as a pounds-per-MWh emission rate in this document, it may be equivalently expressed in grams CO_2e per MWh.

- **<u>Conveying the megawatt-hours generated and the percent of carbon captured or stored</u>:** Attribute holders may be interested in knowing what percent of the carbon produced at an electric generating unit is captured or ultimately sequestered or utilized. Some states such as Michigan have adopted clean energy standards that treat a fossil-fired resource using CCS as an eligible resource if it achieves a certain capture rate. An attribute that includes a capture percentage would facilitate compliance with these standards.
- **<u>Conveying the tons of emissions reduced, removed, captured, or stored</u>:** Instruments issued through existing carbon credit markets are denominated in tons of emissions reduced. The environmental attribute ecosystem includes many carbon credit registries that verify a wide variety of applications, and carbon credit registries – such as American Carbon Registry and Verra – have defined methodologies for carbon capture. When these instruments are retired, they are reported alongside Scope 1, 2, or 3 emissions as a counterbalancing claim.[12] However, some electricity consumers may seek a way to directly claim lower Scope 2 emissions. A tons-based instrument bearing negative tons of emissions designed for use within Scope 2 and Scope 3 accounting could be considered.

Figure 3: Options Considered for Energy Attribute Certificate

Option	Low-Carbon MWh	Carbon-Free Equivalent MWh	Meets a Prescribed Standard	Percent of Carbon Captured or Stored	Tons Attribute
One EAC Represents:	1 MWh	1 MWh	1 MWh	1 MWh	1 ton
EACs Issued per MWh Generated with CCS	1	Less than 1	1, if standard is met, otherwise 0	1	N/A
CO_2e Emission Rate on EAC	(Non-zero) CO_2e rate	Zero CO_2e	CO_2e rate is within a defined range	N/A	N/A

This document provides guidance around issuing an EAC that bears an emission rate in lbs-CO_2e-per-MWh for each MWh of generation, as highlighted in Figure 3 above. While alternatives above may have merit, this initial standard is designed to articulate guidance on a single approach to promote standardization and market confidence. A Registry may consider including secondary, informational statistics on EACs related to the alternatives

[12] World Business Council for Sustainable Development and World Resources Institute, *The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard*, Revised Edition, p. 82.

above, however the primary (and required) attribute on the CCS EAC in this standard is the lbs-per-MWh emission rate.

This document does not contemplate defining a tiered hierarchy to be applied to CCS EACs; however, standards may emerge in time (with certifying bodies to define and endorse them) as the CCS EAC market matures. Because CCS projects are initially expected to proceed under a project sponsorship model, this document prioritizes an approach that facilitates emissions claims rather than an approach that facilitates trading through standard classes of CCS EACs.

3.2 Use of Attribute

The CCS EAC described in this document is designed to be a fungible instrument used to support Scope 2 claims for electricity consumers. When the attribute holder retires the EAC, it may claim the number of pounds of CO_2e from the numerator of the EAC's emission rate in its Scope 2 emissions accounting. This approach will leverage the widespread acceptance of megawatt-hour-based EACs and align with best practices under the Greenhouse Gas Protocol.

Figure 4, below, demonstrates the use of CCS EACs through three scenarios. In the first, a customer with five megawatt-hours of electricity consumption and no attributes uses a supplier- or grid-specific Scope 2 rate to calculate 4,500 lbs of Scope 2 emissions. In the second scenario, the customer receives five CCS EACs, each bearing a 100 lbs-per-MWh emission rate. The 100 lbs in the numerator of the emission rate are claimed for each corresponding megawatt-hour, leading to an inventory with 500 lbs of Scope 2 emissions. The third scenario illustrates how CCS EACs can be used in conjunction with other EACs such as RECs, leading to an inventory with 300 lbs of Scope 2 emissions.

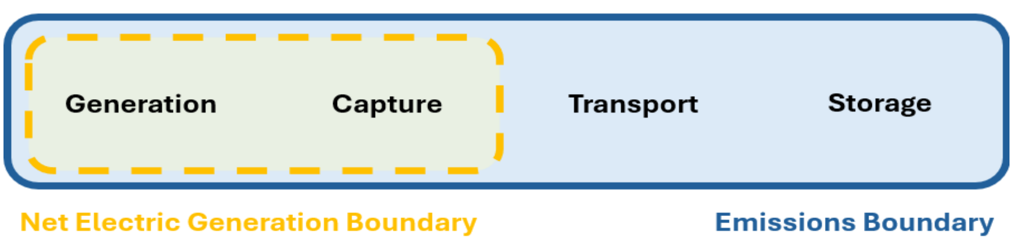
Figure 4: Illustrative Electricity Consumer Scope 2 Emissions

	Without EACs	***With 5 CCS EACs***	***With 3 CCS EACs and 2 RECs***
Electricity Consumption *(Each Square = 1 MWh)*			
Energy Attributes Certificates *(Each Square = 1 EAC)*	*None*		
Emission Rate (lbs/MWh) Applied to Each MWh	*900 900 900 900 900* Supplier or Grid rate	*100 100 100 100 100* EAC rate	*100 100 100 0 0* EAC rate
Scope 2 Emissions	4,500 lbs	500 lbs	300 lbs

3.3 Project Boundary

A CCS-equipped generation project must have a uniform, clearly defined boundary for data collection and calculation to produce an EAC that is equivalent across projects. The EAC should include all emissions and generation occurring within the project boundary. The major components within the project boundary include the generating units and systems for capture and compression, transport, and storage.

Figure 5: Project Boundary



Activities associated with the capture and permanent sequestration of carbon would not occur but for the electric power generation; they are a consequence of the generation of low-carbon electricity at CCS-equipped facilities and their resulting emissions must be reflected in associated EACs. Including capture, transport, and storage in the project boundary will also incentivize lower emissions in these components.

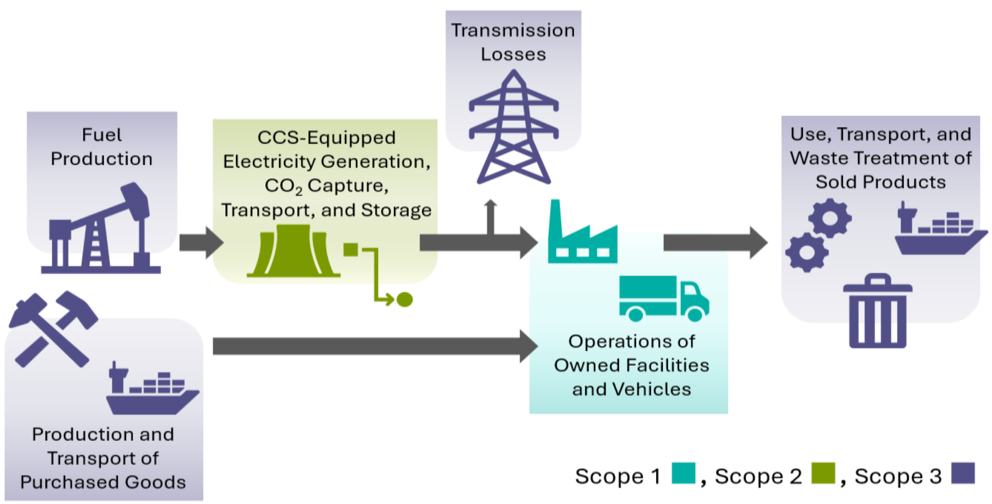
The project boundary is defined to include these components to ensure equivalence among CCS EACs. Projects may have design alternatives, such as the level of compression applied to captured CO_2 before versus after transport, that would materially impact the emission rate borne by the EAC if emissions associated with the transport and storage processes are not included; the EACs from a project that chooses to apply greater compression at the point of capture (which would either reduce net plant generation or incur emissions) should allow for similar claims to those that would be made with EACs from a project that instead chooses to apply greater compression at the point of storage.

The methodology will also include both "direct" and "indirect" emissions:

- Direct emissions are emissions measured at points within the project boundary.
- Indirect emissions are emissions associated with energy sources received by the project but whose emissions occur outside the ownership or control of the project (such as purchased electricity or steam).

This approach ensures equivalent treatment of projects that rely on varying degrees of on-site use of fossil fuels.

Figure 6: Project Boundary's Position Within an Entity's Broader GHG Inventory



Emissions associated with the production and transportation of fuels and the distribution of energy within a grid are excluded from the project boundary and from quantification of indirect emissions, as shown in Figure 6 above.[13] This is consistent with current Scope 2 and 3 guidance.[14] Similarly, electric transmission and distribution losses as well as emissions from the construction of power infrastructure are also excluded from the project boundary and from quantification of indirect emissions. Energy buyers may

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[13] Greater detail on the role that low carbon intensity fuels may play is included in Section 9.3.

[14] WRI, *GHG Protocol Scope 2 Guidance*, p.34

complete a separate life-cycle analysis that includes the upstream and downstream impacts of their power procurement if they wish.

In this way, the emissions that are not included in an entity's Scope 2 inventory are consistent across renewable, traditional thermal, and CCS-equipped generation. Emissions and power use associated with the capture, transport, and storage of CO_2 are unique to the CCS-equipped generation pathway and this standard includes them within the project boundary. If future Greenhouse Gas Protocol guidance determines that some or all of the capture, transport, and storage emissions for purchased electricity should be included in an inventory other than Scope 2, then the emissions conveyed on a CCS EAC should be allocated between the appropriate scopes.[15]

3.4 Registering Entity

As noted in the previous section, the CCS EAC will include measurements of carbon at several points in its journey from the electric generator to the storage point. Due to the many specialized project components, there may be two or more legal entities owning or operating equipment within the project boundary. Submitting all relevant data and documentation to support the issuance of an EAC will require coordination and cooperation between the owners and operators of each of the various project components.

This standard envisions having a single Registering Entity that registers the project with the Registry, completes all project documentation, submits project data, and ultimately receives EACs. Even if required documentation or data is sourced by another entity, the Registering Entity is responsible for its completion and submission. The Registering Entity and other entities involved in the project are assumed to have their own commercial arrangements that define which entity or entities receive title to EACs and under what terms.

3.5 Preventing Double Counting

To avoid double counting or double claiming, Registering Entities may not pursue carbon credits (or other environmental attributes) for the emissions captured and stored within the project boundary that are included in the calculation methodology and reflected in an EAC. Projects with upstream fuel impacts (which are outside the project boundary), such as bioenergy carbon capture storage (BECCS), may pursue carbon credits for these

[15] If necessary, each term of the calculation methodology presented in Section 5 may be assigned as relevant to Scope 2 or Scope 3, and the EAC may bear a Scope 2 emission rate and a Scope 3 emission rate.

upstream fuel impacts while separately pursuing EACs for the electricity generation, capture, transport and storage without being subject to double counting concerns.

Because the low-carbon attributes of CCS-equipped generation will be claimed by the entity that retires an EAC, no other electricity buyer should be able to claim these attributes for Scope 2 reporting purposes. The calculation of emission rates for grid power or the residual electricity mix should remove the generation and emissions from electric generating units receiving CCS EACs.

If any component of the calculation methodology described in Section 5 involves an entity that elects to pursue separate environmental attributes associated with its direct operations,[16] the Registering Entity must treat energy inputs from that entity as indirect emissions and demonstrate that it does not claim the benefit of those separately-claimed emissions reductions or attributes in its application of this standard's calculation methodology.[17]

Pursuing federal tax credits and/or avoiding state carbon taxes or penalties in addition to generating EACs under this methodology is not considered double counting.

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[16] E.g., if electric demand at a carbon injection site receives beneficial electrification credits under a Clean Energy Standard such as those enacted in Vermont or New Orleans or if a carbon services provider pursues offset credits for capturing emissions associated with its own production of steam used in post-combustion capture of a power generator's emissions.

[17] See Appendix C, Illustrative Example #6 for an example of this configuration.

4 Eligibility

4.1 Fuel Types

Carbon capture can be applied to post-combustion flue gas from many fuel sources — including natural gas, coal, and biomass — though the processes may differ. Similarly, the standard can be applied to pre-combustion or non-combustion carbon capture technologies just as for post-combustion technologies. Because the attribute structure contemplated in this standard is centered around reporting a lbs-per-MWh emission rate on each EAC, this approach is compatible with any fuel type deploying CCS.

Registries are welcome to consider fuel type restrictions at their discretion. For example, a Registry may determine that CCS applications at natural gas generators are likely to comprise the first phase of CCS adoption and choose to focus on applying the standards in this document to natural gas generation only for simplicity. Or, a Registry may determine that as a matter of policy it does not wish to issue EACs for CCS applications at coal-fired generators. Registries should designate the fuel used at the electric generating unit on their CCS EACs in anticipation of interest from attribute holders.

If a generator blends fuels such as hydrogen, renewable natural gas, or certified gas into its feedstock, the methodology in Section 5 will be compatible with these applications. Unique considerations for low carbon intensity fuels are discussed in Section 9.3.

4.2 Generation Technologies

At this time, this standard does not propose any restrictions based on the prime mover or generating technology of the project. This will allow novel technologies to pursue EACs without being at a disadvantage relative to existing technologies, which will encourage innovation.

Should a project utilize a novel technology or a unique engineering configuration of an existing technology, the project-specific Measurement Plan described in Section 7.2 will demonstrate how emissions associated with the project are metered, included within the framework of the methodology in Section 5, and appropriately calculated.

4.3 Post-Capture CO_2 Pathways

Once CO_2 is captured, it may follow one of several pathways:

- **Sequestration**: Permanent underground storage in geological formations, such as saline reservoirs.
- **Utilization, Enhanced Oil Recovery (EOR)**: Injected into oilfields to increase production.
- **Utilization, Enhanced Gas Recovery (EGR)**: Similar to EOR, CO_2 injections can facilitate additional natural gas extraction.
- **Utilization, Non-oil/non-gas utilization**: CO_2 can be used as an input in chemical processes, such as in the production of fertilizer, or otherwise combined or changed into another product.

For an initial application of this standard, Registries may elect to focus on permanent sequestration applications in Class VI wells permitted under the U.S. Environmental Protection Agency's (EPA) Underground Injection Control (UIC) program. This approach would leverage the extensive requirements already imposed on these wells to ensure safe and secure geologic storage, as Class VI wells are considered very likely to retain over 99% of stored CO_2 after 100 years and likely to retain over 99% of stored CO_2 after 1,000 years.[18]

EOR applications have a long history, and utilization is likely to remain a component of the CCS landscape in some form due to its widespread use in U.S. energy production. For these reasons, Registries may prefer not to place any restrictions on the end use of CCS projects receiving EACs. To the extent that there are any additional reporting requirements under the GHG Protocol related to utilization applications, such as reporting the emissions from the end use or transportation of utilization products, the entity claiming the attribute retains these obligations. To facilitate the buyer's complete greenhouse gas emissions accounting, the Registry should designate on each CCS EAC or otherwise make available to the buyer the CO_2 pathway reported by the Registering Entity (i.e., whether the captured CO_2 is associated with sequestration, EOR, EGR, another utilization pathway, or delivered to a system with multiple end uses).

[18] Intergovernmental Panel on Climate Change, *Carbon Dioxide Capture and Storage*, p.14. "Very likely" is defined as a probability between 90 and 99% and "Likely" is defined as a probability of 66 to 90%.
See also Alcalde, Juan, et al. *Estimating geological CO_2 storage security to deliver on climate mitigation*, Nature, 2018, which notes that "in a realistically well-regulated industry, with a moderate density of legacy wells, our program calculates a 50% probability that more than 98% of the injected CO_2 will remain trapped in the subsurface over 10,000 years."

5 Calculation Methodology

5.1 Project-Specific Calculation

This methodology for calculating an emission rate for CCS-equipped generating units can be applied to a broad range of project types. Because each project will be unique, a project-specific Measurement Plan is necessary to demonstrate compliance with these calculation guidelines. This will ensure that attributes adhering to this standard are consistent across varied project configurations. Section 7.2 provides more detail on the requirements for the Measurement Plan.

5.2 Overview of Methodology

This section outlines the components used to calculate the quantity of CCS EACs and their associated emission rate. Unlike other EACs that convey a zero-emission rate for Scope 2 emissions, the emission rate of CCS EACs issued across a given time period is dependent on the project's performance. This standard provides a methodology to measure that performance: the project's net electric output (calculated in Section 5.8) and its associated CO_2e emissions (calculated in Sections 5.4-5.7). Defined terms are rendered in *this style* and equations are numbered "Eq. X" at the right of the page. Examples of the application of this methodology to sample projects can be found in Appendix C.

The emission rate of a CCS EAC is defined as the ratio of CO_2e emissions from generation and capture (G&C), transport (T), and storage (S) to net electric output:

$$\frac{CO_2e\ Emissions_{G\&C} + CO_2e\ Emissions_{T} + CO_2e\ Emissions_{S}}{Net\ MWh} \quad \text{(Eq. 1)}$$

Where:

$$CO_2e\ Emissions_{G\&C} = CO_2e\ Generator + CO_2e\ Auxiliary_{C} + CO_2e\ Purchased_{C} - CO_2\ Transfer_{T} \quad \text{(Eq. 2)}$$

$$CO_2e\ Emissions_{T} = CO_2e\ Transfer_{T} + CO_2e\ Equipment_{T} + CO_2e\ Purchased_{T} - CO_2\ Transfer_{S} \quad \text{(Eq. 3)}$$

$$CO_2e\ Emissions_S = CO_2e\ Transfers_S + CO_2e\ Equipment_S + CO_2e\ Purchased_S - CO_2\ Transfer_I + CO_2e\ Fugitive_S \quad \text{(Eq. 4)}$$

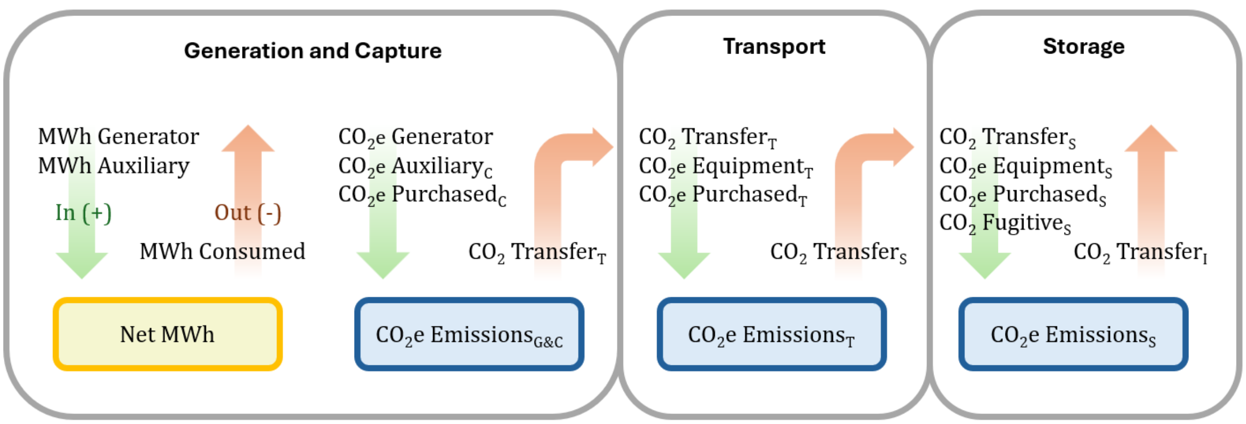
$$Net\ MWh = Net\ MWh_{elec} + Net\ MWh_{Cogen} \quad \text{(Eq. 5)}$$

$$Net\ MWh_{elec} = MWh\ Generator + MWh\ Auxiliary - MWh\ Consumed \quad \text{(Eq. 6)}$$

$$Net\ MWh_{Cogen} = Net\ Heat \times (1\ MWh)/(3.412\ MMBtu) \quad \text{(Eq. 7)}$$

$$Net\ Heat = Heat\ Generator + Heat\ Auxiliary - Heat\ Consumed \quad \text{(Eq. 8)}$$

Figure 7: Summary of Emissions Calculation



As discussed in Section 3.3, the project emissions include both “direct” and “indirect” emissions. Direct emissions are those that occur at a point within the project boundary and indirect emissions are emissions associated with energy sources received by the project but whose emissions occur outside the ownership or control of the project (such as purchased electricity or steam). Figure 8 below summarizes the types of direct and indirect emissions that appear in Eq. 1-8.

Figure 8: Direct and Indirect Emissions Sources

Direct		Indirect
CO_2e *Generator*	CO_2 *Transfer*	CO_2e *Purchased*
CO_2e *Auxiliary*	CO_2 *Fugitive*	
CO_2e *Equipment*		

5.3 CO_2e Emissions

Electric generation and fuel use for heat or operational purposes may emit CH_4 and N_2O, which are greenhouse gases. These emissions are assumed to be emitted without capture even at facilities with a carbon capture system.

All direct and indirect emissions sources should include the CO_2e emissions from these molecules based on their global warming potential. Direct sources should base CH_4 and N_2O emissions on the consumed fuel content and the facility's operational characteristics, to the extent that these emissions are not captured. Indirect sources, such as purchased heat and electricity, should use emission rates that include these GHGs.

Factors for global warming potential should be based on the latest Assessment Report available from the Intergovernmental Panel on Climate Change.

5.4 Generator and Capture CO_2e Emissions

Emissions from the generating unit and the capture and compression of CO_2 include direct and indirect components: the uncaptured emissions from on-site heat and electric generation, and the emissions from purchased energy. Emissions are measured by comparing:

- the total quantity of emissions produced or attributable to the generator and capture system from fuel or other energy inputs, and
- the volume of CO_2 that is transferred to the next segment, CO_2 transport.

$$CO_2e\ Emissions_{G\&C} = CO_2e\ Generator + CO_2e\ Auxiliary_C + CO_2e\ Purchased_C - CO_2\ Transfer_T \quad \text{(Eq. 2)}$$

CO_2e Emissions$_{G\&C}$	This component includes all CO_2e emissions produced by or attributable to the generating unit(s) and the capture and compression system, less the amount transferred to the transport or storage segments.
CO_2e Generator	This component includes all direct CO_2e output from the electric generating unit(s), not only the portion of CO_2 that is uncaptured or emitted. This can either be measured directly downstream of the generating unit(s) or calculated from the total fuel input.
CO_2e Auxiliary$_C$	If the capture process uses energy from on-site heat and electric generation that is not included in the calculation of *CO_2e Generator*, then it should be included here. This can either be measured directly downstream of the auxiliary equipment or calculated from the total fuel input.
CO_2e Purchased$_C$	Indirect emissions from purchased heat or electric generation used to operate the capture and compression system should be included in this component. Emissions from energy procured from a specific facility can either be measured directly downstream of the energy source or calculated from the total fuel input. Energy that is not procured from a specific facility should follow Scope 2 Guidance to determine the appropriate emission factor attributable to that purchase.
CO_2 Transfer$_T$	CO_2 captured and transferred to the CO_2 pipeline or directly to a storage facility is included in this component. This should be measured at the point of transfer.

Emissions from the capture and compression of CO_2 include direct and indirect components: the uncaptured emissions from on-site heat and electric generation and emissions from purchased energy.

5.5 Transport CO_2e Emissions

Emissions from the transport of CO_2 include direct and indirect components: the uncaptured emissions from stationary equipment operating along the pipeline, vented or fugitive CO_2, and emissions from purchased energy.

$$CO_2e\ Emissions_T = CO_2e\ Transfer_T + CO_2e\ Equipment_T + CO_2e\ Purchased_T - CO_2\ Transfer_S \quad \text{(Eq. 3)}$$

$CO_2e\ Emissions_T$	This component includes all CO_2e emissions produced by or attributable to the transport segment, less the amount transferred to the storage segments.
$CO_2e\ Equipment_T$	Emissions from the operation of stationary equipment used to transport CO_2 from the capture facility to the storage site. This can either be measured directly downstream of the stationary equipment or calculated from the total fuel input.
$CO_2e\ Purchased_T$	Indirect emissions from purchased heat or electric generation used to operate the transport system should be included in this component. Emissions from energy procured from a specific facility can either be measured directly downstream of the energy source or calculated from the total fuel input. Energy that is not procured from a specific facility should follow Scope 2 Guidance to determine the appropriate emission factor attributable to that purchase.
$CO_2\ Transfer_S$	CO_2 delivered to the CO_2 storage site is included in this component. This should be measured at the point of transfer. Any difference between $CO_2\ Transfer_T$ and $CO_2\ Transfer_S$ represents the fugitive emissions from the transport segment.

5.6 Storage CO_2e Emissions

Emissions from the storage of CO_2 include direct and indirect components: the uncaptured emissions from stationary equipment operated for storage, vented or fugitive CO_2, leakages from storage, and emissions from purchased energy.

$$CO_2e\ Emissions_S = CO_2e\ Transfer_S + CO_2e\ Equipment_S + CO_2e\ Purchased_S - CO_2\ Transfer_I + CO_2e\ Fugitive_S \quad \text{(Eq. 4)}$$

$CO_2e\ Emissions_S$	This component includes all CO_2e emissions produced by or attributable to the storage segment.

$CO_2e\ Equipments_S$	Emissions from the operation of stationary equipment used to sequester CO_2 received at the storage site. This can either be measured directly downstream of the stationary equipment or calculated from the total fuel input.
$CO_2e\ Purchaseds_S$	Indirect emissions from purchased heat or electric generation used to operate the storage system should be included in this component. Emissions from energy procured from a specific facility can either be measured directly downstream of the energy source or calculated from the total fuel input. Energy that is not procured from a specific facility should follow Scope 2 Guidance to determine the appropriate emission rate attributable to that purchase.
$CO_2\ Transfer_I$	CO_2 injected into the storage site is included in this component. This should be measured at a flow meter placed as proximate to the injection well as is feasible. Any difference between $CO_2\ Transfers_S$ and $CO_2\ Transfer_I$ represents fugitive emissions from the storage segment upstream of the flow meter used to measure the injection quantity.
$CO_2\ Fugitives_S$	This includes the CO_2 that is emitted by equipment located in between the flow meter used to measure injection quantity and the injection well. This should be measured in accordance with applicable regulations.[19]

5.7 Emissions from Utilization

EACs sourced from carbon utilization projects (including EOR and EGR) should include in $CO_2e\ Equipments_S$ and $CO_2e\ Purchaseds_S$ the emissions associated with injecting CO_2 delivered to storage and any other activities dedicated to its permanent storage. If any portion of the CO_2 is released or expected to be released to the atmosphere between injection and permanent storage, $CO_2\ Transfer_I$ should be adjusted to exclude this quantity. The Registering Entity's Measurement Plan described in Section 7.2 must fully describe the methodology used to calculate these emissions.

[19] See 40 CFR Part 98, Subpart RR and 40 CFR Part 98, Subpart W.

Registries that elect to issue certificates to projects with utilization components should align their practices with applicable regulations and other nationally or internationally recognized carbon accounting methodologies.

5.8 Megawatt-Hours

The calculation of net megawatt-hours is needed to determine how many EACs the Registry will issue and to determine the denominator in the emission rate associated with the EAC, as defined in Section 5.2.

$$Net\ MWh = Net\ MWh_{elec} + Net\ MWh_{Cogen} \quad \text{(Eq. 5)}$$

$Net\ MWh$ should be used as the denominator in the emission rate calculation. All projects will receive a number of EACs equal to the $Net\ MWh_{elec}$ parameter, not the $Net\ MWh$ parameter.[20] The $Net\ MWh_{Cogen}$ parameter, and the treatment of cogeneration projects, is discussed in Section 5.9.

$$Net\ MWh_{elec} = MWh\ Generator + MWh\ Auxiliary - MWh\ Consumed \quad \text{(Eq. 6)}$$

$Net\ MWh_{elec}$	The net electric megawatt-hours generated by a project serves as the basis for the number of EACs to issue and as the denominator, or part of the denominator for combined heat and power facilities, in the EAC's respective emission rates. The Net Megawatt-Hours Electric are those that are produced, net of the electricity consumed at the project site.
$MWh\ Generator$	Include all electric energy produced by the principal electric generating unit(s) less the amount used by the electric generating unit(s) for station service unassociated with the CCS capabilities. This represents the amount of electricity that would be delivered to the wholesale electric grid (or the customer, if not connected to the wholesale grid) in the absence of CCS capabilities.

[20] For non-cogeneration projects these two terms will be equal.

MWh Auxiliary	Include all electric energy produced by auxiliary equipment used on-site to operate the capture and compression, transport, and storage processes. Only include the transport and storage processes if they consume electricity generated on-site.
MWh Consumed	Include all electric energy consumed (sometimes referred to as "parasitic load") on-site to operate the capture and compression, transport, and storage processes. Only include the transport and storage processes if they consume electricity generated on-site.

5.9 Cogeneration

While this standard is only applicable to electric power generation, it is necessary to provide an accounting mechanism for projects where electricity is not the only output. In the case of a cogeneration project that produces electricity and heat, the emissions quantified in Sections 5.4-5.7 should be allocated between the electricity and heat products.

If the EAC's emission rate were to be calculated by dividing all emissions by only the net electric generation, all cogeneration project emissions would effectively be allocated to the electricity product. This section describes how to calculate a MWh-equivalent for net heat output, which is added to the denominator of the emission rate. In effect, this adjustment allocates a portion of project emissions to the heat product.

Note that projects that use all heat on-site to operate the carbon capture system are not considered to have any Net Heat output. For these projects $Net\ MWh_{Cogen} = 0$ and $Net\ MWh = Net\ MWh_{elec}$.

$$Net\ MWh_{Cogen} = Net\ Heat \times (1\ MWh)/(3.412\ MMBtu) \qquad \text{(Eq. 7)}$$

$$Net\ Heat = Heat\ Generator + Heat\ Auxiliary - Heat\ Consumed \qquad \text{(Eq. 8)}$$

$Net\ MWh_{Cogen}$	Heat produced by a cogeneration facility is converted to a term denominated in MWh.

Net Heat	The net thermal energy generated by a project determines the necessary adjustment to a project's emission rate. The net heat does not affect the number of electricity attributes created. *Net Heat* is the thermal energy that is produced or consumed at the project site, measured in million British Thermal Units (MMBtu).
Heat Generator	Include all thermal energy produced by the principal electric generating unit(s).
Heat Auxiliary	Include all thermal energy produced by auxiliary equipment used on-site to operate the capture and compression, transport, and storage processes. Only include the transport and storage processes if they consume electricity generated on-site.
Heat Consumed	Include all thermal energy consumed (sometimes referred to as "parasitic load") on-site to operate the capture and compression, transport, and storage processes. Only include the transport and storage processes if they consume heat generated on-site.

While the scope of this standards document is limited to EACs for electric power, certificates for thermal emissions attributes, denominated in lbs-CO_2e-per-MMBtu, could be compatible with this methodology to support claims associated with low carbon heat.[21]

5.10 Emission Rate

The lbs-CO_2e-per-MWh associated with each CCS EAC is its emission rate. The numerator is the sum of the CO_2e emissions within the project boundary and the denominator is the Net Megawatt-Hours produced by the project. This is expressed as:

$$\frac{CO_2e\ Emissions_{G\&C} + CO_2e\ Emissions_{T} + CO_2e\ Emissions_{S}}{Net\ MWh} \qquad \text{(Eq. 1)}$$

[21] Because a cogeneration project would create $Net\ MWh_{elec}$ EACs bearing an emission rate of $(CO_2e\ Emissions_{G\&C} + CO_2e\ Emissions_{T} + CO_2e\ Emissions_{S})/(Net\ MWh_{elec} + Net\ MWh_{Cogen})$, the remaining emissions attributable to the heat from cogeneration project under this methodology would equal $Net\ MWh_{Cogen} \times (CO_2e\ Emissions_{G\&C} + CO_2e\ Emissions_{T} + CO_2e\ Emissions_{S})/(Net\ MWh_{elec} + Net\ MWh_{Cogen})$.

6 Application of Methodology

6.1 Issuance of EACs

This standard assumes each CCS EAC will represent one megawatt-hour of net generation, similar to existing EACs. Registries may also create certificates at a finer level of granularity (at the kilowatt-hour / “milli-EAC” level or watt-hour / “micro-EAC” level).

Registries are encouraged to issue EACs for all project generation to ensure that all emissions associated with the project are tracked and accounted for. This includes generation when carbon capture equipment is undergoing maintenance or otherwise unavailable, such as when electric generating unit dispatch may be outside of the project operator’s control and needed to meet reliability or regional grid needs. Issuing EACs at an hourly granularity, as discussed in Section 6.2, or with a designation indicating whether the capture equipment is operating would allow attribute holders to differentiate EACs based on the operating characteristics of the CCS equipment. The contractual provisions between the Registering Entity and the counterparty that receives the EACs should specify any difference in value ascribed to EACs issued in hours of varying CCS performance and specify any requirement to ensure that all EACs are retired.

Although CCS EACs represent a new application for Registries, a CCS EAC can be issued, tracked, and retired in the same fashion as an EAC originating from a renewable, nuclear, biomass, or other fuel source. The best practices governing the issuance, tracking, and retirement currently implemented by Registries will be equally applicable to CCS EACs.

6.2 Granularity of EACs

Many large electricity users track electricity consumption and associated emissions at an hourly level to meet their sustainability goals,[22] and energy tracking registries have begun issuing some energy attribute certificates with a time stamp representing the day and hour that the electricity was generated.[23] While the methodology described in this standard recognizes the low-carbon characteristics of CCS-equipped electric generating units, the dispatchable, firm, round-the-clock profile of these resources may not be apparent unless the EAC is issued at an hourly level of granularity.

This standard encourages Registries to issue hourly granular certificates when possible. Each Registry may determine the appropriate level of granularity with which to

[22] https://gocarbonfree247.com/our-signatories/

[23] Gerber, Ben, *A Path to Supporting Data-Driven Renewable Energy Markets*, 2021.

issue its EACs depending on its technical capabilities and internal resources. A Registry may also allow the Registering Entity to select between an hourly, monthly, quarterly, or annual level of granularity based on its preference.

Data for generation and capture emissions and power generation should match the time interval of the EAC, whether hourly, monthly, quarterly or annual. Because of the time needed for CO_2 to traverse the transport and storage system, the hourly profile of transport and storage emissions may not match the hourly profile of generation and capture emissions. To reflect this potential discrepancy, this standard recommends that projects receiving hourly EACs have transport and storage emissions calculated on a monthly, quarterly or annual basis. These emissions should then be allocated pro rata across all EACs in that month, quarter, or year, proportional to the tons of CO_2 added to the system during each EAC's time interval.

To do this, Registries may apply a "system factor" that allocates transport and storage segment emissions based on a calculation of average transport and storage emissions per ton of CO_2 added to the system, similar to an electric line loss factor. This is further described in Sections 6.3 and 6.4. This standard considers the use of a transport and storage system factor to be consistent with the issuance of hourly certificates.[24]

If any generation or capture emissions occur in hours when there is no generation, such as from turnaround activities or loss of containment during maintenance periods, these emissions should be allocated pro rata to all megawatt-hours across an interval no shorter than a month and no longer than a year.

6.3 System Factor - Single-Source System

For a transport and storage system that handles CO_2 from a single source (the CCS-equipped generating facility), a System Factor may be used to aggregate Transport and Storage emissions across a month, quarter, or year, then allocate these emissions pro rata across all CO_2 that enters the transport and storage segments in that quarter or year.

The System Factor for a single-source system is defined by the formula in Eq. 9 below. The Transport and Storage emissions are calculated in accordance with the methodology in Sections 5.5 and 5.6.[25]

[24] A system factor for the transport and storage segments may also have the effect of applying emissions from infrequent venting events across all hours, which allocates the impact of these events to all megawatt-hours.
[25] See Appendix D for an example of the computation of a system factor using Eq. 9.

$$System\ Factor = \frac{\sum_{Hours} (CO_2e\ Emissions_T + CO_2e\ Emissions_S)}{\sum_{Hours} CO_2\ Transfer_T} \qquad \text{(Eq. 9)}$$

The System Factor is applied by multiplying the *System Factor* by the $CO_2\ Transfer_T$ term and replacing $CO_2e\ Emissions_T + CO_2e\ Emissions_S$ in Eq. 1. Projects using the System Factor then use Eq. 1a below in place of Eq. 1. This treatment ensures that the Transport and Storage emissions allocated to each EACs will be proportional to the amount of CO_2 captured.

$$\frac{CO_2e\ Emissions_{G\&C} + CO_2\ Transfer_T \times System\ Factor}{Net\ MWh} \qquad \text{(Eq. 1a)}$$

6.4 System Factor - Multi-Source System

A System Factor may also be used for transport networks and storage sites that manage CO_2 from multiple sources in order to allocate a share of emissions from the system to the Registering Entity. This System Factor will calculate direct CO_2e emissions, indirect CO_2e emissions, and CO_2 losses during transport and storage across the entire system, as well as the total quantity of CO_2 added to the system, in order to determine the tons of emissions attributable to each ton of CO_2 added to the system.

In a multi-source system, the System Factor calculation is similar to the single-source system, however it requires some data relevant to other projects using the system, such as the quantity of CO_2 transferred to the system. The multi-source System Factor is defined in Eq. 10 below.

$$System\ Factor_{Multi} = \frac{\sum_{Sources} \sum_{Hours} (CO_2e\ Emissions_T + CO_2e\ Emissions_S)}{\sum_{Sources} \sum_{Hours} CO_2\ Transfer_T} \qquad \text{(Eq. 10)}$$

Eq. 1b, similar to Eq. 1a shown in the previous section, is again used to replace $CO_2e\ Emissions_T + CO_2e\ Emissions_S$ in Eq. 1 with the product of the $CO_2\ Transfer_T$ term and the $System\ Factor_{Multi}$ defined by Eq. 10. Projects using the multi-source System Factor then use Eq. 1b below in place of Eq. 1.

$$\frac{CO_2e\ Emissions_{G\&C} + CO_2\ Transfer_T \times System\ Factor_{Multi}}{Net\ MWh} \quad \text{(Eq. 1b)}$$

If possible, projects that deliver CO_2 to a multi-source system are encouraged to allocate the direct and indirect emissions associated with operating the transport system in a manner that recognizes that emissions attributable to each source may vary based on the distances traveled from the sources to the point of storage and the emissions intensity of operating each segment of the system. In such a calculation, the share of the project's CO_2 input would be calculated at each point where multiple sources converge. Emissions for each segment, calculated according to the methodology in Section 5.5, would be allocated by each source's share of CO_2 in the pipeline at the beginning of that segment. Total transport emissions would reflect the sum of the project's share of each transport segment. Storage emissions would be allocated to reflect the share of the project's CO_2 input relative to the storage site's total CO_2 input.

If data are not available for transport and storage components at the time an attribute is issued, such as emissions factors applicable to indirect emissions, a project may consider using a rolling emissions factor for those components based on the most recent historical data.[26]

6.5 Treatment of Electricity for Capture and Compression, Transport, and Storage

The calculation methodology in Section 5.8 permits the treatment of electricity used for capture and compression in either of two ways: 1) as parasitic load that reduces the project's total net electric power output or 2) as equipment outside the project boundary, served by a grid supplier and carrying indirect emissions. Under the first option, the electric consumption is included in *MWh Consumed,* which reduces the project's $Net\ MWh_{elec}$. Under the second option, the electric consumption is treated as a source of indirect emissions in the $CO_2e\ Purchased_C$ component, which increases the project's $CO_2e\ Emissions_{G\&C}$. A project may elect either treatment independent of the electrical engineering configuration of the facility.[27]

[26] A Registry may require that the Registering Entity true up any discrepancies between the historical factor and actual emissions for that period.

[27] This example applies to the treatment of Transport or Storage segment electricity consumption as well.

6.6 Electric Generating Units Included

The methodology in this standard assumes that CCS equipment will be configured to process all CO_2 emissions produced by one or more electric generating units. For some projects, especially those that retrofit CCS capabilities onto existing electric generating units, the CCS equipment could be sized to process some, but not all, of the emissions from a plant or unit due to technical constraints.

Registries may permit retrofit projects to include a fraction of an electric generating unit within the project boundary. This fraction should be determined by the Registering Entity and be equal to the proportion of the emissions treated by the capture unit relative to the total emissions when all electric generating units in the project boundary are operating at maximum capacity.[28] For CCS projects at electric generating units that are not in operation nor under construction at the time this standard is published, electric generating units are expected to be wholly included or excluded from the project boundary.

[28] For example, an electric generating unit that is capable of sending 70% of its flue gas to a post-combustion capture unit when operating at maximum capacity should include 70% of the generating unit within the project boundary.

7 Measuring, Verification, and Monitoring

7.1 Project-Specific Plans

Registries should require rigorous documentation of project specifics, measurement, data collection procedures, and verified project data to increase transparency and build market confidence in CCS EACs. A Registering Entity's Measurement Plan allows it to accurately quantify the amount of CO_2 emitted and demonstrate the effectiveness of the CCS system. Sufficient verification procedures are necessary to instill confidence in CCS projects and give attribute holders insight into their energy purchases. Monitoring procedures assure the durability of a project's attributes.

Specific measurement, verification, and monitoring procedures are already necessary for compliance with U.S. federal, state, and local regulations and can be used to meet the requirements of this section. The EPA's Subpart RR, concerning the Geologic Sequestration of Carbon Dioxide, requires facilities to submit a detailed monitoring, reporting, and verification plan that identifies potential leakage pathways, strategies for quantifying leakages, and data on CO_2 injection volumes. A project seeking to claim emissions reduction credits under California's Low Carbon Fuel Standard must report GHG emissions reduction measurements, containment monitoring results, and a summary of any leakage incidents to a verification team. North Dakota, the first state to receive primacy to implement its own Class VI Underground Injection Control program, requires facilities to file quarterly reports on the volume of CO_2 injections and site operations with the North Dakota Industrial Commission. Entities managing the safety, operations, and crediting of CCS facilities recognize the importance of setting high standards for documentation and data collection.

Rigorous documentation provides the means to accurately measure, verify, and monitor a project's operations and emissions. This standard proposes three core forms of documentation:

- A detailed Measurement Plan
- Third-Party verification of project data
- A Monitoring and Reporting Plan for containment

Additionally, the Registry may require or recommend that all personnel involved in the design, operation, and monitoring of CO_2 injection and storage wells undergo specialized

Well Control and Integrity Management training, proposed in Appendix E: Well Control and Integrity Management Training.

7.2 Measurement Plan

The engineering configuration of each CCS project will be unique. While Section 5 provides high-level description of the categories of emissions to include, the Registering Entity must demonstrate to the Registry how it is adhering to the calculation methodology. To support this demonstration, the Registering Entity should submit a Measurement Plan that describes the data to be collected. This plan should include, at a minimum:

- Engineering documentation of the project, annotated with a list of all meter points and the entity that owns and operates the equipment at each meter point.
- A description of the data to be collected at each meter point, including the relevant measurement units.
- The frequency at which data will be collected (expected to be hourly or subhourly).
- A prescribed frequency of maintenance and calibration of meter points.
- A description of how transport and storage emissions will be calculated, including all components of the calculation and points of measurement.

Other elements recommended for inclusion:

- Documentation of any instances where estimated rather than measured data is relied upon with a description of, and justification for, how estimates are derived.
- A description of how the emissions associated with EOR or other forms of utilization are calculated, if applicable.

The Measurement Plan should also outline procedures to manage data quality issues and missing data. While the Registering Entity should first and foremost strive to prevent and minimize risks to data quality and integrity, it should also prepare for contingencies where not all data are available to perform the necessary calculations for a Registry to issue an EAC. Regulations concerning CO_2 Sequestration, such as 40 CFR Part 98, Subpart RR in the U.S., include procedures for estimating missing data.

Any estimates for missing data should be in line with industry best practices, Greenhouse Gas Protocol guidance, and applicable regulations. Where estimates are used in lieu of measured data, the Registering Entity should be transparent and conservative in its estimate. A Registry may refuse to issue EACs backed by estimates of missing data or set a materiality threshold for the amount of estimated data that it is willing to accept in lieu of verified, measured data. Registries may consider less lenient acceptance of data estimates as carbon capture technologies and projects mature, reflecting an increasing standard for accuracy, completeness, and transparency.

7.3 Verification

To ensure confidence in the accuracy of the emission rate minted on the EAC, all projects should have an independent third-party verify all data described in the Measurement Plan. This is especially important given that data will likely originate from multiple entities across the project boundary. No EACs should be issued until all underlying data is verified.

This third-party verification should be completed at least once per year and a verification report should be submitted to the Registry to demonstrate its completion. The Registering Entity and third-party verifier should attest that the data the Registering Entity submits is true, complete, and correct to the best of its knowledge, information, and belief. The verification report should also verify that the project configuration described in the Measurement Plan remains accurate. To the extent possible, the Registering Entity should submit data that is reported to regulatory agencies (such as the U.S. EPA) or is received from independent bodies (such as settlement data from Independent System Operators) for ease of verification.

The Registry may request the credentials of the third-party verifier and may reject the third-party verifier if it deems it has insufficient technical expertise in CCS applications. This could include requiring that the verifier is a registered engineering firm with at least three years of experience in CCS or well integrity and has a professional engineer registered in the state in which the storage is located.

7.4 Monitoring

To ensure confidence in the permanence of the carbon stored or utilized by the CCS project, the Registering Entity should require each project to submit and update a Monitoring and Reporting Plan.

All projects must submit a Monitoring and Reporting Plan with requirements at least as stringent as the 40 C.F.R. Part 98, Subpart RR requirements.[29] EPA-approved Monitoring, Reporting, and Verification plans will satisfy this requirement, as will Measurement,

[29] Although subpart RR requirements apply to facilities with wells that inject CO_2 for long-term geologic sequestration and do not apply to EOR projects, many EOR projects nonetheless have EPA-approved Monitoring, Reporting, and Verification plans. If a Registry includes EOR end uses, imposing these requirements on EOR projects will not be unduly burdensome.

Monitoring, and Verification plans approved by the California Air Resources Board and plans in compliance with ISO 27916. The relevant requirements of greatest importance to the EAC include disclosing:

- Delineation of the maximum and active monitoring areas
- Identification of potential CO_2 leakage pathways in the maximum monitoring area and the likelihood, magnitude, and timing of surface leakage through these pathways
- A strategy for detecting and quantifying any surface leakage of CO_2
- A strategy for establishing the expected baselines for monitoring CO_2 surface leakage
- A summary of the considerations intended for use to calculate site-specific variables for the mass balance equation. This includes, but is not limited to, considerations for calculating CO_2 emissions from equipment leaks and vented emissions of CO_2 between the injection flow meter and injection well and/or the production flow meter and production well, and considerations for calculating CO_2 in produced fluids
- UIC well number(s), if permitted under the UIC program
- Proposed date to begin collecting data for calculating the total amount of CO_2 sequestered

The Monitoring and Reporting Plan should be maintained throughout the project and, similar to Subpart RR requirements, annually report:

- The mass of CO_2 received;
- The mass of CO_2 injected into the subsurface;
- The mass of CO_2 produced (mixed with produced oil, gas, or other fluids);
- The mass of CO_2 emitted by surface leakage;
- The mass of CO_2 emitted as equipment leakage or vented from surface equipment;
- The mass of CO_2 sequestered in subsurface geologic formations; and
- The cumulative mass of CO_2 sequestered since the start of required reporting.

In their Monitoring and Reporting Plans, Registering Entities are encouraged to provide additional detail on the most likely pathways of surface leakage, such as nearby legacy well infrastructure, and methods to mitigate leakage risk at these pathways, such as the monitoring and inspection strategy of all casings.

Section 8 discusses additional assurances against post-injection leakage. Current U.S. regulations require long-term post-injection monitoring at Class VI wells in accordance with an approved site care and site closure plan.[30] CCS projects should follow applicable regulations for post-injection monitoring and reporting.

[30] 40 CFR Part 146, Subpart H

8 Leakage

8.1 Overview

The integrity of a CCS EAC depends on ensuring permanence of the stored CO_2. Assurances of the permanence in storage of captured CO_2 is necessary to garner acceptance of CCS EACs by Registries and attribute holders alike. Without provisions to account for the potential of leakage of stored emissions, the utility of these certificates could be harmed.

CCS projects have strong incentives for protecting against leakage. In addition to a storage site operator's liability for the sequestered CO_2, operators must abide by federal and local regulations that are designed to prevent or quantify leakage of any CO_2 from storage formations.[31] The Section 45Q Tax Credit for Carbon Sequestration provides a strong financial incentive to prevent leakage; carbon leakage reduces the amount of qualified carbon dioxide a taxpayer can claim credit for in a year or requires a taxpayer to refund credits from previous years.[32] Because this tax credit can be worth up to $85 per ton of CO_2 for electric facilities with CCS before adjusting for inflation, the recapture of this credit provides a strong deterrent to leakage.

Current permitting procedures, regulations, and the Tax Credit for Carbon Sequestration are intended to manage the prevention and remediation of leakage events. Several states have imposed additional requirements on CCS projects; Registries may choose to apply these or other requirements to all projects receiving EACs.

Unlike federal tax credits, a CCS EAC may not be modifiable after the certificate is retired, and after-the-fact leakage may affect the associated emissions claimed for a retired credit. This standard seeks to demonstrate how the potential effects of leakage events can be addressed to assure that claims made on previously minted EACs remain credible.

8.2 Addressing Potential Leakage

In the event of post-injection leakage, the Registering Entity must commission an engineering study to estimate the quantity of CO_2 that has been released to the atmosphere. If the leakage occurs from a storage site that receives injections from multiple projects, the

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[31] For example, see EPA, Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells Final Rule or Illinois Compiled Statute 415 ILCS 185/ Safety and Aid for the Environment in Carbon Capture and Sequestration Act.

[32] Internal Revenue Service, CFR 2023 Title 26, Vol. 1 Sec1-45Q-5.

Registering Entity should receive an allocation of the estimated CO_2 released based on its pro rata share of CO_2 injected into the storage structure.

As a proactive insurance measure, Registries should require the Registering Entity to adopt one of the following approaches to mitigate concerns of potential post-injection leakage:

- **Insurance policy from market**: The Registering Entity will acquire and maintain an insurance policy from a commercial insurer that protects against the possibility of leakage. In the event of CO_2 leakage, the insurance company will have the obligation to remediate the leakage, such as by purchasing and retiring EACs that can be credited against the measured quantity of leakage.

- **EAC Reserve, site-specific**: The Registering Entity will hold back a share of the EACs issued from the project in a reserve. These EACs will remain unretired as collateral against leakage.[33] Rather than issue and track unretired EACs, the Registry may alternatively implement this option by declining to issue EACs that would be placed in an EAC Reserve.

  The share of EACs held back by the Registering Entity should be based on a site-specific engineering study using the best available information concerning the likelihood and magnitude of leakages from the injection site and tied to the CO_2 released under a 95th percentile outcome at the site. Assuming that the volume of estimated leakage under a 95th percentile outcome increases as the total amount of CO_2 injected at the storage site increases, the Registry will continue to add EACs into the reserve in accordance with the estimated outcomes in the site-specific engineering study.[34]

- **EAC Reserve, generic**: Similar to the site-specific reserve above, a Registry may specify a generic percentage of EACs to place in reserve. Without the precision of a site-specific engineering study, the quantity of EACs required to be placed in the reserve should be set sufficiently high to account for uncertainty about leakage potential. As a result, this holdback should be based on a 99th percentile outcome based on the best available

[33] Underlying this concept is the principle that if X% of the total carbon injected from the project is estimated to have escaped, this leakage can be remediated by retiring X% of the total EACs issued to the project. In the event of leakage, a quantity of EACs from the reserve will be retired such that the ratio of EACs retired relative to total EACs issued is equal to the ratio of estimated CO_2 released relative to the total CO_2 injected.

[34] The Registering Entity should ensure that the average emission rate of the EACs held in reserve is equal to or lower than the average emission rate of all EACs issued from the project. The Registering Entity may remove EACs of older vintage from the reserve and replace them with EACs of newer vintage provided that the previous condition is met.

information concerning the likelihood and magnitude of leakages at similar CO_2 injection sites including engineering studies, academic research, and industry experience.

Current research indicates that no more than 1.0% of carbon stored is expected to be released as atmospheric leakage from saline aquifer injection sites in 99% of cases.[35] Therefore, a generic EAC Reserve provision would require that 1.0% of all issued EACs be placed in the reserve for geological storage in saline aquifers. For other types of storage sites, or for utilization pathways, additional research would need to be identified or completed to establish a generic EAC Reserve requirement.

- **Carbon Credit Reserve (site-specific or generic)**: Similar to the EAC Reserve, the Registering Entity would establish a reserve to be used to remediate leakage, if it occurs, however tons-based carbon credits would be acquired and held in the reserve. Like the EAC Reserve, this reserve would be sized to a site-specific or a generic estimate of the tons of CO_2 that could leak under a 95th or 99th percentile outcome, respectively, based on the best available information concerning the likelihood and magnitude of leakages from the injection site. The Registry should place restrictions on the qualifying carbon credits based on location and project type. Qualifying credits should be restricted to the same country or region of origin as the CCS project and may be restricted in alignment with the standards imposed by other state programs or greenhouse gas regimes.[36] Registries may consider requiring carbon credits in a reserve to be sourced from CCS projects that do not pursue EACs or from direct air capture projects.
- **Adjustment to EAC emission rate (site-specific or generic)**: A Registry, a Registering Entity, or an EAC holder may prefer to add an estimate of potential post-injection leakage into any claims backed by a CCS EAC. In that event, the Registry could allow the Registering Entity to elect to add additional tons into the calculation shown in Section 5.10. A new term, a CO_2 Leakage Buffer, would be added in the numerator such that $CO_2\ Leakage\ Buffer = (CO_2\ Transfer_I) \times (Est.\ \%\ Leakage)$. As in the EAC Reserve option above, the *Est. % Leakage* parameter would be sized to a site-specific or a generic estimate of the percentage of injected CO_2 that could be released under a 95th or 99th percentile

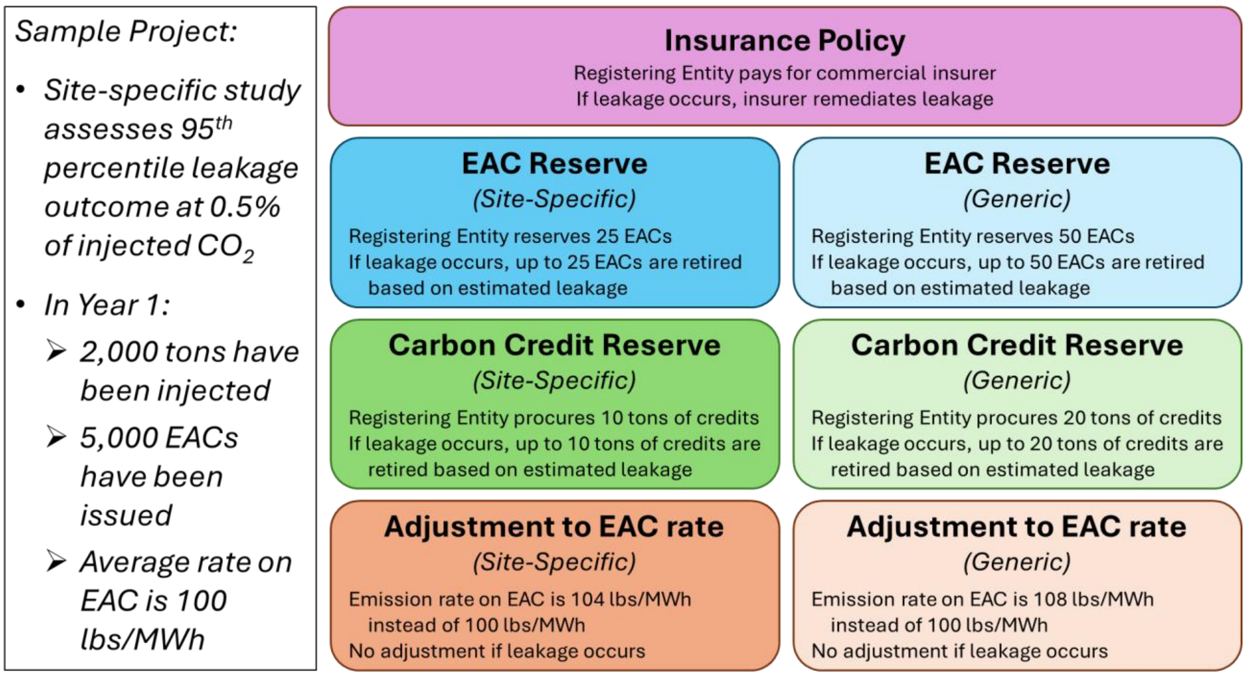
[35] Hillix, D. Michael, et al. *Quantifying the Potential Atmospheric Leakage Risks Associated With the Geologic Storage of CO2 in Saline Aquifers for Use in Voluntary Carbon Market Buffer Account Determination*, Proceedings of the 17th Greenhouse Gas Control Technologies Conference (GHGT-17), 2024

[36] For example, the Regional Greenhouse Gas Initiative (RGGI) of eleven states permits five types of offsets: Landfill methane capture, sulfur hexafluoride, forestry or afforestation, end-use efficiency, and avoided agricultural methane. Several RGGI states permit only projects related to landfill methane capture, forestry (excluding afforestation), and avoided agricultural methane projects.

outcome, respectively, based on the best available information concerning the likelihood and magnitude of leakages from the injection site.

An example of how these provisions would apply to an illustrative project is shown in Figure 9 below.

Figure 9: Example Potential Leakage Insurance Mechanisms, Illustrative Project



Registries should offer multiple options for compliance and, at a minimum, these options should include the private insurance policy and site-specific EAC Reserve options. This will encourage projects to use a private insurance policy or a site-specific leakage study in some form, which will demonstrate a detailed examination of possible leakage pathways and promote market confidence. The Registry may decide whether to include any or all of the remaining options described above. In time, based on market feedback, a consensus may form around the most credible mechanisms that includes some of the options above or new options.

The Registering Entity should be permitted to switch between the insurance, EAC reserve, or carbon credit reserve options, if offered by the Registry, throughout the lifetime of the project. A Registering Entity should also be permitted to adjust their obligations based on new or updated site-specific assessments as additional site and project data becomes known.

All proposals in this section rely on a self-insurance mechanism that is assessed at the project level and requires individual projects to address post-injection leakage associated with their project. This is designed to encourage best practices for design and operation of storage facilities and to ensure each project retains a strong incentive to mitigate leakage risks. Mechanisms that share risk across multiple projects, such as buffer pools commonly used in carbon credit markets, are not proposed in this standard, but could be considered in the future when a sufficient number of CCS projects achieve operation. This could lead to smaller EAC or carbon credit reserve requirements per project. Any risk sharing mechanism would need to address the variations in the attributes issued to individual projects and site-specific leakage risk factors.

Post-injection leakage should be monitored and reported to Registries and verifiers in accordance with applicable regulations and best practices. Under current U.S. regulations, the recapture period for section 45Q credits due to post-injection leakage ends after the earlier of three years or when the monitoring period ends if the project pursues an alternative post-injection site care timeframe.[37] Registries may define a post-injection reporting timeframe in accordance with industry and regulatory standards.

When the responsibility for a project's stored CO_2 is transferred to a government or state authority, any attributes that had been placed in a reserve may be released to the Registering Entity.

[37] Internal Revenue Service, CFR 2023 Title 26, Vol. 1 Sec1-45Q-5.

9 Other Considerations

9.1 Additionality

Some clean energy buyers prefer or require that their purchases be considered "additional" – that the project would not have been pursued if not for the attribute holder's actions. Though there are varying definitions, this could mean an EAC is from a new or recently constructed facility or one that exceeds existing regulatory requirements.

Historically, the issuance of RECs, Alternative Energy Credits, and other energy attributes certificates has not required an additionality test. This standard does not require imposing additionality requirements on projects that apply for EACs. If concerns about the additionality of CCS projects emerge, a model whereby a separate entity certifies CCS EACs is appropriate, similar to additionality-related criteria applied through the Center for Resource Solutions' Green-e certification for RECs.[38] A Registry may consider gathering any project data that may be relevant for a potential additionality assessment, such as the in-service date of the generator or CCS capabilities, the project's location, or its fuel type.

9.2 Application to Time-Match Statistics or CFE Scores

EACs created under the guidance of this document are primarily designed to facilitate emissions claims made by the bearer under the Greenhouse Gas Protocol. Some clean energy buyers measure progress towards their climate goals based on both the Greenhouse Gas Protocol and other measures such as hourly time-match or "Carbon Free Energy Score" (CFE Score) statistics.

This standard suggests electricity buyers may treat all electricity consumption matched with a CCS EAC as fractionally "clean" for their application to hourly CFE Score or time-matching summaries (rather than requiring each megawatt-hour to fit into a binary scheme of clean and 100% eligible or not clean and 0% eligible). This fractional share may be based on a calculation of the EAC's emission rate relative to the expected emission rate without CCS and is best applied to hourly EACs. Formulaically, this share is expressed as:

$$\left(1 - \left(CO_2e\ Emissions_{G\&C} + CO_2e\ Emissions_{T} + CO_2e\ Emissions_{S}\right) / CO_2e\ Generator\right) \times 100\% \qquad \text{(Eq. 11)}$$

[38] Further, if necessary to consider additionality, Registries may assume that all projects are likely to be additional. The nascency of CCS applications at power plants demonstrates that implementing CCS is not yet common practice. The development of all projects may be assumed to be contingent on the economic support provided by the project sponsor for the foreseeable future.

9.3 Low Carbon Intensity Fuels

Low-carbon fuel standards recognize that some fuels have lower life-cycle emission impacts, especially natural gas that is extracted in a manner that avoids upstream methane emissions (renewable natural gas) or has reduced upstream emissions (certified natural gas). These impacts can be estimated or verified through a carbon intensity metric and compared to natural gas extracted under traditional methods.[39]

This standard does not propose including the impact of using low-carbon-intensity fuels in the CCS EAC, though its potential application is noted. To do so could entangle attributional accounting with impact-based accounting (which assesses emission changes relative to a baseline). At a minimum, incorporating low-carbon-intensity fuels into this standard would require assurances that there is no double counting of the low-carbon intensity attributes (such as in Low Carbon Fuel Standards) and further discussion about whether locational or temporal deliverability requirements are needed. Nonetheless, certificates for low carbon intensity fuels and CCS EACs can both be used complementarily by users to assess a full supply chain emissions accounting footprint.

Low carbon intensity fuels delivered to the Registering Entity's electric generating units, such as certified gas or biomass fuels, are eligible for other crediting programs as long as there is no double counting of the CCS activity credited under this methodology and may be accounted for outside of the attribute holder's Scope 2 emissions.

9.4 Capture Percentage

While this standard is focused on an EAC bearing a lbs-per-MWh emission rate, that need not preclude an EAC from also bearing a capture percentage as an informational metric. As noted in Section 3.1, some attribute holders may have interest in an attribute that conveys a measurement of the percent of carbon captured by the project. This designation may be especially useful for compliance with certain clean energy standards that include CCS if a certain capture rate is achieved, such as Michigan's. Some project developers may wish to demonstrate the efficiency of their unique capture processes in a simple fashion for marketing purposes.

A capture metric is not required by this standard, but a Registry may consider adding a capture percentage to its EACs or calculating one upon request using the verified data used to calculate the EACs' emission rate. Calculating a capture percentage would require

[39] For example, under the MiQ certification standard, methane intensity of natural gas is verified by third-parties and can be compared to national or basin averages for traditional natural gas production.

the Registry to clearly define how the metric treats the boundary for capture claims (whether inclusive or exclusive of the transport and storage segments) and the time interval over which the average capture percentage is calculated.

9.5 Interplay with Carbon Credit Markets

As discussed in Section 2, the carbon credits ecosystem has established CCS methodologies in place today. Energy tracking registries or Registering Entities wishing to leverage the work already done by carbon credit providers could consider partnering with an offset registry when issuing EACs. An existing calculation methodology in use by an offset registry may contain areas of overlap with this standard. It also may provide additional detail on how to include emissions associated with certain components of the CCS project, such as those related to EOR, into a Measurement Plan.

Two avenues for partnership between an energy tracking registry and an offset registry with expertise in CCS are summarized in Figure 10 below: 1) the offset registry serving as an independent, third-party verifier and 2) the energy tracking registry synthesizing an EAC that will replace a carbon credit instrument.

Figure 10: Options for Energy Tracking Registry and Offset Registry Coordination

Offset Registry Serves as Independent Verifier	Energy Tracking Registry Synthesizes EAC Replacing a Carbon Credit
• The Registering Entity registers its project with the **Energy Tracking Registry** • The **Energy Tracking Registry's** calculation methodology is followed • The **Offset Registry** assists in developing the Measurement Plan using its established methodology • The **Offset Registry** acts as third-party verifier to project data • The **Energy Tracking Registry** issues an EAC bearing a lbs/MWh rate	• The Registering Entity registers its project with the **Offset Registry** • The **Offset Registry's** calculation methodology is followed • The **Offset Registry** issues a carbon credit, denominated in tons • The **Registering Entity** delivers the carbon credit, including all verified underlying data, to the **Energy Tracking Registry** • The **Registering Entity** completes a Measurement Plan prescribing how verified data used to create the carbon credit can be utilized to comply with the **Energy Tracking Registry's** methodology • The carbon credit is retired in the **Offset Registry,** then **Energy Tracking Registry** issues an EAC bearing a lbs/MWh rate

10 Future Considerations

10.1 Pathway to Net Zero Emissions

This standard has focused on creating an EAC to facilitate low carbon emissions claims associated with electricity generated by CCS-equipped electric generating units. Some buyers may seek a zero-carbon, rather than low-carbon, attribute. Unless the emission rate minted on a CCS EAC envisioned in this standard is equal to zero, a clean energy buyer may not be able to achieve zero Scope 2 emissions under current Scope 2 rules with a CCS EAC. Options for future consideration are listed in Figure 11 below, however each requires further exploration and none is recommended at this time.

Figure 11: Considerations for Achieving Net Zero EACs

Ways to Reduce Project Emissions	Changes Requiring GHG Accounting or Target Setting Revisions
• Incorporating upstream impacts of low carbon intensity fuels, especially biomass • Including Direct Air Capture (DAC) systems within the project boundary • Allowing retired carbon credits to reduce the EAC emission rate	• Allowing a fraction of a retired REC to eliminate the emissions associated with a low-carbon EAC • Allowing an attribute holder to make a zero-emissions Scope 2 claim if it retires a number of CCS EACs that exceeds its electricity consumption by a sufficient amount

10.2 Evolving CCS Landscape

The standard described in this document is meant to articulate a reasonable, workable system for Registries to follow and is tailored to the CCS and carbon emissions landscape at the time of its writing. In time, especially as the GHG Protocol Standard Update process is completed, some sections of this standard may be superseded by new guidance or may not apply. Registries are welcome to add provisions to their own EAC issuance practices based on their experience and as the landscape changes.

While the authors may create revisions or updates to this standard, they do not currently plan to revise the standard at a regular cadence. Other parties may propose subsequent revisions to this document, with suitable attribution, and are invited to consult with the authors if they do. Registries are encouraged to disseminate their perspectives on best practices, recommended revisions, or implementation challenges.

Appendix A: List of Terms and Definitions

Attribute Holder (or EAC holder): The entity that has title to an energy attribute certificate and who may retire the attribute to claim emissions associated with electricity consumption

Carbon Capture and Storage or Sequestration (CCS): A collection of technologies that isolate carbon dioxide, often from fossil fuel combustion, and prevent its release into the atmosphere

Carbon Dioxide Equivalent (CO_2e): A measure of the global warming potential of several greenhouse gases – carbon dioxide (CO_2), nitrous oxide (N_2O), and methane (CH_4) – weighted by the respective impacts of each gas and normalized to the impact of carbon dioxide emissions

Carbon Free Energy Score (CFE Score): A measure of the degree to which each megawatt-hour of electricity consumption is matched with carbon-free energy generated in the hour of consumption

CCS EAC: An Energy Attribute Certificate that conveys the environmental attributes of the electric output of electric generating units that employ carbon capture and storage technology

CCS-equipped Generating Unit (or, CCS-equipped Facility or Project): An electric generating unit or facility with an integrated carbon capture and sequestration system

Class VI Wells: Sites for geologic sequestration of carbon dioxide as classified and defined by the United States Environmental Protection Agency's Underground Injection Control program

Direct Emissions: Emissions that are measured at points within the project boundary

Electric Generating Unit: The component of a power plant that produces electricity

Energy Attribute Certificate (EAC): A transferable instrument that conveys information about the nature or characteristics of the source of a unit of energy

Energy Tracking Registry (or, Registry): An organization that issues, tracks, and retires Energy Attribute Certificates

Environmental Attribute: A transferable instrument that conveys information relevant to the emissions, fuel source, or other environmental characteristics of the source of a unit of energy

Greenhouse Gas Corporate Accounting Protocol (or, GHG Protocol): A standardized system developed by World Resources Institute and World Business Council for Sustainable Development that is used by energy consumers to measure, quantify, and report levels of greenhouse gas emissions

Indirect Emissions: Emissions associated with energy sources received by the project but whose emissions occur outside the project boundary (such as purchased electricity or steam)

Offset Registry: An organization that issues, tracks, and retires carbon offset credits

Project Boundary: The boundary applied to the measurement and quantification of net electric generation and greenhouse gas emissions attributable to a project

Registering Entity: The organization that serves as the conduit for a carbon capture and storage project in all interactions with the energy tracking registry, submits project data and required reporting, and makes any other required demonstrations or attestations; even if it is not the owner or operator of all segments of the CCS project, the registering entity represents the project as a whole

Renewable Energy Credit (REC): An Energy Attribute Certificate created to convey the attributes from an electricity generating unit powered by renewable energy

Scope 2 Emissions: A component of the Greenhouse Gas Protocol that describes the manner in which corporations account for emissions from purchased or acquired electricity, steam, heat, and cooling

Appendix B: Summary of Equations

$$\frac{CO_2e\ Emissions_{G\&C} + CO_2e\ Emissions_T + CO_2e\ Emissions_S}{Net\ MWh} \quad \text{(Eq. 1)}$$

$$\frac{CO_2e\ Emissions_{G\&C} + CO_2\ Transfer_T \times System\ Factor}{Net\ MWh} \quad \text{(Eq. 1a)}$$

$$\frac{CO_2e\ Emissions_{G\&C} + CO_2\ Transfer_T \times System\ Factor_{Multi}}{Net\ MWh} \quad \text{(Eq. 1b)}$$

$$CO_2e\ Emissions_{G\&C} = CO_2e\ Generator + CO_2e\ Auxiliary_C + CO_2e\ Purchased_C - CO_2\ Transfer_T \quad \text{(Eq. 2)}$$

$$CO_2e\ Emissions_T = CO_2e\ Transfer_T + CO_2e\ Equipment_T + CO_2e\ Purchased_T - CO_2\ Transfer_S \quad \text{(Eq. 3)}$$

$$CO_2e\ Emissions_S = CO_2e\ Transfer_S + CO_2e\ Equipment_S + CO_2e\ Purchased_S - CO_2\ Transfer_I + CO_2e\ Fugitive_S \quad \text{(Eq. 4)}$$

$$Net\ MWh = Net\ MWh_{elec} + Net\ MWh_{Cogen} \quad \text{(Eq. 5)}$$

$$Net\ MWh_{elec} = MWh\ Generator + MWh\ Auxiliary - MWh\ Consumed \quad \text{(Eq. 6)}$$

$$Net\ MWh_{Cogen} = Net\ Heat \times (1\ MWh)/(3.412\ MMBtu) \quad \text{(Eq. 7)}$$

$$Net\ Heat = Heat\ Generator + Heat\ Auxiliary - Heat\ Consumed \quad \text{(Eq. 8)}$$

$$System\ Factor = \frac{\sum_{Hours} (CO_2e\ Emissions_T + CO_2e\ Emissions_S)}{\sum_{Hours} CO_2\ Transfer_T} \quad \text{(Eq. 9)}$$

$$System\ Factor_{Multi} = \frac{\sum_{Sources} \sum_{Hours} (CO_2e\ Emissions_T + CO_2e\ Emissions_S)}{\sum_{Sources} \sum_{Hours} CO_2\ Transfer_T} \quad \text{(Eq. 10)}$$

$$(1 - (CO_2e\ Emissions_{G\&C} + CO_2e\ Emissions_T + CO_2e\ Emissions_S) / CO_2e\ Generator) \times 100\% \quad \text{(Eq. 11)}$$

Appendix C: Application of Methodology to Illustrative Projects

Note: all references to tons in these examples represent metric tons

Illustrative Example #1

Generation and Capture Emissions

$\mathit{CO_2e\ Emissions_{G\&C} = CO_2e\ Generator + CO_2e\ Auxiliary_C + CO_2e\ Purchased_C - CO_2\ Transfer_T}$

- Based on fuel input at electric generating unit, $\mathit{CO_2e\ Generator}$ = 400 tons
- The system requires auxiliary steam to complete the capture process, based on fuel input at the auxiliary boiler, $\mathit{CO_2e\ Auxiliary_C}$ = 30 tons
- There is no purchased energy, as the electricity needed for the capture process is treated as though it is supplied by the generating unit, so $\mathit{CO_2e\ Purchased_C}$ = 0 tons
- The CO_2 transferred to the transport system is measured such that $\mathit{CO_2\ Transfer_T}$ = 410 tons

$\boldsymbol{\mathit{CO_2e\ Emissions_{G\&C}}}$ = 400 + 30 + 0 – 410 = 20 tons

Transport Emissions

$\mathit{CO_2e\ Emissions_T = CO_2e\ Transfer_T + CO_2e\ Equipment_T + CO_2e\ Purchased_T - CO_2\ Transfer_S}$

- Noted before, $\mathit{CO_2e\ Transfer_T}$ = 410 tons
- The project's allocated share of emissions from direct emissions of transport system equipment is $\mathit{CO_2e\ Equipment_T}$ = 2 tons
- The project's allocated share of transport system purchased electricity is 2 megawatt-hours, which are attributed a supplier-specific emission rate of 0.5 tons/MWh. $\mathit{CO_2e\ Purchased_T}$ = 1 ton
- The CO_2 transferred to the storage system is measured such that $\mathit{CO_2\ Transfer_S}$ = 408 tons

$\boldsymbol{\mathit{CO_2e\ Emissions_T}}$ = 410 + 2 + 1 - 408 = 5 tons

Storage Emissions

$\mathit{CO_2e\ Emissions_S = CO_2e\ Transfer_S + CO_2e\ Equipment_S + CO_2e\ Purchased_S - CO_2\ Transfer_I + CO_2e\ Fugitive_S}$

- Noted before, $\mathit{CO_2e\ Transfer_S}$ = 408 tons
- The project's allocated share of emissions from direct emissions of storage system equipment is $\mathit{CO_2e\ Equipment_S}$ = 1 ton
- The project's allocated share of transport system purchased electricity is 4 megawatt-hours, which are attributed a supplier-specific emission rate of 0.5 tons/MWh. $\mathit{CO_2e\ Purchased_S}$ = 2 tons
- CO_2 injected into the storage site is measured such that $\mathit{CO_2\ Transfer_I}$ = 407 tons
- CO_2 that is emitted by equipment located in between the flow meter used to measure injection quantity and the injection well is measured such that $\mathit{CO_2\ Fugitive_S}$ = 1 ton.

$\boldsymbol{\mathit{CO_2e\ Emissions_S}}$ = 408 + 1 + 2 – 407 + 1 = 5 tons

Megawatt-Hours

$\mathit{Net\ MWh = Net\ MWh_{elec} + Net\ MWh_{Cogen}}$

$\mathit{Net\ MWh_{elec} = MWh\ Generator + MWh\ Auxiliary - MWh\ Consumed}$

- 1,000 megawatt-hours are produced by the electric generating unit, so *MWh Generator* = 1,000 MWh
- There is no electric energy produced by auxiliary equipment, so *MWh Auxiliary* = 0 MWh
- The electricity consumed by the capture process is measured such that MWh Consumed = 50 MWh. (Electricity consumed by the transport and storage processes is treated as indirect emissions and not included in MWh Consumed)
- This is not a cogeneration project, no heat is sold, and $\mathit{Net\ MWh_{Cogen}}$ = 0

$\boldsymbol{\mathit{Net\ MWh = Net\ MWh_{elec}}}$ = 1,000 + 0 – 50 = 950 MWh

Emission Rate and EACs Issued

$\mathit{Emission\ rate = (CO_2e\ Emissions_{G\&C} + CO_2e\ Emissions_T + CO_2e\ Emissions_S)\ /\ Net\ MWh}$

- **(20 + 5 + 5) tons / 950 MWh = 0.03158 tons/MWh or 69.6 lbs/MWh**
- **950 EACs issued**

Illustrative Example #2

This example is similar to Illustrative Example #1, with the following changes:

- Electricity provided to the capture process is considered to be sourced by grid power and treated as indirect emissions
- Electricity consumed in the transport segment is sourced by a renewable tariff and attributed zero emissions
- All electricity consumed by the storage segment is sourced from a separate electric generating unit within the project boundary and treated as direct emissions in $CO_2e\ Equipment_S$

Calculation components that differ from Illustrative Example #1 are underlined.

Generation and Capture Emissions

$CO_2e\ Emissions_{G\&C} = CO_2e\ Generator + CO_2e\ Auxiliary_C + CO_2e\ Purchased_C - CO_2\ Transfer_T$

- Based on fuel input at electric generating unit, $CO_2e\ Generator$ = 400 tons
- The system requires auxiliary steam to complete the capture process, based on fuel input at the auxiliary boiler, $CO_2e\ Auxiliary_C$ = 30 tons
- The capture process uses 50 megawatt-hours of purchased energy, which are attributed a supplier-specific emission rate of 0.5 tons/MWh. $CO_2e\ Purchased_C$ = 25 tons
- The CO_2 transferred to the transport system is measured such that $CO_2\ Transfer_T$ = 410 tons

$CO_2e\ Emissions_{G\&C}$ = 400 + 30 + 25 – 410 = 45 tons

Transport Emissions

$CO_2e\ Emissions_T = CO_2e\ Transfer_T + CO_2e\ Equipment_T + CO_2e\ Purchased_T - CO_2\ Transfer_S$

- Noted before, $CO_2e\ Transfer_T$ = 410 tons
- The project's allocated share of emissions from direct emissions of transport system equipment is $CO_2e\ Equipment_T$ = 2 tons
- The project's allocated share of transport system purchased electricity is 2 megawatt-hours, which are attributed a supplier-specific emission rate of 0 lbs/MWh. $CO_2e\ Purchased_T$ = 0 tons
- The CO_2 transferred to the storage system is measured such that $CO_2\ Transfer_S$ = 408 tons

$CO_2e\ Emissions_T$ = 410 + 2 + 0 - 408 = 4 tons

Storage Emissions

$CO_2e\ Emissions_S = CO_2e\ Transfer_S + CO_2e\ Equipment_S + CO_2e\ Purchased_S - CO_2\ Transfer_I + CO_2e\ Fugitive_S$

- Noted before, $CO_2e\ Transfer_S$ = 408 tons
- The project's allocated share of emissions from direct emissions of storage system equipment, including emissions from 4 megawatt-hour of generation at the electric generating unit at the storage site is $CO_2e\ Equipment_S$ = 4 tons
- The project has no purchased electricity since electricity is generated on-site. $CO_2e\ Purchased_S$ = 0 tons
- CO_2 injected into the storage site is measured such that $CO_2\ Transfer_I$ = 407 tons
- CO_2 that is emitted by equipment located in between the flow meter used to measure injection quantity and the injection well is measured such that $CO_2\ Fugitive_S$ = 1 ton.

$CO_2e\ Emissions_S$ = 408 + 4 + 0 – 407 + 1 = 6 tons

Megawatt-Hours

$Net\ MWh = Net\ MWh_{elec} + Net\ MWh_{Cogen}$

$Net\ MWh_{elec} = MWh\ Generator + MWh\ Auxiliary - MWh\ Consumed$

- 1,000 megawatt-hours are produced by the electric generating unit, so $MWh\ Generator$ = 1,000 MWh
- Electric energy is produced by auxiliary equipment from the storage site's electric generating unit, so $MWh\ Auxiliary$ = 4 MWh
- The electricity consumed by the storage process is measured such that $MWh\ Consumed$ = 4 MWh. (Electricity consumed by the capture and transport processes is treated as indirect emissions and not included in MWh Consumed)
- This is not a cogeneration project, no heat is sold, and $Net\ MWh_{Cogen}$ = 0

$Net\ MWh = Net\ MWh_{elec}$ = 1,000 + 4 – 4 = 1,000 MWh

Emission Rate and EACs Issued

$Emission\ rate = (CO_2e\ Emissions_{G\&C} + CO_2e\ Emissions_T + CO_2e\ Emissions_S)\ /\ Net\ MWh$

- **(45 + 4 + 6) tons / 1,000 MWh = 0.0550 tons/MWh or 121.3 lbs/MWh**
- **1,000 EACs issued**

Illustrative Example #3

This example is similar to Illustrative Example #1, with the following changes:

- The electric generating unit is a cogeneration facility.
- Instead of generating 1,000 MWh of electricity, it generates 975 MWh of electricity, and produces and sells 100 MMBtu of heat. (In Example #1, this heat is captured by a heat recovery steam generator and is used to generate electricity.)

Calculation components that differ from Illustrative Example #1 are underlined.

Generation and Capture Emissions

$CO_2e\ Emissions_{G\&C} = CO_2e\ Generator + CO_2e\ Auxiliary_C + CO_2e\ Purchased_C - CO_2\ Transfer_T$

- Based on fuel input at the electric generating unit, $CO_2e\ Generator$ = 400 tons
- The system requires auxiliary steam to complete the capture process, based on fuel input at the auxiliary boiler, $CO_2e\ Auxiliary_C$ = 30 tons
- There is no purchased energy, as the electricity needed for the capture process is treated as though it is supplied by the generating unit, so $CO_2e\ Purchased_C$ = 0 tons
- The CO_2 transferred to the transport system is measured such that $CO_2\ Transfer_T$ = 410 tons

$CO_2e\ Emissions_{G\&C}$ = 400 + 30 + 0 – 410 = 20 tons

Transport Emissions

$CO_2e\ Emissions_T = CO_2e\ Transfer_T + CO_2e\ Equipment_T + CO_2e\ Purchased_T - CO_2\ Transfer_S$

- Noted before, $CO_2e\ Transfer_T$ = 410 tons
- The project's allocated share of emissions from direct emissions of transport system equipment is $CO_2e\ Equipment_T$ = 2 tons
- The project's allocated share of transport system purchased electricity is 2 megawatt-hours, which are attributed a supplier-specific emission rate of 0.5 tons/MWh. $CO_2e\ Purchased_T$ = 1 ton
- The CO_2 transferred to the storage system is measured such that $CO_2\ Transfer_S$ = 408 tons

$CO_2e\ Emissions_T$ = 410 + 2 + 1 - 408 = 5 tons

Storage Emissions

$CO_2e\ Emissions_S = CO_2e\ Transfer_S + CO_2e\ Equipment_S + CO_2e\ Purchased_S - CO_2\ Transfer_I + CO_2e\ Fugitive_S$

- Noted before, $CO_2e\ Transfer_S$ = 408 tons
- The project's allocated share of emissions from direct emissions of storage system equipment is $CO_2e\ Equipment_S$ = 1 ton
- The project's allocated share of transport system purchased electricity is 4 megawatt-hours, which are attributed a supplier-specific emission rate of 0.5 tons/MWh. $CO_2e\ Purchased_S$ = 2 tons
- CO_2 injected into the storage site is measured such that $CO_2\ Transfer_I$ = 407 tons
- CO_2 that is emitted by equipment located in between the flow meter used to measure injection quantity and the injection well is measured such that $CO_2\ Fugitive_S$ = 1 ton.

$CO_2e\ Emissions_S$ = 408 + 1 + 2 – 407 + 1 = 5 tons

Megawatt-Hours

$Net\ MWh = Net\ MWh_{elec} + Net\ MWh_{Cogen}$

$Net\ MWh_{elec} = MWh\ Generator + MWh\ Auxiliary - MWh\ Consumed$

$Net\ MWh_{Cogen} = Net\ Heat \times (1\ MWh)/(3.412\ MMBtu)$

- 975 megawatt-hours are produced by the electric generating unit, so $MWh\ Generator$ = 975 MWh
- There is no electric energy produced by auxiliary equipment, so $MWh\ Auxiliary$ = 0 MWh
- The electricity consumed by the capture process is measured such that MWh Consumed = 50 MWh. (Electricity consumed by the transport and storage processes is treated as indirect emissions and not included in MWh Consumed)
- **$Net\ MWh_{elec}$ = 975 + 0 – 50 = 925 MWh**
- $Net\ Heat$ = 100 MMBtu
- $Net\ MWh_{Cogen}$ = 100 MMBtu × (1 MWh)/(3.412 MMBtu) = 29.3 MWh

$Net\ MWh = Net\ MWh_{elec} + Net\ MWh_{Cogen}$ = 925.0 + 29.3 = 954.3 MWh

Emission Rate and EACs Issued

$Emission\ rate = (CO_2e\ Emissions_{G\&C} + CO_2e\ Emissions_T + CO_2e\ Emissions_S) / Net\ MWh$

- **(20 + 5 + 5) tons / 954.3 MWh = 0.03144 tons/MWh or 69.3 lbs/MWh**
- **925 EACs issued (based on $Net\ MWh_{elec}$)**

Illustrative Example #4

This example is similar to Illustrative Example #1, with the following changes:

- Electricity provided to the transport and storage segments are considered to be supplied by the primary electric generating unit, as is the electricity provided to the capture process

Calculation components that differ from Illustrative Example #1 are underlined.

Generation and Capture Emissions

$CO_2e\ Emissions_{G\&C} = CO_2e\ Generator + CO_2e\ Auxiliary_C + CO_2e\ Purchased_C - CO_2\ Transfer_T$

- Based on fuel input at the electric generating unit, $CO_2e\ Generator$ = 400 tons
- The system requires auxiliary steam to complete the capture process, based on fuel input at the auxiliary boiler, $CO_2e\ Auxiliary_C$ = 30 tons
- There is no purchased energy, as the electricity needed for the capture process is treated as though it is supplied by the generating unit, so $CO_2e\ Purchased_C$ = 0 tons
- The CO_2 transferred to the transport system is measured such that $CO_2\ Transfer_T$ = 410 tons

$CO_2e\ Emissions_{G\&C}$ = 400 + 30 + 0 – 410 = 20 tons

Transport Emissions

$CO_2e\ Emissions_T = CO_2e\ Transfer_T + CO_2e\ Equipment_T + CO_2e\ Purchased_T - CO_2\ Transfer_S$

- Noted before, $CO_2e\ Transfer_T$ = 410 tons
- The project's allocated share of emissions from direct emissions of transport system equipment is $CO_2e\ Equipment_T$ = 2 tons
- There is no purchased energy, as the electricity needed for the transport segment is treated as though it is supplied by the primary electric generating unit, so $CO_2e\ Purchased_T$ = 0 tons
- The CO_2 transferred to the storage system is measured such that $CO_2\ Transfer_S$ = 408 tons

$CO_2e\ Emissions_T$ = 410 + 2 + 0 - 408 = 4 tons

Storage Emissions

$CO_2e\ Emissions_S = CO_2e\ Transfer_S + CO_2e\ Equipment_S + CO_2e\ Purchased_S - CO_2\ Transfer_I + CO_2e\ Fugitive_S$

- Noted before, $CO_2e\ Transfer_S$ = 408 tons
- The project's allocated share of emissions from direct emissions of storage system equipment is $CO_2e\ Equipment_S$ = 1 ton
- There is no purchased energy, as the electricity needed for the storage segment is treated as though it is supplied by the primary electric generating unit, so $CO_2e\ Purchased_S$ = 0 tons
- CO_2 injected into the storage site is measured such that $CO_2\ Transfer_I$ = 407 tons
- CO_2 that is emitted by equipment located in between the flow meter used to measure injection quantity and the injection well is measured such that $CO_2\ Fugitive_S$ = 1 ton.

$CO_2e\ Emissions_S$ = 408 + 1 + 0 – 407 + 1 = 3 tons

Megawatt-Hours

$Net\ MWh = Net\ MWh_{elec} + Net\ MWh_{Cogen}$

$Net\ MWh_{elec} = MWh\ Generator + MWh\ Auxiliary - MWh\ Consumed$

- 1,000 megawatt-hours are produced by the electric generating unit, so $MWh\ Generator$ = 1,000 MWh
- There is no electric energy produced by auxiliary equipment, so $MWh\ Auxiliary$ = 0 MWh
- The electricity consumed by the capture, transport, and storage processes is measured such that $MWh\ Consumed$ = 50 + 2 + 4 = 56 MWh
- This is not a cogeneration project, no heat is sold, and $Net\ MWh_{Cogen}$ = 0

$Net\ MWh = Net\ MWh_{elec}$ = 1,000 + 0 – 56 = 944 MWh

Emission Rate and EACs Issued

$Emission\ rate = (CO_2e\ Emissions_{G\&C} + CO_2e\ Emissions_T + CO_2e\ Emissions_S)\ /\ Net\ MWh$

- **(20 + 4 + 3) tons / 944 MWh = 0.02860 tons/MWh or 63.1 lbs/MWh**
- **944 EACs issued**

Illustrative Example #5

This example is similar to Illustrative Example #1, with the following changes:

- A system factor is applied to the transport and storage segment emissions to allocate transport and storage emissions from a shared system

This example is designed to produce the same outcome as Illustrative Example #1. Calculation components that differ from Illustrative Example #1 are underlined.

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Generation and Capture Emissions

$CO_2e\ Emissions_{G\&C} = CO_2e\ Generator + CO_2e\ Auxiliary_C + CO_2e\ Purchased_C - CO_2\ Transfer_T$

- Based on fuel input at the electric generating unit, $CO_2e\ Generator$ = 400 tons
- The system requires auxiliary steam to complete the capture process, based on fuel input at the auxiliary boiler, $CO_2e\ Auxiliary_C$ = 30 tons
- There is no purchased energy, as the electricity needed for the capture process is treated as though it is supplied by the generating unit, so $CO_2e\ Purchased_C$ = 0 tons
- The CO_2 transferred to the transport system is measured such that $CO_2\ Transfer_T$ = 410 tons

$CO_2e\ Emissions_{G\&C}$ = 400 + 30 + 0 – 410 = 20 tons

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<u>Transport and Storage Emissions</u>

<u>$CO_2e\ Emissions_T + CO_2e\ Emissions_S = CO_2\ Transfer_T \times System\ Factor$</u>

- Noted before, $CO_2e\ Transfer_T$ = 410 tons
- <u>The system factor provided by the transport and storage system operator is 2.439%. This consistent with the data in Illustrative Example #1: 10 tons of emissions were associated with the transport and storage of 410 tons, and 10 tons / 410 tons = 2.439%</u>

<u>**$CO_2e\ Emissions_T + CO_2e\ Emissions_S$ = 410 tons × 2.439% = 10 tons**</u>

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Megawatt-Hours

$Net\ MWh = Net\ MWh_{elec} + Net\ MWh_{Cogen}$

$Net\ MWh_{elec} = MWh\ Generator + MWh\ Auxiliary - MWh\ Consumed$

- 1,000 megawatt-hours are produced by the electric generating unit, so $MWh\ Generator$ = 1,000 MWh
- There is no electric energy produced by auxiliary equipment, so $MWh\ Auxiliary$ = 0 MWh
- The electricity consumed by the capture process is measured such that MWh Consumed = 50 MWh. (Electricity consumed by the transport and storage processes is treated as indirect emissions and not included in MWh Consumed)
- This is not a cogeneration project, no heat is sold, and $Net\ MWh_{Cogen}$ = 0

$Net\ MWh = Net\ MWh_{elec}$ = 1,000 + 0 – 50 = 950 MWh

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Emission Rate and EACs Issued

$Emission\ rate = (CO_2e\ Emissions_{G\&C} + CO_2e\ Emissions_T + CO_2e\ Emissions_S) / Net\ MWh$

- **<u>(20 + 10) tons</u> / 950 MWh = 0.03158 tons/MWh or 69.6 lbs/MWh**
- **950 EACs issued**

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Illustrative Example #6

This example is similar to Illustrative Example #1, with the following changes:

- A carbon services provider (CSP) elects to pursue separate environmental attributes for emissions reductions from its capture of the emissions from its auxiliary boiler.
- The auxiliary steam required to complete the capture process is treated as indirect emissions. Its indirect emissions are the CO_2e content of the input fuel, treated as if no CO_2 is captured.
- The Registering Entity and CSP agree to allocate Transport and Storage emissions and the megawatt-hours consumed by the capture process based on the ratio of the CO_2 content of their input fuel (400/430=93% to the Registering Entity, 30/430=7% to the CSP).
- The CSP includes its share of capture, transport, and storage emissions in a separate attribute.

Calculation components that differ from Illustrative Example #1 are underlined.

Generation and Capture Emissions

$CO_2e\ Emissions_{G\&C} = CO_2e\ Generator + CO_2e\ Auxiliary_C + CO_2e\ Purchased_C - CO_2\ Transfer_T$

- Based on fuel input at the electric generating unit, $CO_2e\ Generator$ = 400 tons
- The auxiliary steam required to complete the capture process, based on fuel input at the auxiliary boiler, is treated as indirect emissions. 93% of the total steam is required to operate the CCS equipment on behalf of the electric generating unit's capture needs (the other 7% is used to operate the CCS equipment on behalf of the CSP's needs), so $CO_2e\ Auxiliary_C$ = 0 tons and $CO_2e\ Purchased_C$ = 93% × 30 = 27.9 tons
- The CO_2 transferred to the transport system is measured and allocated to the Registering Entity such that $CO_2\ Transfer_T$ = 93% × 410 = 381.4 tons

$CO_2e\ Emissions_{G\&C}$ = 400 +0 +27.9 –381.4 = 46.5 tons

Transport Emissions

$CO_2e\ Emissions_T = CO_2e\ Transfer_T + CO_2e\ Equipment_T + CO_2e\ Purchased_T - CO_2\ Transfer_S$

- Noted before, $CO_2e\ Transfer_T$ = 381.4 tons
- The project's allocated share of emissions from direct emissions of transport system equipment is $CO_2e\ Equipment_T$ = 93% × 2 = 1.9 tons
- The project's allocated share of transport system purchased electricity is 93% × 2 megawatt-hours, which are attributed a supplier-specific emission rate of 0.5 tons/MWh. $CO_2e\ Purchased_T$ = 0.9 ton
- The CO_2 transferred to the storage system is measured such that $CO_2\ Transfer_S$ = 93% × 408 = 379.5 tons

$CO_2e\ Emissions_T$ = 381.4 + 1.9 + 0.9 - 379.5 = 4.7 tons

Storage Emissions

$CO_2e\ Emissions_S = CO_2e\ Transfer_S + CO_2e\ Equipment_S + CO_2e\ Purchased_S - CO_2\ Transfer_I + CO_2e\ Fugitive_S$

- Noted before, $CO_2e\ Transfer_S$ = 379.5 tons
- The project's allocated share of emissions from direct emissions of storage system equipment is $CO_2e\ Equipment_S$ = 93% × 1 = 0.9 ton
- The project's allocated share of transport system purchased electricity is 93% × 4 megawatt-hours, which are attributed a supplier-specific emission rate of 0.5 tons/MWh. $CO_2e\ Purchased_S$ = 1.9 tons
- CO_2 injected into the storage site is measured such that $CO_2\ Transfer_I$ = 93% × 407 =378.6 tons
- CO_2 that is emitted by equipment located in between the flow meter used to measure injection quantity and the injection well is measured such that $CO_2\ Fugitive_S$ = 93% × 1 = 0.9 ton.

$CO_2e\ Emissions_S$ = 379.5 + 0.9 + 1.9 – 378.6 + 0.9 = 4.7 tons

Megawatt-Hours

$Net\ MWh = Net\ MWh_{elec} + Net\ MWh_{Cogen}$

$Net\ MWh_{elec} = MWh\ Generator + MWh\ Auxiliary - MWh\ Consumed$

- 1,000 megawatt-hours are produced by the electric generating unit, so $MWh\ Generator$ = 1,000 MWh
- There is no electric energy produced by auxiliary equipment, so $MWh\ Auxiliary$ = 0 MWh
- The electricity consumed by the capture process is measured such that $MWh\ Consumed$ = 93% × 50 = 46.5 MWh. (Electricity consumed by the transport and storage processes is treated as indirect emissions and not included in $MWh\ Consumed$)
- This is not a cogeneration project, no heat is sold, and $Net\ MWh_{Cogen}$ = 0

$Net\ MWh = Net\ MWh_{elec}$ = 1,000 + 0 – 46.5 = 953.5 MWh

Emission Rate and EACs Issued

$Emission\ rate = (CO_2e\ Emissions_{G\&C} + CO_2e\ Emissions_T + CO_2e\ Emissions_S) / Net\ MWh$

- **(46.5 + 4.7 + 4.7) tons / 953.5 MWh = 0.0585 tons/MWh or 129.0 lbs/MWh**
- **953.5 EACs issued**

Appendix D: System Factor Illustration

	Example Calculations			Emission Rate Inputs with System Factor
EAC Interval	Hour 1	Hour 2	Hour 3	Hour X
Net MWh (MWh)	2	3	2	Net MWh
CO_2e $Emissions_{G\&C}$ (lb)	100	300	200	CO_2e $Emissions_{G\&C}$
CO_2 $Transfer_T$ (lb)	1,500	2,100	1,400	CO_2 $Transfer_T$
System Factor	$\frac{500}{1{,}500 + 2{,}100 + 1{,}400} = 0.1$			$\frac{CO_2e\ Emissions_T + CO_2e\ Emissions_S}{\sum_{hours} CO_2\ Transfer_T}$
Emission Rate (lbs/MWh)	$\frac{100 + 150}{2} = 125$	$\frac{300 + 210}{3} = 170$	$\frac{200 + 140}{2} = 170$	$\frac{CO_2e\ Emissions_{G\&C} + System\ Factor * CO_2\ Transfer_T}{Net\ MWh}$

To issue an hourly EAC, the Registering Entity submits verified power generation data; verified generation and capture CO_2e emissions data for each hour (100, 300, and 200 lbs); and verified transport and storage emissions data for the whole period (500 lbs). It allocates the transport and storage emissions to the EACs issued in each hour according to the mass of CO_2 transferred to the transport segment in that hour. In this example, the attribute holder claims 7 MWhs of CCS EACs and reports 1,100 emissions in their Scope 2 inventory.

Appendix E: Well Control and Integrity Management Training

To ensure the long-term containment of injected CO_2 and to mitigate potential leakage pathways, the Registry may require or recommend that all personnel involved in the design, operation, and monitoring of CO_2 injection and storage wells undergo specialized Well Control and Integrity Management training.

The training program is recommended to encompass the following:

- **CCS Training**: This encompasses specialized training programs designed for personnel involved in Carbon Capture and Storage projects. Such training addresses the unique operational and safety aspects of CO_2 capture, transport, and geological sequestration. It complements well control and integrity management by providing a broader understanding of the CCS project lifecycle and associated risks, particularly concerning the long-term containment of injected CO_2.
- **Advanced Well Control**: This instruction will cover theoretical and practical aspects of pressure control in CO_2 injection wells, including kick detection, well shut-in procedures, wellbore stability considerations, and subsurface fluid dynamics specific to CO_2 storage operations. This includes training equivalent to that provided for Workover and Well Intervention for Well Site Managers, Consultants, and Engineers.
- **Well Integrity Management**: This module will address the comprehensive management of wellbore integrity throughout the lifecycle of CO_2 injection and storage wells. Key topics include casing and cementing design, corrosion prevention and monitoring, wellhead maintenance, identification and remediation of potential leakage pathways (e.g., through legacy wells or compromised seals), and long-term well abandonment procedures.
- **Emergency Response Protocols**: All training must include detailed emergency response planning for well control events, well integrity breaches, or potential CO_2 leakage scenarios. This includes simulated exercises for rapid response, containment strategies, and coordination with relevant regulatory bodies.

Personnel receiving this training may include, but not be limited to, Well Site Managers, Drilling Engineers, Completion Engineers, Reservoir Engineers involved in CO_2 injection operations, and any other technical personnel responsible for well operations or integrity monitoring. Verification of competency through an accredited certification program, along with requirements for periodic refreshers and recertification, may be required to ensure ongoing proficiency with evolving technologies and regulatory standards.